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March 18, 2026

Public Utility Commission
Attn: Filing Center
P.O. Box 1088
Salem, OR 97308-1088

Re: UG 527 – CUB Opening Testimony and Workpapers

Dear Filing Center:

The Oregon Citizens' Utility Board ("CUB") hereby submits CUB's Opening Testimony in the aforementioned docket. CUB has submitted its related workpapers and Excel exhibits in their native format via Huddle.

Please let me know if you have any questions or concerns.

Respectfully submitted,

/s/Lizzie Lesch-Abhaya

Lizzie Lesch-Abhaya
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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UG 527

In the Matter of	)
	)
NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL,	)
	)
Application for an Alternative Rate Mechanism, New Schedule 123.	)
	)

OPENING TESTIMONY

OF THE

OREGON CITIZENS' UTILITY BOARD

March 18, 2026

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UG 527

OPENING TESTIMONY OF SARAH WOCHELE AND BOB JENKS
ON BEHALF OF THE OREGON CITIZENS' UTILITY BOARD

CUB 100

March 18, 2026

Residential Customer Impact of Rate Increase
Wrongful Disconnections during Winter Moratorium
Alternative Rate Mechanism

Q. Please state your name, occupation, and business address

A. My name is Sarah Wochele. I am an Equity Analyst & Advocate employed by Oregon Citizens' Utility Board (CUB). My business address is 610 SW Broadway, Ste. 400 Portland, Oregon 97205.

A. My name is Bob Jenks. I am the Executive Director of the Oregon Citizens' Utility Board (CUB). My business address is 610 SW Broadway, Ste. 400 Portland, Oregon 97205.

Q. Please describe your qualifications.

A. Sarah Wochele's witness statement is provided in Exhibit CUB/101. Bob Jenks' witness statement is provided in Exhibit CUB/102.

Q. What is the purpose of this Joint Testimony?

A. The purpose of this testimony is to center the residential customer in this proceeding. This includes discussion of customer impacts stemming from unaffordability of NW Natural ("NWN" or "the Company") monthly bills in the face of back-to-back-to-back rate increases from the Company since 2023. We have been in a major rate proceeding (General Rate Case or multi-issue Alternative Rate Mechanism) with NWN every month except two months since December, 2023. We highlight our concerns about certain vulnerable customers in NWN's territory. Not all of these vulnerable customers are accounted for in the Company's analysis of how this rate increase will impact energy burden for known low-income customers.

Related to this, we raise high-level concerns about not getting to some root cause issues of unaffordability related to energy inefficiency and low-income customers with high gas usage. We raise concerns about the Company's error regarding the disconnection of its known vulnerable customers in the second half of November and all of December

2025, when those customers were supposed to be receiving protection. Lastly, we also discuss our concerns with the Company's use of an Alternate Rate Mechanism (ARM), which includes a discussion on how utility reliance on even more, unchecked multi-issue ARMs is out of alignment with the 2025 FAIR Energy Act (HB 3179) and requires Commission action.

Q. Are you sponsoring any exhibits?

A. Yes. Exhibits 101-132.

Exhibit 101	Wochele Witness statement
Exhibit 102	Jenks' Witness statement
Exhibit 103	AR 677 Rulemaking General Rate Revisions HB 3179 – Staff Transition Period Concept
Exhibit 104	Residential Customers Rates Increasing
Exhibit 105	UE 459 Opening Testimony of the Oregon Citizens' Utility Board
Exhibit 106	HB 2475 (2021) The Energy Affordability Act Bill Text
Exhibit 107	UE 459 Memorandum of Understanding (MOU)
Exhibit 108	RO 16 NW Natural 2025 Q4 Energy Burden Metric Data Report
Exhibit 109	RO 16 NW Natural 2025 Supplement High Usage Report
Exhibit 110	2024 NW Natural Energy Burden Assessment (EBA)

Exhibit 111	UM 2211: Energy Justice Advocates and Community Based Organizations' request for a process to explore protections for immigrants and refugees' customer data and energy security (February 2026)
Exhibit 112	American Immigration Council: The Chilling Effect of Trump's Indiscriminate Immigration Arrests & Propaganda (February 2025)
Exhibit 113	Pacific Northwest National Laboratory: Oregon's Existing Utility Rates and Related Mechanisms
Exhibit 114	CUB DR 11 Attachment
Exhibit 115	RO 16 NW Natural 2025 Energy Burden Metric Reports
Exhibit 116	RO 16 NW Natural 2026 Q1 Energy Burden Metric Report
Exhibit 117	CUB DR 7
Exhibit 118	UG 490 Staff's Opening Testimony
Exhibit 119	Gas Stove Pollutants: Consequences on Indoor Air Quality and Health (2025)
Exhibit 120	Association between income, employment status, and asthma outcomes: a systematic review and meta-analysis (2025)
Exhibit 121	HB 3179 (2025) The FAIR Energy Act Bill Text
Exhibit 122	Letter from Senators Deb Petterson et al. regarding Utility Shutoffs Amid the Federal Government Shutdown (November 2025)
Exhibit 123	CUB DR 34
Exhibit 124	PRESS RELEASE: Oregon Senator Deb Patterson and Colleagues Secure Commitments to Keep Service Connected for Struggling Families (November 2025)

Exhibit 125	KOIN: PNW utility companies agree to help customers impacted by government shutdown (November 2025) available at https://www.koin.com/news/oregon/pnw-utility-companies-help-customers-impacted-government-shutdown/
Exhibit 126	UTC Docket UG-250610 Response Testimony of Shaylee N. Stokes, Director of the Energy Project
Exhibit 127	AR 671/UM 2211 - Energy Justice Advocate Comments for additional metrics and reporting associated with evaluating Division 21 protections (February 2026)
Exhibit 128	NWN response to CUB DR 31 Supplement
Exhibit 129	NWN response to CUB DR 33 Attachment
Exhibit 130	The Future of Heat Initiative (FOHI) (March 2026)
Exhibit 131	UG 490 NW Natural Reply Testimony (June 2024)
Exhibit 132	NWN response to CUB DR 35

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I. CUSTOMER IMPACTS: "DEATH BY A THOUSAND CUTS"

Rates are Increasing for Residential Customers

Q. How much is NW Natural proposing to change residential customer rates in this Alternative Rate Mechanism (ARM) filing?

A. NW Natural is requesting a 1.4% rate increase for its residential customers. This would add about $1.40/month to the average household's monthly bill. In December, this increase would be about $2.80/month more for the average household.[1] For the average customer receiving 15% off their monthly bill via the Company's Bill Discount Program (BDP), the annual average increase is $1.18/month and $2.38 in the month of December.[2]

Q. How have NW Natural's residential customer rates changed over time?

A. NWN has had major rate proceedings (GRCs or ARM) in four out of the last five years. See CUB Figure 1.

Figure 1: NW Natural GRCs and ARMs

Docket	*Rate Effective Date*
UG 435	11/1/2022
UG 490	11/1/2024
UG 520	10/31/2025
UG 527	10/31/2026

It is important to recognize that NWN allocates the bulk of the Company's costs to Oregon households. CUB Figure 2 looks at NWN margin rates. This represents the cost

[1] CUB/114 Wochele-Jenks/1.
[2] *Id.*

to customers, not including the gas commodity. This shows the costs that are largely under NWN's control and creates a better comparison with transport customers because they do not purchase the gas commodity from NWN but use NWN's system to deliver third-party gas. It is important to look not just at the increase in rates as a percentage, but the overall level of increase on a cents/therm basis. Because residential rates are substantially higher than other customer classes, a 10% increase in residential rates is a much higher overall increase in cents/therm, than a 10% increase to other customer classes.

Figure 2: Residential Customers Bear the Brunt of Rate Increases[3]

Rate Class	Margin Increase since 10/2022 including UG 427 (cents/therm)	Margin Increase since 10/2022 including UG 427 (% increase)	percent of margin allocated to class
Residential	***31.96***	***43%***	***66.75%***
3C	27.60	50%	24.32%
3I	11.00	26%	0.42%
31CSF	8.90	23%	1.68%
31CTF	9.57	25%	0.18%
31ISF	7.06	27%	0.54%
32CSF	5.60	21%	2.37%
32ISF	1.41	8%	0.65%
32CTF	2.97	19%	0.17%
32ITF	0.28	3%	1.12%
32CSI	3.04	34%	0.42%
32ISI	1.00	11%	0.44%
32CTI	0.43	6%	0.09%
33ITI	0.28	9%	0.86%

CUB Figure 2 shows that since October 2022, residential rates have increased by approximately 32 cents/therm, while some classes of customers have seen an increase of less than 1 cent/therm. In addition, more than two-thirds of the costs of NWN's non-gas

[3] CUB/104 Wochele-Jenks/1.

costs are assigned to residential customers and more than 90% of the costs are assigned to residential and small commercial customers.

What's more, a study by the Freedom of Heat Initiative (FOHI), found that on average "about two-thirds of a typical gas bill goes to delivery charges, not the gas itself."[4] The delivery charges are the same as the margin charges in the chart above. The study was authored by Jamie Van Nostrand, the Policy Director at FOHI. Mr. Van Nostrand is the former Chair of the Massachusetts Department of Public Utilities and previously practiced law in the Pacific Northwest. In the study, Mr. Van Nostrand explains that costs for delivering gas to customers has almost doubled in the past 14 years due to the strong incentive by gas companies to spend more money on infrastructure that they can then charge customers for.[5]

Households in NWN territory are experiencing year-over-year increases from the Company since 2022. With the current ARM, NWN's residential rates excluding gas costs will have gone up by 43% since October 2022.[6] For an individual residential customer using 650 therms per year this is an increase of $207/year – the bulk of which will come from winter bills. As purchased gas prices increase due to CPP compliance costs and market disruptions, these rate increases will strain the ability of residential customers to afford NWN's service. As a result, this will increase the risk posed by stranded assets as customers leave to avoid the high costs and are no longer available to pay off the marginal cost additions. In consequence, there is a risk that these stranded asset costs will then be placed on those without the ability to pay and thereby increasing disconnections.[7]

[4] CUB/130 Wochele-Jenks/1. *See also* CUB/113 Wochele-Jenks/40-41.
[5] *See id.* at 1-2.
[6] CUB/104 Wochele-Jenks/1.
[7] *See* CUB/316 Jenks-Dougan/24-25, 30, 33-34.

Q. Does CUB agree with NWN's claim that this filing, as well as this type of filing, is necessary for customers to "smooth rates" as an interim measure during Oregon's transition to multi-year plans?

A. No. CUB is skeptical that that is the purpose. CUB believes that the purpose of the ARM is to get cost recovery and avoid regulatory lag. Because regulatory lag is one of the few incentives that exist to control costs and reduce new investment, CUB is concerned that in the long run, ARMs will lead to higher rates.

NWN states it filed this ARM "to recover the costs of a limited subset of capital additions through a new base rate tariff, Schedule 123."[8] But NWN controls the timing of its rate cases. To put this in perspective, the Commission can look at the outcome of UE 435. There PGE could have filed its rate case so that the rate effective date coincided with Seaside's rate effective date. Instead PGE requested two rate effective dates, one on January 1st and the other later in the year to recover the tracked Seaside costs.[9] Likewise, NWN could have filed UG 520, its 2025 general rate case, to coincide with the rate effective date for the "limited subset of capital additions" or it could wait until its next rate case for this recovery. Either way would entail some regulatory lag. Thus, the Company is avoiding regulatory lag by using these back-to-back proceedings.

The Harm from Rate Hikes Affects Some Customers More Than Others

Q. What is the difference between energy burden and energy insecurity?

[8] NWN Initial Filing, *UG 527; NWN OPUC Advice No. 25-25,* at 1 (Nov. 25, 2025).
[9] *See* Order No. 24-454 3-4, 43-45.

A. Energy insecurity is understood as an inability to adequately meet household energy needs, and this can be acute or chronic.[10] A lack of energy security leads to energy poverty. An example of energy poverty is a household never starting gas service with a utility in the first place and opting to cook with propane instead.[11] There are at least three core dimensions to energy insecurity:

1. Economic: the disproportionate share of household income allocated to utility expenses (i.e. energy burden)
2. Physical: deficient and inefficient housing structures impacting comfort and costs, this includes infrastructure deficits (e.g. no air conditioning and an old, unweatherized house)
3. Coping: energy related behavioral and adaptive strategies to manage physical and economic hardship (for example, energy limiting behaviors such as not turning the heat up in the winter and wearing jackets indoors)

Energy burden in this context is generally understood as the percentage of a household's gross income that is spent on its energy bills—meaning it is a dimension of energy insecurity. To date, conversations about energy insecurity in the regulated energy space have been dominated by energy burden. Where this becomes especially limiting is considerations around energy limiting behaviors and infrastructure deficits due to affordability. For example, in the summer a family's energy burden may calculate to being

[10] Dr. Diana Hernandez from Columbia University has defined and operationalized the concept of energy insecurity. *See* more here: www.publichealth.columbia.edu/research/programs/energy-equity-housing-health/what-energy-insecurity.

[11] CUB has heard from community partners that this is a reality at least in NWN territory, as some people were limited in establishing service due to the Company's prior requirements to start an account. There were primarily concerns around requests for social security numbers.

low or moderate, but it is because they do not have air conditioning as they cannot afford to buy one and run it.

Q. Are there residential customer types who CUB thinks may be particularly vulnerable to back-to-back rate increases?

A. Yes. The energy security of the following residential customers is increasingly precarious in the face of back-to-back rate increases. Generally, CUB is currently concerned about impacts on the following customer groups:

- **Customers living on low fixed incomes**.
- **Customers with low incomes experiencing various symptoms of energy insecurity** who are not yet benefiting from the Bill Discount Program (BDP).
- **Immigrant and refugee households whose energy insecurity is worsening** due to ongoing threats by federal immigration action, especially those who are forced to navigate the chilling effect[12] and those whose households have faced deportations.[13]
- **Households who have incomes at 61-100% State Median Income (SMI)—the "energy assistance gap" or the "energy assistance hole"** where there are little to no possibilities for receiving energy assistance despite households with this income experiencing high energy burden. For example, the experience of those who are Asset Limited, Income Constrained, and Employed. Per the 2024 Energy Burden Assessment (EBA) 13% of NWN households fall into this category.[14]

[12] *See* CUB/112 Wochele-Jenks/3 (The "chilling effect" is where the threat itself of aggressive immigration enforcement imposes fear on immigrant and minority communities. They become scared to leave the house, go to work, or attend school as these everyday activities could end in detention and deportation of themselves or their loved ones).
[13] CUB/111 Wochele-Jenks/4.
[14] CUB/110 Wochele-Jenks/68-70.

- **Households with low-incomes *and* high gas usage.**

Q. How have these recent rate increases impacted customers' energy security generally?

A. Households living with certain vulnerabilities are experiencing more impacts to their energy security from unaffordable bills. This shows up in chronic arrears, cycles of disconnection for non-payment, chronic high usage, high energy burden, and the energy limiting behaviors and difficult choices families are forced into that we cannot also measure quantitatively. Disconnections and chronic arrears (90+ day arrears), however, are two reliable metrics for measuring energy insecurity. In October 2022, NWN started its Bill Discount Program (BDP) in response to HB 2475 (2021). In 2025, the Company disconnected 12,363 households for non-payment.[15] Of these households who were disconnected in 2025, just over one third of them were enrolled in the BDP at the time of being disconnected by the Company.[16] In January 2026, three months after a 5.5% rate increase as well as the middle of winter, one third of NWN's customers with arrears over 90 days old, were known low-income customers, those enrolled in the BDP.[17]

Looking at the number of customers in Time Payment Arrangements (TPAs) also tells us how many customers are struggling to afford their bill payments in full. TPAs are payment plans that break down a customer's past due bills equally across twelve months or twenty-four. As of January 2026, there were 5,485 households enrolled in a TPA—though these enrollment numbers do not tell us if these households were able to "successfully" complete

[15] *See* CUB/115 Wochele-Jenks/at 20, 24, 30, 39 (The reports are made quarterly and each covers three months. CUB determined NWN disconnected 12,363 households for non-payment by the sum of each set of three months).
[16] *Id.*
[17] CUB/116 Wochele-Jenks/8.

their TPA on top of their existing monthly bills before entering the disconnection cue.[18] Instead, these data just highlight customers making attempts to manage their unaffordable bills and help avoid or delay disconnection.

Q. As energy burden is one economic metric of energy insecurity, did NW Natural conduct an analysis of how its customers' energy burden would be impacted by its proposal to raise rates?

A. Yes. We appreciate that NWN took the initiative to provide an energy burden analysis for its known low-income customers—those enrolled in its Bill Discount Program (BDP). The Company is not required to do a full Cumulative Economic Impact Analysis for the residential customer class with this ARM filing as ROE is not under consideration. See CUB Figure 3 for the Company's analysis from its initial filing.

[18] *Id.* at 3.

Figure 3: NW Natural's Energy Burden Analysis in UG 527[19]

Table 5 - NW Natural Bill Discount Effectiveness Targeting 2 Percent Energy Burden

Assuming family of 4	Tier 3 Example	Tier 2 Example	Tier 1 Example	Tier 0 Example
NW Natural bill discount tier	15%	30%	50%	85%
average annual usage	651	651	651	651
annual bill	$1,038.88	$1,038.88	$1,038.88	$1,038.88
Mid point of income for the tier	$64,590	$46,135	$27,681	$9,227
Existing				
NW Natural bill discount	$155.83	$311.66	$519.44	$883.04
annual bill after bill discount	$883.04	$727.21	$519.44	$155.83
Annual Bill as a % of income before discount	1.6%	2.3%	3.8%	11.3%
Annual Bill as a % of income after discount	**1.4%**	**1.6%**	**1.9%**	**1.7%**
ARM increase - illustrative	1.6%			
annual bill	$1,055.50	$1,055.50	$1,055.50	$1,055.50
NW Natural bill discount	$158.32	$316.65	$527.75	$897.17
annual bill after bill discount	$897.17	$738.85	$527.75	$158.32
Annual Bill as a % of income before discount	1.6%	2.3%	3.8%	11.4%
Annual Bill as a % of income after discount	**1.4%**	**1.6%**	**1.9%**	**1.7%**

Q. How does the Company analyze the way its proposed rate increase will impact energy burden for its known low-income customers?

A. As shown above, the Company's analysis looks at each of its Bill Discount Program (BDP) tiers, the corresponding discounts, the midpoint of income based on the income guidelines for each tier based on a household size of four, and average annual residential usage as well as the annual bill resulting from that usage. The Company uses this information to also calculate annual energy burden for enrolled customers, with the annual bill as a percentage of income after the discount is applied. Additionally, it illustrates what a BDP customer's

[19] NWN/100 Kravitz-Walker/20.

annual bill looks like currently, both before and after the discount, as well as what the annual bill for each tier looks like with the proposed ARM increase. The Company uses a 2% annual energy burden threshold to consider what high energy burden is based on the outcomes of its 2024 Energy Burden Assessment (EBA), which specifically addresses 2% as the "high-burden threshold" for NWN's territory.[20]

Q. What does NW Natural's energy burden analysis find?

A. On the whole, NWN concluded that the "overall 1.4% revenue requirement increase associated with the ARM is reasonable and would not compromise energy equity and affordability."[21] From the Company's energy burden analysis for enrolled BDP customers specifically, it found that the BDP is "bringing energy burden rates to an affordable level for eligible customers."[22] Though it is important to clarify that "eligible" is not the same as being enrolled in and benefitting from the program. There are many eligible customers whose energy burdens are still high because they have not yet learned about and enrolled in the BDP. Overall, NWN's energy burden analysis shows that after the proposed ARM increase, when considering the midpoint of income for each tier, and customers with average energy use, these accounted-for-customers' energy burdens (and those with incomes above the midpoint) would stay the same as they currently are without the ARM increase.[23]

Q. What are the limitations of the Company's analysis?

There are at least four limitations:

[20] CUB/110 Wochele-Jenks/20.
[21] NWN/100 Kravitz-Walker/19.
[22] *Id.* at 20.
[23] *Id.*

1. The Company relies on energy burden calculations for a limited group of its customers, along with the mere existence of its Oregon Low-Income Gas Assistance (OLGA) and Arrearage Management Program (AMP) programs, as evidence of customer affordability and energy equity considerations.[24]
2. The Company relies on the midpoint of each income tier to assess the energy burden for customers across the entire income range in each tier.[25]
3. The Company uses the average residential customer usage despite being required to track average usage at the tier level in RO 16 Energy Burden Metric Reporting (EBMR).[26]
4. Customer bills will increase, not by 1.4%, but by this amount plus the changes in the gas commodity and the various single issue rate mechanisms that go into effect with the Purchased Gas Adjustment (PGA). A 1.4% increase, when combined with increases in those costs, will only increase energy burden.

Q. Please describe the limitations of relying solely on an energy burden analysis of known low-income customers to understand the status of energy equity and affordability for residential customers.

A. Generally, while the energy burden metric is useful, it is a limited metric, and it is especially limited when used in isolation to assess the state of energy equity and energy affordability—which is essentially what the Company did. Again, over one third of customers in chronic arrears as of January 2026 were known low-income customers (aka those enrolled in the BDP), so we know that at least these 4,972 families cannot afford

[24] NWN/100 Kravitz-Walker/ 19-21.
[25] *Id.* at 20.
[26] CUB/117 Wochele-Jenks/1.

NWN's proposed increase.[27] And the chronic arrears of the other 9,608 families suggest these families also cannot afford this increase.[28] Further, high energy burden thresholds of 2% for gas utilities, and 6% for electric utilities, result in the assumption that it is equitable for low-income families to have higher energy burdens than higher income households do—as these higher income households are often spending much less of their income on their energy bills.

Q. Please describe the limitations of the Company using the midpoint of income for each tier in its energy burden analysis.

A. The Company's rationale for using the midpoint of each tier's income range was that it was consistent with the most recent design of the BDP and that this "provides better coverage of reduced energy burden throughout each tier."[29]

Q. What do you mean by "consistent with the most recent design of the BDP" and that this "provides better coverage"?

A. The Company most recently altered the discounts in its BDP through its 2024 General Rate Case, UG 490.[30] In that case, the Company utilized this methodology to make its initial proposal for altering the BDP. However, the final outcome for the updated BDP resulted in discounts that were deeper than those the Company proposed in its initial proposal.

In UG 490 the Company explains that in the BDP's original design, the maximum income of a tier was used to estimate energy burden.[31] It stated that using the midpoint instead was an "improvement upon the original design of the bill discount program by providing

[27] CUB/116 Wochele-Jenks/8.
[28] *Id.* at 3.
[29] CUB/117 Wochele-Jenks/1.
[30] Order 24-359 at 60.
[31] CUB/131 Wochele-Jenks/126.

additional coverage for the members of the tier than the prior bill discount program." Thus, it appears the Company is comparing the idea of "better coverage" to support the rationale for its analysis in UG 527 to the methodology which previously provided less coverage (the maximum income of a tier), but not to a third option—for example, the low-point of income in a tier. In UG 490 the Company believed that using the midpoint ensured that discounts were "calibrated to the needs of the 'average' household rather than the highest or lowest incomes, which aligns with our shared goals of delivering resources where they are needed most."[32]

Q. Does CUB agree with NWN's methodology and rationale?

A. No, CUB disagrees with this methodology and rationale. As discussed further below, Staff also disagreed with this methodology when the Company relied on it in UG 490 finding the methodology was unsupported by the evidence.[33]

Relying on the midpoint of an income range rather than the low point to illustrate customer energy burden impacts leaves the realities of customers with the lowest incomes of each tier unaccounted for. In other words, this methodology ignores the lowest income customers and does not paint a full picture of energy burden impacts for each tier. Yet households with the lowest incomes in each tier are arguably more vulnerable based at least on the premise of having less available income to apply to energy bills. Additionally, using the midpoint assumes a normal income distribution in each tier, when it could be the case that each income's distribution skews lower or higher, rendering the analysis not representative. Consequently, the rate increase is most pronounced for the highest burdened

[32] CUB/131 Wochele-Jenks/126-127.
[33] CUB/118 Wochele-Jenks/196-199.

and lowest income households but this segment is overlooked under NWN's mid-point methodology.

Q. Can you provide an example of what this looks like with NWN's BDP tiers?

A. Yes. For example, NWN's Tier 1 analysis, for those four person households with incomes at 16-30% SMI, shows that customers with incomes at the midpoint of this range ($27,681 as identified by NWN, CUB is assuming ~22-23% SMI) have a 1.9% energy burden—just under the high burden threshold of 2%. From this, NWN determines that energy burdens are being kept below 2% for all customers in this tier, both currently and with the ARM increase. But if we look at the lowest income in Tier 1's range, 16% of SMI for a household size of four ($19,684.32),[34] everything else the same, energy burden for these customers is actually 2.6% currently, and would be 2.7% with the ARM. See CUB Figure 4. Its worth nothing in Figure 4 that the current rates in place from UG 520 that went into effect last fall, customers in the lower even of Tiers 1 and 0 are above the 2% energy burden mark.

Figure 4: NW Natural Bill Discount Effectiveness Targeting 2% Energy Burden Using Each Tier's Lowest Income

Assuming Family of 4	Tier 3 (46-60% SMI)	Tier 2 (31-45% SMI)	Tier 1 (16-30% SMI)	Tier 0 (0-15% SMI)
NW Natural BDP Discount	15%	30%	50%	85%
Avg Annual Usage	651	651	651	651
Annual Bill	$1038.88	$1038.88	$1038.88	$1038.88
Low Point of Income for Tier	**$56,592.42 (46% SMI)**	**$38,138.37 (31% SMI)**	**$19,684.32 (16% SMI)**	**$1,230.27 (1% SMI)**
EXISTING				
Bill Discount	$155.83	$311.66	$519.44	$883.04
Annual Bill After Discount	$883.04	$727.21	$519.44	$155.83
Annual Bill as a % of Income Before Discount	1.8%	2.72%	5.28%	84.4%
Annual Bill as a % of Income After Discount	**1.6%**	**1.9%**	**2.6%**	**12.7%**

[34] Calculated using Oregon's 2026 State Median Income, adjusted for a household size of 4: $123,027.

PROPOSED ARM INCREASE	1.6%			
Annual Bill	$1055.50	$1055.50	$1055.50	$1055.50
Bill Discount	$158.32	$316.65	$527.75	$897.17
Annual Bill After Discount	$897.17	$738.85	$527.75	$158.32
Annual Bill as a % of Income Before Discount	1.9%	2.8%	5.4%	86%
Annual Bill as a % of Income After Discount	**1.6%**	**1.9%**	**2.7%**	**12.9%**

Q. How does CUB's analysis in CUB Figure 4 dispute what the Company found in its own energy burden analysis?

A. Accounting for the lowest income in each tier points out that current NWN customer bills for those on the lower end of income in each tier, for three out of four tiers, are already experiencing energy burdens greater than 2% with current NWN rates. The ARM would slightly worsen that energy burden. See CUB Figure 4. As we do not know the income distribution for each tier currently, another option to paint a fuller picture of energy burden impacts for customers enrolled into the BDP is to use the lowest income in each tier as well as the highest income of each tier. This allows us to craft a range of energy burdens to better understand impacts for BDP enrolled customers in each tier. Calculating at the lowest incomes helps illustrate the oversight in the Company's analysis.

The Company's analysis also shows that those BDP customers in the two lowest income tiers (Tier 0 and Tier 1), who are at the midpoint in each income range, currently have the highest energy burdens of all the Company's BDP tiers, teetering closest to the 2% threshold (1.7% and 1.9% respectively). In CUB's analysis provided in Figure 4 this remained true, but energy burdens were worse than in the Company's analysis. This

highlights the limitations of the BDP's design (and analysis for that matter) targeting the midpoint, as the lower someone's income is in each tier, the worse off they are as compared to those with higher incomes in each tier. Under the Company's own analysis, which has customers in Tier 1 with incomes at 16-30% SMI holding at 1.9% energy burden, what will the Company do when it seeks to raise rates again and its own analysis shows energy burdens are greater than 2%?

Q. What were Staff's critiques of the Company's energy burden analysis methodology in UG 490?

A. Staff raised concerns that the Company's methodology, which NWN was using at the time to determine changes to its BDP, did not adequately consider income distributions and levels of energy burden among participants.[35] Staff describe it as overlooking critical areas of need for households at the lower end of income ranges, particularly those with the lowest incomes and highest burdens.[36] As is illustrated in CUB's Figure 4, Staff point out that this particular design has "rapidly declining benefits for those deeper in need."[37] Thus, the design, and the analysis itself do not prioritize the lowest incomes with the highest burden, as was what Staff recommended at the outset of UM 2211 when interim bill discount programs were created in response to HB 2475 (2021).[38] Staff also highlight concerns related to how this methodology does not account for customers who are on the higher end of usage patterns.[39] When CUB asked the Company about its approach in this regard, especially given we know the Company has more representative usage data for each BDP

[35] CUB/118 Wochele-Jenks/196.
[36] *Id.* at 197.
[37] *Id.* at 198.
[38] *Id.* at 199.
[39] *Id.* at 197.

tier, NWN responded that it used, "a methodology previously used in illustrating bill discount program impacts and was used here for consistency and comparability."

Q. Given what CUB has presented here, and the deficiencies Staff also identified in UG 490, why is NWN still using this methodology to determine energy burden for its Bill Discount Program customers, and thus assess whether the rate increase is affordable?

A. NW Natural appears to generally find that consistency and comparability with its previous analysis matters more than updating its analysis in order to be in alignment with Staff's previous critiques to ensure a more accurate assessment.

Q. Can CUB explain its concerns regarding the Company's low-income, high usage customers?

A. In November 2025, the Company identified 8,627 Bill Discount Program (BDP) households who qualified as a "high-usage customer."[40] This is roughly 18% of NWN's bill discount program customers—nearly 1 in 5 known low-income households. [41] A "high-usage customer" is defined as "a residential customer participating in a utility-administered bill discount program whose energy consumption places them in the 90th percentile or above of all other bill discount program participants within the utility's service area."[42] The average usage amongst these high-usage customers was 73 therms/month, while the average overall residential usage that month was 47.2 therms/month.[43] These customers' average bill in November 2025 was $109.87,[44] this is *after* their monthly bill discount, while the overall average residential customer bill was $77.04.[45] In other words, even

[40] CUB/109 Wochele-Jenks/3.
[41] According to NWN's RO 16 2025 Q4 Energy Burden Metric Report, there were 48,027 households who received a BDP discount in November 2025. *See* CUB/108 Wochele-Jenks/6.
[42] OAR 860-021-0408(m).
[43] CUB/108 Wochele-Jenks/5.
[44] CUB/109 Wochele-Jenks/3.
[45] CUB/108 Wochele-Jenks/5.

though these customers were enrolled in the BDP, their average bill was still 43% higher than the average residential customer.

Of these high-usage customers in November (the month which tracked the largest number of high usage customers in 2025) ~19% of them were in chronic arrears, which means nearly 1 in 5 had arrears that were 90 days and older.[46]

Q. What is the Company's proposal to address chronic arrears for love-income high-usage customers?

A. The Company relies on energy efficiency to address this issue, that is replacing the customers' existing gas appliances with more efficient gas appliances. The Company's 2024 Energy Burden Assessment (EBA) noted that while energy efficiency "potential" was concentrated in a small segment of low-income households, this still amounted to 12,000 households who would potentially be good candidates for energy efficiency measures. Yet the problem remains that these energy efficiency programs serve relatively few households.[47]

Q. Does CUB have concerns with this strategy?

A. Yes. In 2026, continuing to lock low-income families into unhealthy fossil fuel appliances is a poor energy efficiency strategy in the face of worsening climate change. It also directly contradicts Oregon's ongoing imperative to work towards a just energy transition and our understanding of environmental justice.[48]

Q. How does NWN's strategy implicate environmental justice?

[46] CUB/109 Wochele-Jenks/3.
[47] CUB/110 Wochele-Jenks/66.
[48] A "just transition" refers to addressing climate change in a fair, just and inclusive manner. This includes taking an inclusive approach to managing challenges associated with the low-carbon transition.

A. Low-income energy efficiency programs, such as NWN's Oregon Low-Income Energy Efficiency (OLIEE) program, which install new fossil fuel appliances, arguably cause long-term harm to low-income households by keeping them chained to the gas system for even longer. For example, a new high efficiency gas furnace typically has a useful life of 15-20 years. This pushes low-income households 15-20 years out from electrification of the heating in their homes. While a gas furnace may have a low operating cost today, as Renewable Natural Gas (RNG), hydrogen, and other alternative fuels get added to NWN's system, the price to run that furnace will increase significantly over the next 20-25 years.

Relatedly, new gas stoves have useful lives of 13-15 years. Meanwhile, a growing body of research shows that there are serious negative health implications stemming from fossil fuel appliances in one's home, especially around gas stoves and air quality.[49] Gas stoves emit nitrogen dioxide, carbon monoxide, and particulate matter, pollutants many studies show are linked to asthma, respiratory issues, and other long term health problems.[50] Low-income families are already more likely to be living in areas with poor outdoor air quality and have an increased likelihood of having asthma.[51] This is especially true for children in low-income families.[52] Setting low-income families up for this is not environmental justice.

The lack of a fuel switching policy for Oregon Investor-Owned Utilities is misaligned with both Oregon's Climate Protection Program (CPP) and Oregon's Energy Affordability Act. For example, HB 2475 (2021), the Energy Affordability Act, defines Environmental Justice

[49] CUB/119 Wochele-Jenks/1-5.
[50] *Id.*
[51] CUB/120 Wochele-Jenks/14.
[52] *Id.* at 15.

in part as "equal protection from environmental and health hazards."[53] And defines Environmental Justice Communities as those that:

> includes communities of color, **communities experiencing lower incomes**, tribal communities, rural communities, coastal communities, communities with limited infrastructure and other communities traditionally underrepresented in public processes and adversely harmed by environmental and health hazards, including but not limited to seniors, youth and persons with disabilities.[54]

Further, the purpose and scope of the Climate Protection Program (CPP) laid out in OAR 340-273-0010(2) states:

> Climate change caused by anthropogenic greenhouse gas emissions has detrimental effects on the overall public welfare of the State of Oregon. Reducing greenhouse gas emissions and mitigating climate change will improve the overall public welfare of Oregon. In particular, reducing greenhouse gas emissions will improve the welfare of environmental justice communities.[55]

OAR 340-273-0010(2)(c) further addresses health impacts to environmental justice communities, stating:

> Environmental justice communities in Oregon are disproportionately burdened by air contamination, including through disproportionate risk of the impacts of climate change.[56]

While energy efficiency programs have the potential to reduce near-term costs, installing fossil fuel appliances into low-income homes makes it increasingly likely that low-income and energy burdened customers will be stranded on the gas system, left to cover the system's fixed costs as wealthier people leave due to their choice and economic ability to

[53] CUB/106 Wochele-Jenks/1.
[54] *Id.*
[55] OAR 340-273-0010.
[56] *Id.*

electrify. Similar to CUB's concerns around the necessity to eliminate Line Extension Allowances (LEAs), CUB is growing increasingly concerned that the Commission does not have a fuel switching policy in place to support the electrification of low-income customers who are already the least likely to be able to afford electrification—and who are the least responsible for climate change. Additionally, as of 2024, 15-20% of the energy assistance need of NWN customers was among renters, meaning these families also face even more barriers to making necessary electric upgrades to begin with.[57] While it is imperative to get to the root cause of low-income, high-usage households' energy insecurity and affordability struggles, our current approach is out of step with the State's environmental justice goals. Especially when we consider that these low-income energy efficiency programs at a minimum do not give qualifying low-income customers a choice of what fuel type appliance is installed. These customers are already captive customers of a monopoly utility. On top of this, they likely have had little to no control over what appliances are inside of the homes they move into due to their incomes. Instead, our current process amounts to the outdated and inequitable adage of "beggars can't be choosers." Essentially, it limits the autonomy of impacted families who need support by justifying their second-rate treatment.

Ensuring a fuel switching policy for low-income households is both a short term and a long-term affordability strategy for high-usage customers in particular. It is also aligned with Oregon's understanding of climate change and environmental justice. This issue warrants sincere attention and time from all relevant stakeholders in order to problem solve

[57] CUB/110 Wochele-Jenks/19.

the barriers as identified in UG 490 and UG 520, and any other barriers, for low-income and environmental justice communities' right to a just energy transition.[58]

Q. Does CUB have a particular recommendation related to the energy affordability concerns of low-income, high-usage households?

A. CUB is not suggesting we stop funding NWN's OLIEE program. At this time, we uplift these concerns to highlight the limitations of NWN continuing to raise rates without attention to both root cause affordability problems and energy equity and environmental justice principles for this group of customers. It also highlights opportunities for the Company to improve energy equity in a meaningful way. These are policies which are in the control of the utility to champion and enact. Further, focusing on energy burden as the sole metric of energy insecurity is limiting and cannot be relied upon alone, especially in the context of low-income customers with high-usage from energy inefficiencies.

Q. Nonetheless, does the record show that this proposed rate increase is affordable?

A. No. As discussed above, the record does not support NWN's conclusion the "overall 1.4% revenue requirement increase associated with the ARM is reasonable and would not compromise energy equity and affordability."

II. WRONGFUL DISCONNECTIONS IN NOVEMBER & DECEMBER 2025

Q. Please explain the temporary disconnection moratorium policy that was to be in place for at least half of November and all of December 2025.

A. In November 2025, NWN along with the other five Oregon Investor-Owned Utilities agreed to voluntarily implement additional protections for known vulnerable customers.

[58] Order No. 25-420 at 19-23.

NWN specifically agreed to pause all disconnections for its BDP customers and medical certificate customers, respectively. This was in response to Oregon Legislators[59] advocacy in docket UM 2211 on November 7, 2025. CUB has since learned that the Company intended to implement this for its Washington customers as well but failed to do so.[60]

Q. When did the temporary winter disconnection moratorium begin?

A. According to the Company, it was to begin on November 15th, 2025. Though this was not CUB's understanding. The Company told legislators on or before November 12th that it would be implementing this temporary pause. Senator Patterson put out a press release on November 12th stating the commitment that NWN made in this regard.[61] The discrepancy of why the Company planned for November 15th to begin this moratorium despite knowing that the information about the moratorium was publicized on November 12th through that press release and reported in at least one local news outlet, is unclear.[62] It is worth highlighting that November 15th of 2025 was a Saturday, and the Company is not allowed to administer disconnections on Fridays, Saturdays, or Sundays under regular Division 21 rules.[63] While it turns out that NWN did not implement this moratorium at all, it did implement a "holiday moratorium" where it did not disconnect customers the week of December 22 or December 31 through January 2.[64] This means customers still could have been disconnected on Monday, December 29th or Tuesday, December 30th.

[59] CUB/122 Wochele-Jenks/1-3.
[60] CUB/123 Wochele-Jenks/1-4.
[61] CUB/124 Wochele-Jenks/1-2.
[62] CUB/125 Wochele-Jenks/1.
[63] OAR 860-021-0320.
[64] CUB/123 Wochele-Jenks/1-4.

Q. Please explain what CUB discovered about the Company's failure to implement a promised voluntary, temporary winter disconnection moratorium for its known low-income and medically vulnerable customers.

A. On February 12th, when CUB was reviewing data from NWN's 2025 Q4 Energy Burden Metric Reporting (EMBR) in docket RO 16, we realized that there were a total of 352 BDP households disconnected in November (139 accounts) and December (213) of 2025.[65] Yet there was supposed to be a temporary winter moratorium in place for these customers for roughly half the month of November, and the entire month of December.[66] CUB immediately sent Data Requests (DRs) to the Company inquiring about this discrepancy, assuming it was a reporting error, and not that the Company had in fact gone through with hundreds of disconnections it was not supposed to.[67]

On Friday, February 19th, NWN's Vice President of Regulatory Affairs and Resource Planning contacted CUB's Executive Director, Bob Jenks, to inform him of the Company's error.[68] In response to CUB DR 31, the Company stated that it "discovered that we did not implement the voluntary temporary winter disconnect moratorium for bill discount programs as intended."[69] It further noted that "processes were in place to do so."[70] The mistake was made due to a "internal miscommunication."[71]

[65] CUB/108 Wochele-Jenks/4.
[66] *Id.*
[67] CUB/128 Wochele-Jenks/1-2.
[68] NWN's Vice President of Regulatory Affairs and Resource Planning also reached out to Oregon Public Utility Commission Chair Letha Tawney on or around the same date. *See* CUB/123 Wochele-Jenks/4.
[69] CUB/128 Wochele-Jenks/2. The moratorium was also supposed to be for medical certificate customers, but the Company did not disconnect any of those customers during this time despite its failure to otherwise implement the policy.
[70] CUB/123 Wochele-Jenks/2.
[71] *Id.*

Q. When exactly did the Company realize its error regarding not implementing the temporary winter disconnection moratorium?

A. The Company states that it was not CUB's DR 31-32 inquiring about the data reporting in RO 16 which uncovered the error, but that it realized the error upon its submission of the report into RO 16 on January 29, 2026.[72] It states it began researching the cause for the error at this time, but that CUB's February 12th, 2026 DRs 31-32 "further heightened the priority of finding the cause."[73]

Q. How were customer impacted?

A. CUB is still working through the impacted customer data provided by the Company at this time. What we can say is that the Company stated that the majority of impacted households were reconnected the same day or next day following their mistaken disconnection in November or December.[74] It is worth noting though that there were at least 20 households who were disconnected for 3-13 days, 12 families who were disconnected for two weeks or more, with a household who remained disconnected for 43 days who had to pay $572.67 to reconnect, another household who remained disconnected for 50 days who was only $54.73 past due and had to pay $50 to reconnect, another disconnected for 61 days who had to pay $714.52 to reconnect, and other disconnected for 78 days.[75] Additionally, there were 35 households who have not yet been reconnected.[76] We know that at least four of those households did not wish to be reconnected when the Company was able to reach them, and two of these four had moved residences.[77] For customers who were disconnected

[72] CUB/123 Wochele-Jenks/2.
[73] *Id.*
[74] CUB/123 Wochele-Jenks/3.
[75] CUB/129 Wochele-Jenks/Excel spreadsheet Tab 1.
[76] *Id.*
[77] CUB/123 Wochele-Jenks/3.

for amounts below $150, they were on pre-existing payment plans which lowers the threshold for disconnection to just $50, instead of $150.[78] Recall that a customer is expected to pay not only their current bill, but a portion of the payment plan on top of that, and once a customer misses two consecutive payments for the payment plan, they are removed from the plan and subject to being shut off by the Company.

There were at least nine households who were disconnected twice in 2025 and once in 2024, and one household who was disconnected three times in 2024 and four times in 2025.[79] There were eight households who were disconnected again since they were wrongfully disconnected in November or December.[80]

Q. How many customers were impacted?

A. There were 198 Oregon households impacted by the Company's error and 16 Washington households.[81]According to the Company's records of those enrolled in the BDP, there were 603 people impacted by this error.[82]

Q. Can CUB explain the discrepancy in numbers from Docket RO 16 and the discovery process in this case?

A. Yes. NWN describes the reason for the discrepancy is due to the fact that the Company counts those customers who were, at the time of their disconnection not on the BDP, but who enrolled in the BDP following their reconnection, as BDP households who

[78] CUB/129 Wochele-Jenks/Excel spreadsheet Tab 1.
[79] *Id.*
[80] *Id.*
[81] CUB/132 Wochele-Jenks/1-2.
[82] When enrolling in the Bill Discount Program a family must also self-attest their household size to determine eligibility. CUB asked the Company to disclose the household sizes of the impacted households. *See* CUB/129 Wochele-Jenks/Tab 1.

experienced disconnection in a single month.[83] Customers who were qualified, but not yet enrolled in the BDP, would not have been protected from disconnection even if the Company had correctly implemented the temporary moratorium. However, their BDP enrollment following their November or December disconnection would have protected them from a future disconnection taking place during the moratorium, if the moratorium had been enacted.

Q. How has the Company handled its mistake to date?

A. The Company took three actions:

1. Refunded all impacted customer accounts the fees associated with the disconnection.[84]
2. Attempted contact or made contact with those customers who still remained disconnected in February following a November or December disconnection.[85]
3. Credited $150 to all impacted customer accounts—those whose accounts were still open.[86]

Q. How did the Company ascertain that a $150 bill credit was a reasonable amount given its error?

A. In a meeting with the Company, Company representatives told CUB that $150 is the amount past due that triggers a disconnection.

Q. How did the Company contact its customers when it realized this error?

A. On February 19th, three weeks after the Company states it first realized its error, and one week after CUB submitted DRs 31-32 regarding the error, it reached out to the 21 Oregon

[83] CUB/132 Wochele-Jenks/1-2; *See* also CUB/ 129 Wochele-Jenks.
[84] CUB/123 Wochele-Jenks/3.
[85] *Id.* at 3.
[86] *Id.* at 4.

households who still remained disconnected from their November or December mistaken disconnect, to inform these customers that they could be reconnected for no charge.[87] NWN was able to reach five of the 21 households.

Of those 5 reachable impacted households:

- 2 impacted households told the Company they had moved;
- 2 impacted households said they wanted their service to remain off and their account closed; and
- 1 impacted household elected to have their gas turned back on that day—suggesting this family had been navigating life without access to gas for at least two months in the middle of winter.

Of the 16 impacted households who the Company could not reach, those who remained otherwise disconnected since a November or December disconnection:

- 6 impacted households had non-working phone numbers; and
- 10 impacted households the Company left a voicemail alerting them to the possibility of reconnection with no charge.

Q. Did NWN reach out to those customers who had already reconnected to explain the error in the disconnection?

A. The record does not show that NWN communicated this. Instead, as discussed below, NWN has applied a bill credit.

[87] CUB/123 Wochele-Jenks/3.

Q. Did the Company offer impacted households any form of compensation for their error and the ensuing hardship these families likely navigated due to the winter disconnection?

A. On February 27, 2026, one month and one day after the Company says it first identified its error, and nearly two months since the moratorium should have ended, NWN applied a $150 bill credit for all impacted customers. The Company states that the bill credit will appear on the customer's next bill as a line item with a bill message that reads, "The $150 credit on this bill corrects a service disconnection error related to a temporary pause in your service last year. This courtesy will help lower your bill."[88] In the instance of impacted customers who have closed accounts, such as the four households who indicated they had either moved or wanted their account to remain closed, they would be issued a "corrected final bill that includes the credit, which will reduce the final balance and may result in a refund check."[89] Note that the households who have moved or any who have been evicted, would need to have mail forwarding set up to receive any refund check, as well as a new stable address to receive mail.

Q. Does CUB believe this message on the bill is sufficient to explain what happened?

A. No, the explanation provided by the Company with the bill credit does not paint a clear picture for impacted customers about how, when, and why they were impacted.

Q. Does the Company expect ratepayers to cover these bill credits?

A. NW Natural told CUB's Executive Director in a phone conversation on February 19th, 2025, that the Company/ its shareholders would cover the cost of the bill credits. To date

[88] CUB/123 Wochele-Jenks/4.
[89] *Id.*

this is not in writing in the discovery process to CUB's knowledge. Nor has CUB seen any deferrals for these bill credits.

Q. What does CUB think of the actions the Company has taken to date to remedy its error?

A. CUB is glad the Company took action to both attempt reconnection for those impacted households who perhaps still remained disconnected after months of being disconnected, and for all impacted households to receive a bill credit, as well as refunds of associated fees. However, CUB expressed to the Company previously that we do not think the bill credit goes far enough for impacted families, especially considering the families who remained disconnected for extended periods of time, as well as those who were perhaps evicted as an outcome of their disconnection. CUB is waiting for additional data coming from the Company to better understand the specific circumstances of the impacted households. Once CUB receives that information and is able to analyze it, we may have additional recommendations. We greatly appreciate the Company's efforts to expedite information to us on this crucial matter.

Q. Is CUB aware of any other instances of Company errors that are impacting its customers?

A. Yes. Advocates in Washington alerted CUB to an ongoing issue with NWN improperly charging fees to customers in Washington. Some customers in Washington are eligible to receive waived fees, but the Company's process for waiving these fees is done manually and is subject to human error.[90] Advocates have noted that there are customers who are still charged these fees when they should not be.[91] This has required the Company to go back

[90] CUB/126 Wochele-Jenks/40.
[91] *Id.*

each month and reimburse impacted customers those fees. Advocates have expressed frustration around this and are consistently making efforts to verify that NWN is indeed reimbursing these fees. This raises concerns for CUB that the new waived fees coming out of the updated Division 21 rules from Oregon Docket AR 671, will also be subject to this manual fee reversal process.[92]

Q. Is CUB seeking any additional action in this docket to address the Company's mistake and its impact on the identified low-income disconnected households?

A. Yes. At the very least, CUB is proposing a management disallowance. NWN committed to a moratorium on disconnecting low-income customers. It promised legislators that it would not disconnect these customers. CUB recommends a management disallowance of $10,000 for each household incorrectly shut off. This means $10,000 x 198 Oregon households, or $1,980,000.

CUB is also concerned that if it were not for the Company needing to comply with disconnection data reporting through Docket RO 16, this error would not have been caught by the Company or anyone else, and customers would not have received any compensation or acknowledgement of the Company's mistake. We are interested in the Company being subject to an audit, investigation, or something similar as it relates to both its customer service department and Customer Information Systems. For example, the Commission has undertaken a similar process in UM 1750 when it received customer complaints on NWN's Weather Adjusted Rate Mechanism (WARM) end of year billing true-ups. In that docket, the Commission opened an investigation pursuant to ORS 756.515 into NWN's WARM

[92] *See* CUB and Energy Justice Advocate comments regarding compliance and accountability for Oregon utilities regarding the Division 21 Disconnection Protections, CUB/127 Wochele-Jenks/1-4.

issues related to the 2014-15 winter season.[93] Likewise, the Commission has instructed utilities to submit a Performance Plan after receiving customer complaints calling into question whether the utility was providing safe and adequate services.[94] CUB is interested in accountability to ensure something like this does not happen again. We reserve the right to make additional recommendations through UG 527 as it relates to this issue, if it becomes the case that we cannot come to agreement with the Company outside of this space.

III. ALTERNATIVE RATE MECHANISMS: AN ARM AND A LEG

Q. How is NWN asking to recover these costs?

A. NWN filed for rate recovery under what it claims is an "Alternative Rate Mechanism" or ARM. NWN states the application for an ARM "is to recover the costs of a limited subset of capital additions through a new base rate tariff, Schedule 123."[95]

Q. What is an Alternative Rate Mechanism (ARM)?

A. Beginning in 2025, PGE filed two ARMs to allow the utility cost recovery for a limited number of issues. As discussed below, PGE filed the ARMs after entering into an MOU that set the ARM's parameters. Subsequently, NWN filed this ARM. To date, the two utilities have used the ARMs to define what is in and what is out for consideration, while avoiding a comprehensive look at a utility's costs, revenues, and investments. Additionally, by filing ARMS they ensure the protection of their authorized ROE which is not reviewed in an ARM. Relatedly, NWN also avoided conducting a corresponding Cumulative

[93] Order No. 15-264.
[94] *See e.g.,* Order No. 35-371.
[95] NWN OPUC Advice No. 25-25, at 1.

Economic Impact Assessment for its residential customer class, which are now required for all rate cases where ROE is under review, per HB 3179 (2025), the FAIR Energy Act.[96]

Indeed, there is no definition of an ARM in Oregon ratemaking. ARMs have been used as an alternative to a General Rate Case, and while they might be considered a form of single-issue ratemaking in principle, these three ARM filings test whether that is true. Relatedly, it is not clear what can be included in an ARM. For example, could a utility file an ARM and include all the new capital investments it has made? Could an electric utility include generation, transmission, and distribution investment? NWN's ARM is a smorgasbord for recovery, which includes Mist, IT investments unrelated to Mist, other discrete investments with a cost above $1 million, and projects it labels "public work" projects.[97] Could a utility include some O&M costs? The ARMs that have been filed by PGE and NWN have not included the rate of return (ROR). Is that what makes a rate case an ARM?

Q. What are CUB's views regarding the recent utility use of Alternative Rate Mechanisms (ARMs)?

A. In addition to our general concerns about lack of clarity on what exactly an ARM is and is not, including the current lack of limits around ARMs, we are concerned at least about the following as it relates to ARMs:

1. Utilities shifting risk to customers;
2. The inability for a comprehensive review of a utility's costs by stakeholders;
3. The utility using ARMs to protect its ROE;
4. The utility alone determining the limits to these cases; and

[96] CUB/121 Wochele-Jenks/1.
[97] *See* NWN/100 Kravitz-Walker/2.

5. Utilities' ability to rely on ARMs with no set limits during the interim Multi-Year Rate Plan (MRP) period.

Oregon utilities already enjoy a plethora of mechanisms to raise rates. Yet, somehow an unusual, broad, open-ended mechanism has been introduced. We generally do not support the use of ARMs, especially when there are not clear, pre-defined guardrails to contain them and to protect customers. This recent mutation of single-issue ratemaking is no better a process for customers than previous single-issue cases, and it is far outside the spirit of the FAIR Energy Act. CUB's negative experience and growing concerns while navigating an increasing number of single-issue cases contributed to the impetus for the creation of the FAIR Energy Act in the first place. Yet, in response to the legislation becoming law, ARMs seem to be one way utilities are responding to it.

Through utilities' use of ARMs, like other single-issue rate cases, other parties to the case lose the ability to look holistically at a utilities' overall costs, resulting in less oversight and more risk for customers. The unchecked use of ARMs will only enable a utility to continue to reduce its own risk, shifting it to its customers, while also protecting, or staving off a lower ROE in response to declining ROEs of peer utilities or the utility's multiple opportunities for cost recovery. Following Order 24-454, utilities are no doubt keenly aware of the recent precedent of lowering ROE to recognize that frequent rate cases reduce risk and reduce regulatory lag.[98] Could a utility use an ARM to lower its risk by having frequent rate cases with limited regulatory lag, but avoid any consideration of adjusting the ROE to account for the lower risk?

[98] Order 24-454 at 12.

Q. Can CUB describe its concerns related to NW Natural defining the limits of this case?

A. Yes. There currently are no agreed upon limits in this case. Instead, NWN has attempted to define the terms of what is being considered. It chose what cost increases to include and what offsets to those cost increases to include. But it is important to recognize that there is no basis for NWN to define the limitation on CUB's or other party's testimony and evidence. And we do not believe that companies in these cases can limit what evidence or issues CUB and other parties put before the Commission.

To illustrate this concern, in this case NWN is adding three new rate base additions to Mist but has not included updating depreciation for all Mist assets as an offset. If the Company is asking the Commission to add Mist replacement costs to rate base, NWN should correspondingly update depreciation to ensure that customers are not paying for an inflated rate base. Thus, CUB is proposing to update the depreciation of all assets associated with Mist. While this is not an offset that NWN has defined as part of this ARM it is appropriate and necessary. See Witnesses Jenks' testimony in CUB 200 for further discussion of the Mist asset replacements.

Q. What are CUB's views on the use of a multi-party Memorandum of Understanding (MOU) in a utility's use of ARMs to set limits at the outset of a case?

A. In the PGE ARM (UE 459), there was a MOU where parties negotiated what would be considered and what would be off-limits.[99] This included binding and non-binding understandings.[100] One of the intentions of the MOU was to limit the scope of costs while

[99] CUB/107 Wochele-Jenks/28-33.
[100] *Id.*

avoiding another General Rate Case (GRC).[101] Following the decision in UE 435, the MOU was quickly executed. It was not perfect, but it was likely better than not having one as it placed guardrails on recovery. As CUB noted in UE 459 and expressed in the MOU itself, CUB's signatory to the MOU did not represent an agreement "on the need or the appropriateness of a [...] Alternative Recovery Mechanism."[102] The MOU in UE 459 was not meant to set any sort of precedent for future reliance on ARMs or other such mechanisms. Despite that, in UG 527, and in the absence of an MOU, NWN has proposed not just an ARM, but a leg. PGE's ARM was limited to distribution investments, NWN's ARM covers investments in storage, IT, public work projects, and other investments it calls discrete investments. Overall, CUB is interested in the ways an MOU can set guardrails to an ARM if there are otherwise none established by the Commission.

Q. What does CUB think about how the use of unchecked ARMs will interfere with stakeholders working toward implementing Multi-Year Rate Plans from the 2025 FAIR Energy Act (HB 3179)?

CUB is concerned about the use of ARMs becoming a new normal, especially as we work towards implementing Multi-Year Rate Plans (MRPs) in Oregon. Thus, not only is the use of unchecked ARMs a real concern, but CUB is concerned about the capacity of stakeholders to take on the labor required to be successful in the creation of MRPs for Oregon if we must also navigate multiple unchecked ARMs. The Pacific Northwest National Laboratory (PNNL) noted in its recent analysis of "Oregon's Existing Utility Rates and Related Mechanisms"[103] the following:

[101] *Id.*
[102] CUB/105 Wochele-Jenks/24.
[103] CUB/113 Wochele-Jenks/21.

> Rate cases, power/gas costs and true-up proceedings, other revenue adjustment requests, and other schedules, adders, and automatic adjustment clauses collectively represent a meaningful administrative workload for OPUC staff and others.[104]

To date there are no guardrails in place for ARMs for the interim period, though stakeholders are working through that process in Docket AR 677.[105] Importantly, it remains to be seen if the Commission will be approving interim guidelines in rules or if utility stakeholders will be expected to abide by some sort of an honor system through Docket AR 677. Indeed, as this ARM is being considered, NWN may well be preparing to file a new ARM next December.

Q. Has NWN indicated the statutory authority under which it can seek this rate increase?

A. No. Normally when a utility files for a rate increase, the utility indicates the statute that permits such a filing. NWN, however, has not indicated what statute, rule, or regulation permits this ARM filing. Nor has NWN entered into a Memorandum of Understanding (MOU) with the parties agreeing to its filing of this ARM. In other words, it's not clear there is any authority that would allow NWN to change rates through this ARM.

Q. NWN says it is filing this ARM because of FAIR's prohibition on residential rate increases during winter months (November 1 to March 31) and extension of the rate suspension period to 11 months in total.[106] Do these new restrictions justify this ARM?

A. No. To begin, the moratorium on winter rate increases does not then require an ARM filing. HB 3179 Section 3(7) only states "[a]ny increase in residential rates may not take effect

[104] *Id.* at 47.
[105] CUB/103 Wochele-Jenks/1-5.
[106] NWN/100 Kravitz-Walker/7.

from November 1 to March 31." This winter moratorium on rate increases was a direct response to dramatic and back-to-back rate increases in the middle of winter. Such practice was harmful to residential ratepayers particularly during winter storms. Both of these events – the rate hike and the extreme cold weather – significantly increased customer heating bills. As a result, the legislature placed a restriction on winter rate increases, but this was not an invitation for the utility to turn around and file for cost recovery in every other month of the year. Likewise, extending rate cases from 10 to 11 months gives the Commission and parties one additional month to review the cases. It recognized the capacity constraints of the Commission, particularly when multiple utilities file rate cases with nearly identical schedules. It is absurd to think that this month-addition would be to encourage a flood of rate recovery filings outside of a GRC.

Q. NWN then says that the reason for the ARM is because it did not file for a multi-year rate plan in 2025, and given the passage of HB 3179 (2025) it, then forwent filing a "traditional rate case", and instead filed an ARM.[107] Does this reason justify the ARM?

A. Again no. To the best of CUB's knowledge, there have not been multi-year rate cases since the use of the Alternative Form of Regulation (AFOR) statute in the 1990s and yet that did not lead to annual rate case or ARMs. In UG 490, the Company requested the Commission direct it to file a multi-year rate plan in lieu of its next general rate case.[108] Staff, CUB, and AWEC all opposed NWN's request.[109] The Commission declined NW Natural's request pointing to an insufficient record as the basis with the reminder that a GRC is not an

[107] NWN/100 Kravitz-Walker/7.
[108] Order No. 24-359 at 47.
[109] *Id.* at 48

appropriate place to seek an advisory opinion.[110] If the Company was going to file a multi-year plan, it would need to "engage in a robust stakeholder process ahead of the filing to gather feedback on the design and all elements of the framework, as well as any stakeholder concerns."[111] The Commission further expected that any such proposal would include "detailed discussion regarding meaningful performance metrics, how the plan results in just and reasonable rates, and any customer protections or benefits." [112] To CUB's knowledge, while NWN participated in the back-and-forth of the FAIR Energy Act negotiations prior to enactment, NWN did not separately engage stakeholders on the framework of a multi-year plan ahead of its UG 520 filing. If it had filed UG 520 as a multi-year plan for recovery, it's likely the Commission would have again declined to adopt the plan based on the direction in the UG 490 Order. What this means is that there was no multi-year rate plan option for NWN in 2025 to choose over the traditional rate case. Accordingly, the Commission should find this justification for the ARM is not persuasive.

Q. NWN also says it considered filing a GRC with a rate effective date of April 1, 2027 "combined with a deferral to address the delay in cost recovery" but instead opted for this ARM. [113] Does this reason justify the ARM?

A. Still no. Recall that NWN filed this ARM less than a month after its rate effective date in UG 520. This ARM is not limited to a few discrete issues; rather, it covers a variety of cost recovery and allocation changes similar to a GRC. But if NWN had filed this as a GRC, presumably with the opportunity to adjust its ROE, then there was the real risk the Commission could have lowered the ROE as it did in UE 435. In this way NWN has used

[110] *Id.*
[111] *Id.* at 50.
[112] *Id.*
[113] NWN/100 Kravitz-Walker/8.

the ARM as insurance to avoid a lowered ROE while still requesting to recover costs to avoid regulatory lag. In short, NWN's filing is a wolf in sheep's clothing. The scope of NWN's ARM is in effect a GRC but offers a cost of capital protection a GRC would not. The benefit here is to NWN.

On the second point, HB 3179 (2025) amended ORS 757.210 to add two new subsections 6 and 7. Although not yet codified in ORS 757.210(7), the Commission recognized that ORS 757.210(7) will state "[a]ny increase in residential rates may not take effect from November 1 to March 31."[114] Section 7 does not explicitly provide for a deferral of costs. That said, the Commission recently commented how the winter rate increase moratorium will be implemented in Order No. 25-505 on PacifiCorp's RAC filing. In considering the mechanics of the FAIR Energy Act and its winter rate increase moratorium, the Commission explained:

> We generally do not believe residential rate payers shouldering additional interest is consistent with the FAIR Act's intent, especially in a mechanism designed to reduce the utility's regulatory lag in capital cost recovery. However, how to accomplish this in light of the statute related to the RAC remains to be settled. Similarly, outside of legislatively mandated single-issue recovery processes, utilities control most, if not all, aspects of their capital planning and decisions to seek single-issue capital cost recovery filings. In those cases, we encourage the company to consider changes to the timing of its future filings given the residential winter rate increase mortarium.[115]

[114] *In the Matter of THE PUBLIC UTILITY COMMISSION OF OREGON Investigation into the Purchased Gas Adjustment (PGA) Mechanism Used by Oregon's Three Local Distribution Companies,* Docket No, UM 1286, Ruling establishing deadlines (Aug. 11, 2025).
[115] Order No. 25-505 at 15.

Thus, the Commission has signaled that deferrals for capital cost recovery during the winter months, as NWN's states it contemplated as an alternative to this ARM, are inconsistent with the FAIR Energy Act's intent and inappropriate when utilities control capital planning.

It is important to recognize that while NWN may desire an opportunity to eliminate any delay in cost recovery, it is that delay, regulatory lag, which provides an incentive for a utility to control costs. NWN's frequent rate cases have eliminated most regulatory lag, but the consequences may be related to the explosion of cost increases in non-gas (margin) costs that we discussed above with CUB Figure 2.

This contrasts with a power cost filing or a purchased gas adjustment. Recall that, for a capital project that the utility will earn a return on for decades, so it can take on regulatory lag. In contrast, a power cost case is an annual filing and the company is not earning a return. In PGE's 2026 AUT, the Commission commented on the timing of the residential rate increase in the first year after the FAIR Energy Act became effective. "Given the nature of the interaction between the FAIR Energy Act and annual cost reviews such as this AUT, we anticipate longer-term changes in the future through additional processes."[116] In this instance the deferral was a stipulated measure to address power costs while FAIR was being implemented at the PUC.

[116] Order No. 25-439 at 4.

As noted above, Section 7 does not explicitly provide for a deferral of costs during the winter. Nor has NWN indicated which portion of the FAIR Energy Act they are otherwise looking to for this deferral. Where it is not required by law, whether or not to grant a deferral is up to the Commission's discretion. HB 3179 (2025), the FAIR Energy Act, specifically mentions two instances when the PUC must review and *consider* deferred accounting, Section 3 and Section 4. The first is in Section 3, when the Commission determines it is necessary to mitigate "an increase in residential customer rates if the increase is of such magnitude that, if applied at the higher rate or all at one time, the increase would affect the ability of residential customers to maintain adequate utility service," In other words, a GRC, and specifically for the amounts at issue.[117] In the second instance, Section 4 (HB 3179(4)) only requires the Commission to *consider* a deferral filing in cases where the ROE is subject to review or modification, and whether to grant that review is still up to the Commission. Section 4 of FAIR is a temporary section intended to apply as utilities transition from historical general rate case schedules to multi-year rate schedules.[118] In sum, nothing in the FAIR Energy Act guarantees a deferral will be granted.

Q. Does CUB believe the Commission can reject the consideration of an ARM?

A. Yes. While neither of us are attorneys, CUB hopes that the Commission can do so. The Commission ruled in UE 435 that it could not reject a GRC.[119] But the Commission has found that deferrals and SCRMs are discretionary and also declined to adopt the Seaside tracker in UE 435.[120] Because a utility is not claiming that it needs the recovery associated

[117] HB 3179, Sec. 3(6).
[118] *See* HB 3179(5) that repeals section 4 when the Commission establishes permanent rules for Section 7, or Jan. 2, 2027, whichever comes first.
[119] Order No. 24-110 at 3-4.
[120] Order No. 24-454 at 38.

with an ARM to ensure shareholders are compensated, it seems like an ARM is closer to a deferral and the Commission would have discretion. But as it stands, it appears there is nothing yet stopping NWN from coming back with another ARM within a month of the final order in UG 527. There is a real need for the Commission to identify what ARMs are meant to accomplish and to place limitations on ARMs.

While the regulatory process is often described as a balancing act between the interests of shareholders and customers, it is worth recognizing that Oregon law centers the customer. The first two sentences of the PUC's General Powers make clear who is supposed to be central to utility regulation in Oregon:

> In addition to the powers and duties now or hereafter transferred to or vested in the Public Utility Commission, the commission shall represent the customers of any public utility or telecommunications utility and the public generally in all controversies respecting rates, valuations, service and all matters of which the commission has jurisdiction. In respect thereof the commission shall make use of the jurisdiction and powers of the office to protect such customers, and the public generally, from unjust and unreasonable exactions and practices and to obtain for them adequate service at fair and reasonable rates.[121]

Centering the customer means rather than focusing on the utility's desire for cost recovery without regulatory lag, we should be addressing the problems customers are experiencing – things like high rates of disconnections, rate levels that are increasingly unaffordable, incentives to control capital spending, the growing risks and inequities from stranded gas assets, and outstanding arrearages. This ARM does not address these problems.

[121] ORS 756.040.

Q. Does NWN have alternative means for recovery of these costs outside of the ARM?

A. Yes. The issue here is not whether the Company can get cost recovery; the question is whether the Company should allow for regulatory lag by controlling its costs. NWN filed UG 221 in 2011 and did not file another rate case until UG 344 in 2017.[122] The Company had capital investments it made during this time but accepted regulatory lag and worked to reduce costs. This was not unusual. The PUC's website has a page called key cases which list the General Rate Cases for each utility. It is a recent phenomenon that NWN has ceased controlling costs and now needs annual rate adjustments and the elimination of nearly all regulatory lag.

Q. Should the Commission apply an earnings test to ARMs?

A. Yes. First, we note that the Commission recently imposed an earnings test in both PGE's Seaside ARM and to PGE's Distribution System Plan (DSP) ARM (UE 455 and UE 459) in order to ensure fair and reasonable rates.[123] In doing so the Commission has affirmed its "application of an earnings test and accompanying deferral is squarely within the Commission's broad legal powers in accordance with ORS 756.040."[124] When PGE challenged the imposition of an earnings test in UE 455, the Commission upheld its decision explaining:

> Because this docket is a single-issue proceeding with limited review of PGE's rate base, costs, and earnings, we find that the unconstrained cost recovery for the Seaside Project may result in unjust and unreasonable rates. For that reason, we allow PGE to place its Seaside Project in rates but include an earnings test on the associated revenue collected to constrain recovery reflective of the company's overall earnings to help ensure just and

[122] *See* Order No. 12-437 at 1, Order No. 18-419 at 2.
[123] *See* Order No. 25-417 at 13-14 (finding "an earnings test will serve as an important check to ensure that this rate adjustment mechanism does not result in additional cost recovery when the company is otherwise able to achieve its authorized [rate of return]."); *see also* Order No. 26-025 (supplementing and upholding Order No. 25-417); Order No. 26-074 at 6-7.
[124] Order No. 26-025 at 2.

> reasonable rates for customers. This serves to avoid unfair overearning through pursuit of single-issue ratemaking.[125]

Thus, CUB believes that the Commission should apply an earnings test to this case and that earnings test should reflect the frequency of NWN rate cases by being established at 40 basis points below its authorized ROE. The Company should only be allowed to adjust rates out of this case up to 40 basis points below its authorized ROE.

Q. In PGE's recent ARMS, UE 455 and UE 459, the Commission set the earnings test at the authorized ROE, why is CUB recommending an earnings test of 40 basis points below the AROE for NWN's ARM?

A. PGE was starting from a point of having a reduced ROE from UE 435. Its ROE was reduced from 9.5 to 9.34 to reflect the Company's reduced risk due to the frequency of its ratecases. NWN is using an ARM to avoid its third straight ROE challenge, which could have led the PUC to cut the ROE because frequent rate cases reduce the utility's risk. Between the ROE reduction in UE 435 and the earning tests PGE is facing a 41 basis point reduction from their ROE before it was adjusted to account for frequent rate cases. Accordingly, an earnings test set at 40 basis points below is consistent with these Commission orders.

Q. What has the Commission said previously about the limits of single-issue ratemaking or ARMs that support CUB's request for an earnings test?

A. Most recently, in Order 26-025, which the Commission reiterated in Order 26-074, the Commission stated:

> The Commission prefers to set rates in a general rate proceeding, where all of the utilities' costs, investments, and earnings can be evaluated to ensure

[125] Order No. 26-025 at 3.

> that rates are just and reasonable. Single-issue ratemaking proceedings are allowed but are limited. As we noted in our prior order, a single-issue rate case precludes a full examination of the utility's overall costs and profits, and could result in a rate adjustment that allows a utility additional cost recovery when the company is otherwise earning its authorized rate of return.[126]

Further, in the Commission recent Order 26-074 on PGE's DSP ARM in UE 459, the Commission required an earnings test in order to:

> balance risk between customers and PGE and to ensure that rates remain just and reasonable […] we find the limited review afforded to PGE's rate base, costs and earnings could result in unjust and unreasonable rates.[127]

In UE 458, PGE's 2024 Winter Storm Deferral, the Commission also ordered an earnings test stating:

> Deferrals, such as the one at issue here, are intended to provide for a range of outcomes and are not intended to guarantee recovery at the company's authorized ROE. An earnings test will allow us to ensure that resulting rates are fair, just, and reasonable.[128]

Q. Are there additional levers the Commission could consider pulling as it relates to ARMs?

A. Yes. Beyond an earnings test, the Commission should consider the following:

- Rejecting additional ARMs while stakeholders are designing a new Multi-Year Rate Plan (MRP) process. With multi-year ratemaking, ARMs should not be necessary, but to design a good process for multi-year ratemaking, stakeholders

[126] Order No. 26-074 at 6.
[127] *Id.*
[128] Order No. 26-077 at 10.

cannot afford to spend large amounts of effort evaluating utility requests for ARMs.

- Rejecting the use of serial ARMs where the utility files a new ARM soon after one is completed.
- Identify the circumstances where a utility's ROE should be adjusted to account for the lower risk associated with too many rate adjustments.
- Permitting ARMs only where there is an identifiable and definitive risk to customers not merely when the utility is seeking recovery.

The Commission placing limits on ARMs will be increasingly important once stakeholders come to alignment in AR 677 about the interim MRP exceptions process. If a utility is out of step with the agreed upon exceptions process guidelines and determination process, the Commission will need to act to protect customers and ensure utility accountability. Otherwise, the labor expended by Staff and other stakeholders like CUB in AR 677 and beyond, is for naught.

IV. CONCLUSION

Q. Please summarize your recommendations.

A. Note that this is a summary of our recommendation. The summary should not be read in isolation but with our testimony as a whole.

- Require a management disallowance of $10,000 for each of the 198 impacted Oregon households who were wrongly disconnected in November and December 2025 due to the Company's oversight.
- Require an earnings test at 40 basis points below the ROE for any rate change associated with this filing.

- Establish limitations on utility filing ARMs in the future.

Q. Does this conclude your testimony?

A. Yes.

WITNESS QUALIFICATIONS STATEMENT

NAME: Sarah Wochele

EMPLOYER: Oregon Citizens' Utility Board (CUB)

TITLE: Equity Analyst & Advocate

ADDRESS: 610 SW Broadway, Suite 400 Portland, OR 97205

EDUCATION: Montgomery County Community College
Associate of Science in Psychology
Blue Bell, PA

Bucknell University
Bachelor of Arts in Psychology
Lewisburg, PA

University of Denver
Master of Social Work
Denver, CO

EXPERIENCE: Employed by Oregon Citizens' Utility Board (CUB) since January 2024. Work within the regulatory and legislative spaces, with a focus on the equity and environmental justice implications of energy utility policy and regulation. Co-led legislative efforts to draft, negotiate and pass HB 3546 (the POWER Act) and HB 3179 (the FAIR Energy Act) in 2025. Consulted on UE 426, UG 490, UG 519, UG 520, UGE 525 and UM 2377. Provided testimony in UE 433, UE 435, UE 459 and UG 527. Engaged collaboratively alongside EJ advocates and provided a multitude of comments in UM 2211, AR 667, AR 668, AR 670 and AR 671. Additionally, collaborated with energy advocates in a multitude of comments in implementing the FAIR Energy Act – HB 3179 (2025), in AR 676, AR 677, AR 678, and UM 2405. Worked from micro to macro levels in collaboration with individuals and groups who are facing various levels of injustices that impact their well-being. Served as an agent of the attorney in "criminal" defense cases at Colorado's Office of Alternative Defense Counsel, worked as a community organizer and engaged in legislative advocacy with Environmental Justice communities on the frontlines of environmental injustices, and conducted energy policy research at Colorado State University's Center for the New Energy Economy (CNEE). Co-authored the 2021 peer reviewed article, *"Environmental Justice and Black Lives Matter: Critical Reflection and Advocacy for Social Work in the United States."*

WITNESS QUALIFICATION STATEMENT

NAME: Bob Jenks

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ADDRESS: 610 SW Broadway, Suite 400
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EDUCATION: Bachelor of Science, Economics
Willamette University, Salem, OR

EXPERIENCE: Provided testimony or comments in a variety of OPUC dockets, including UE 88, UE 92, UM 903, UM 918, UE 102, UP 168, UT 125, UT 141, UE 115, UE 116, UE 137, UE 139, UE 161, UE 165, UE 167, UE 170, UE 172, UE 173, UE 207, UE 208, UE 210, UE 233, UE 246, UE 283, UG 152, UM 995, UM 1050, UM 1071, UM 1147, UM 1121, UM 1206, UM 1209, UM 1355, UM 1635, UM 1633, and UM 1654. Participated in the development of a variety of Least Cost Plans and PUC Settlement Conferences. Provided testimony to Oregon Legislative Committees on consumer issues relating to energy and telecommunications. Lobbied the Oregon Congressional delegation on behalf of CUB and the National Association of State Utility Consumer Advocates.

Between 1982 and 1991, worked for the Oregon State Public Interest Research Group, the Massachusetts Public Interest Research Group, and the Fund for Public Interest Research on a variety of public policy issues.

MEMBERSHIP: National Association of State Utility Consumer Advocates
Board of Directors, OSPIRG Citizen Lobby
Telecommunications Policy Committee, Consumer Federation of America
Electricity Policy Committee, Consumer Federation of America
Board of Directors (Public Interest Representative), NEEA

Oregon Public Utility Commission

AR 677 Rulemaking General Rate Revisions HB 3179

Staff Transition Period Concept

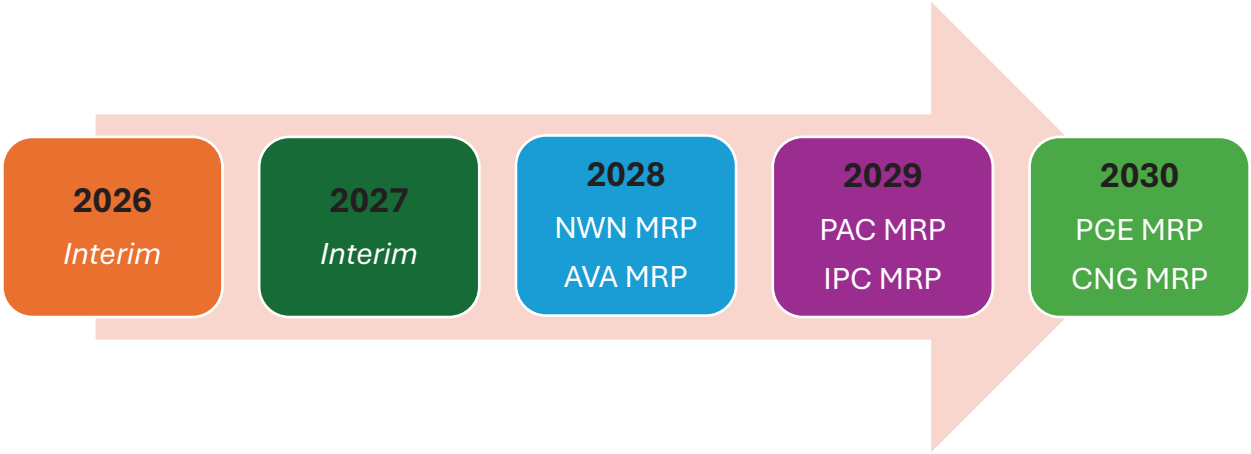
In the Matter of Rulemaking to Establish General Rate Revisions Filing Schedule and Exemption Process (HB 3179 Implementation).

Purpose

This straw proposal provides draft concepts for the transition period between now and each utility's first Multi-Year Rate Plan (MRP) under HB 3179. The objective is to clarify how existing ratemaking tools will be evaluated during the transition period and ensure that actions taken before 2029 do not undermine implementation of the MRP framework. This document is intended to inform stakeholder discussion and further refinement.

MRP Filing Schedule

Staff's proposed MRP filing schedule for inaugural utility MRPs is intended to create the certainty the utilities and stakeholders need to adequately plan. It provides a starting point for discussion and subject to change. At this stage, Staff's proposal sought to consider utilities' last GRC effective date, cumulative rate increases, utility size and service territory, and the proposed transition cost recovery process.



Transition Concepts

Staff's vision for cost recovery during the transition periods focuses on a limited number of narrowly scoped general rate cases (GRC) and discourages the use of new limited scope cost recovery mechanisms, such as alternative rate mechanisms (ARMs) and deferred accounting. Staff also responds to the concept of indexing approaches during the transition period.

Principles

Staff's concept is intended to preserve as much bandwidth as possible for the development of the MRP framework and to facilitate a transition that is transparent, predictable, and cost-contained. This phase is distinct from the term *between* utility MRPs once the framework has been established.

During the transition period, utilities will continue to make investments in energy resources and infrastructure, face inflationary pressures, incur non-discretionary costs (e.g., public works projects), and may make capital investments with short depreciable lives (e.g., software). Staff also recognizes that utilities with later MRP filing dates may have additional considerations and that there is a necessary balance between regulatory lag and rate shock. Staff's transition period concepts attempts to reflect these realities, the affordability and energy burden experience of customers, and the need to focus as much bandwidth as possible on MRP framework development. Therefore, Staff's proposal is guided by the following principles:

1. Balance affordability, financial stability, and administrative capacity.
2. Focus on targeted, high priority, and disciplined costs.
3. Provide clear expectations that enhance predictability and help utilities plan to avoid under recovery.

Transition Period Capital (ARMs)

With the two exceptions noted below, Staff does not contemplate the use of new ARMs during the transition period. Capital trackers or formula-like recovery mechanisms can reduce cost containment incentives, shift risk to customers, and unnecessarily complicate the transition to MRPs without the structural safeguards contemplated under HB 3179.

Staff's concept contemplates implementation of an ARM if the utility demonstrates:

- A single cost or cost category is included,
- The Company will not file a GRC during the transition period,
- The scope and timing of the filing is made such that it is responsive to Staff and stakeholder bandwidth, and
- Delayed cost recovery would materially impair access to capital, or
- The Company achieved a Return on Equity greater than 250 basis points lower than their most recently approved Authorized Return on Equity.

Any utility that determines it necessary to file for recovery via an ARM or tracker-like mechanism is expected to demonstrate that recovery during the transition period is necessary, time sensitive, and cannot reasonably be pursued in a GRC or the utility's first MRP filing in order to balance potential burden from cumulative impact of the proposed increase on customers.

Staff's concept does not include cost overruns for recovery during the transition period; and no investment will be subject to recovery unless in use prior to the rate effective date. Based on learnings from recent ARMs, Staff's concept also contemplates that depreciation for the same class of asset is included and there is an earnings test where excess earnings would be refunded and there would be no automatic upward adjustment for earnings shortfalls.

Staff notes that utility bears the burden of demonstrating both necessity and time sensitivity. General statements of policy alignment, system benefit, or future need are not sufficient. Where the required showing is not made, the request will be denied without prejudice to later review.

Approval of cost recovery in an ARM does not limit the Commission's authority to review scope, cost management, or overruns in the first MRP.

Deferrals

Staff intends to utilize the transition period to focus on minimizing use of new deferrals for cost recovery outside of general rate cases. Staff recognizes that deferrals are used to facilitate various existing cost-recovery mechanisms and statutorily required programs and recovery of costs associated with extraordinary and unforeseen costs, but notes in several instances, deferrals are used to facilitate year-over-year and dollar-for-dollar, recovery of costs that could be forecasted and recovered through general rate cases.

Staff will closely scrutinize new deferral requests during the transition period and look for opportunities to streamline reauthorizations that are not associated with existing cost recovery mechanisms, statutorily required programs, or high cost extraordinary and unforeseen costs. Further, based on Staff's analysis of the utilities' success at obtaining authorization to amortize deferred costs, Staff concludes recovery risk may not be commensurate with the utilities authorized RoR. Instead, the likelihood that utilities will be allowed to amortize deferred costs, based on a review of past Commission decisions, may warrant a lower interest rate.

Staff's concept does not include the creation of new deferrals without approaches that balance utility and ratepayer impacts through application of the Modified Blended Treasury Rate or another industry-based rate to deferred amounts rather than the utility's rate of return where evidence exists that recovery of costs is more likely than the utilities standard business risk.

General Rate Cases

Staff's transition concept seeks to facilitate one or fewer GRCs filed consistent with HB 3179 and other existing statutes. In line with Staff's principles, the transition concept focuses on moderating cumulative rate impacts and limited the number of concurrently filed GRCs in the transition period. To this end, Staff recommends any utility GRC filing during the transition period demonstrate consideration of the following Staff objectives:

- Minimize transition period proceedings
    - Utilities limit GRC filings to one within two years of utility's first MRP.
    - Limited number of concurrent rate cases to two.
- GRC's demonstrate narrow focus and O&M discipline
    - Target total rate increase requests to track at or below inflation.
    - Prioritize the use of GRCs where O&M reductions are possible.
    - Focus on bringing new capital projects into rates that are focused on cost-effective reliability, safety, and long-term affordability.
    - Focus on urgent or non-discretionary costs, including investments with short depreciable lives.
    - Focus on projects that can be supported with a thorough non-wires, non-pipes, or other alternatives analysis informed by stakeholder input.
- Mindfulness of potential rate shock
    - Phased increase for rate increases above 5 percent.

Indexed O&M

Staff notes that discussion of indexing approaches such as a fixed percent annual rate increase during the transition period has been discussed at workshops. Staff's concept reserves consideration of indexing for the MRP framework development process and does not include any indexing mechanisms or inflation-based automatic adjustments during the transition period. Indexing can reduce regulatory burden but also weakens the link between costs and review. Introducing indexing prior to MRPs risks embedding cost assumptions that may not receive full scrutiny before becoming the baseline for MRPs.

Next Steps

- **Tuesday, March 10, 2026, 9:30-11:30 Pacific:** AR 677 Workshop
  - Presentation of Staff proposal for clarification and initial discussion.
- **Tuesday, March 17, 2026.** AR 677 Comment deadline (optional)
  - Comments on Staff proposal and workshop discussion.

- *HB 3179 implementation office hours, every Monday, 12:30-1:30 Pacific.*

Staff looks forward to stakeholder input on this proposal and appreciates all of the thoughtful engagement on these efforts to date.

If you have any questions regarding this document or process, please contact:

Michelle Scala | Regulatory Strategy Manager | 503-689-2608 | Michelle.m.scala@puc.oregon.gov

To receive meeting notices and agendas for this docket, send an email to puc.hearings@puc.oregon.gov, and ask to be added to the service list for Docket No. AR 677. You will then receive emails with workshop details, when new documents have been added to the docket, or there is a change to the schedule.

	Before UG 435	Before UG 435	Margin rate	percent of cost	After UG 527	After UG 527				Margin Increase since 10/2022 including UG 427	% increase	percent of margin allocated to class	
Rate Class	Load	Margin	$/therm	allocated to class	Load	Margin	$/therm		***Rate Class***	***cents/therm***			
2R	405,331,797	302,743,546	0.746903027	68.15%	416,418,766	444,097,259	1.066468		***Residential***	***31.96***	***43%***	***66.75%***	
3C	169,645,064	92,803,627	0.547045843	20.89%	196,563,124	161,785,011	0.823069		3C	27.60	50%	24.32%	
3I	5,085,467	2,141,772	0.421155422	0.48%	5,220,244	2,772,776	0.531158		3I	11.00	26%	0.42%	
31CSF	21,601,351	8,261,800	0.382466819	1.86%	23,738,500	11,191,258	0.471439		31CSF	8.90	23%	1.68%	
31CTF	2,595,724	981,292	0.378041733	0.22%	2,476,657	1,173,316	0.47375		31CTF	9.57	25%	0.18%	
31ISF	12,195,084	3,237,130	0.265445486	0.73%	10,630,853	3,572,900	0.336088		31ISF	7.06	27%	0.54%	
32CSF	45,329,318	11,882,484	0.262136836	2.67%	49,658,607	15,800,648	0.318185		32CSF	5.60	21%	2.37%	
32ISF	13,890,109	2,462,192	0.177262252	0.55%	22,726,355	4,349,501	0.191386		32ISF	1.41	8%	0.65%	
32CTF	6,506,107	1,024,698	0.157497871	0.23%	5,956,362	1,115,172	0.187224		32CTF	2.97	19%	0.17%	
32ITF	82,146,819	6,584,741	0.080158198	1.48%	90,250,815	7,482,855	0.082912		32ITF	0.28	3%	1.12%	
32CSI	25,010,820	2,232,839	0.089274922	0.50%	23,405,629	2,800,806	0.119664		32CSI	3.04	34%	0.42%	
32ISI	36,082,155	3,307,718	0.091671853	0.74%	28,706,209	2,919,181	0.101692		32ISI	1.00	11%	0.44%	
32CTI	6,860,150	525,889	0.076658528	0.12%	7,072,948	572,361	0.080923		32CTI	0.43	6%	0.09%	
33ITI	188,502,764	6,064,679	0.032172892		163,514,304	5,718,983	0.034975		33ITI	0.28	9%	0.86%	
total	1,020,782,729	444,254,407			1,046,339,373	665,352,027							
									Increase for residential customer using 650 therms/year				207.7172
sources:	UG 435/1401/1	UG 435/1402/1			UG 520/1601/1	UG 537/101/2							

NW Natural
Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2023
Long-Run Incremental Cost Study
Summary of Results
Exhibit NW Natural/1401, Wyman

Line No.			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
	CUSTOMER CLASS		Residential	Commercial	Industrial	Commercial	Commercial	Commercial	Industrial	Industrial	Commercial	Industrial	Commercial	Industrial	Commercial	Industrial	Transportation	Transportation	Transportation	
	SERVICE TYPE		Sales	Sales	Sales	Sales	Sales	Transportation	Sales	Transportation	Sales	Sales	Transportation	Transportation	Sales	Sales	Interruptible	Interruptible		
			Firm	Firm	Firm	Firm	Firm	Firm	Firm	Firm	Firm	Firm	Firm	Firm	Interruptible	Interruptible				Special
	RATE SCHEDULE –>	**Totals**	02R	03C	03I	27R	31CSF	31CTF	31ISF	31ITF	32CSF	32ISF	32CTF	32ITF	32CSI	32ISI	32CTI	32ITI	33T	Contracts
	STATISTICS																			
1	2023 TY ANNUAL THERM DELIVERIES *(excl. special contract)*	1,022,080,218	405,331,797	169,645,064	5,085,467	791,922	21,601,351	2,595,724	12,195,084	505,568	45,329,318	13,890,109	6,506,107	82,146,819	25,010,820	36,082,155	6,860,150	188,502,764	0	70,244,643
2	2023 TY AVG CUSTOMERS - END OF PERIOD	706,464	643,080	59,720	339	1,493	644	59	196	7	541	62	28	104	69	39	6	77	0	8
3	AVERAGE ANNUAL THERM DELIVERIES PER CUSTOMER	1,447	630	2,841	15,001	530	33,542	43,995	62,220	72,224	83,788	224,034	232,361	789,873	362,476	925,183	1,143,358	2,448,088	0	8,780,555
	AVERAGE WINTER SALES	119,267,637	54,327,488	21,716,965	537,525	116,202	2,718,061	324,384	1,180,673	52,947	5,275,667	1,244,702	746,146	7,683,601	2,628,683	3,305,787	669,007	16,739,799	0	
	AVERAGE SUMMER SALES	51,513,938	13,393,502	6,827,634	281,596	17,953	850,731	107,643	859,587	31,068	2,229,774	1,095,240	317,117	5,938,863	1,517,660	2,615,542	473,015	14,957,014	0	
4	ESTIMATED DESIGN DAY LOAD FACTOR	*29.3%*	*22.0%*	*23.4%*	*38.3%*	*21.1%*	*26.6%*	*44.8%*	*46.3%*	*42.8%*	*32.3%*	*57.5%*	*50.4%*	*60.7%*	*52.0%*	*54.7%*	*59.4%*	*58.8%*	*0.0%*	
	4a Average Daily Deliveries	2,800,220	1,110,498	464,781	13,933	2,170	59,182	7,112	33,411	1,385	124,190	38,055	17,825	225,060	68,523	98,855	18,795	516,446	0	
	4b Peak Day Deliveries	9,483,269	5,056,144	1,987,171	36,371	10,292	222,106	15,869	72,160	3,234	384,025	66,211	35,345	371,036	131,886	180,868	31,632	878,920	0	
	LRIC Cost Allocation Factors - Capital Cost Indirect Allocators																			
5	Distribution Main Design Day Peak & Average	100.00%	49.28%	19.67%	0.42%	0.10%	2.27%	0.19%	0.89%	0.04%	4.16%	0.89%	0.45%	5.13%	1.70%	2.39%	0.43%	11.98%	0.00%	0.00%
6	System Core Mains	100.00%	55.74%	22.16%	0.45%	0.11%	2.54%	0.21%	0.95%	0.04%	4.59%	0.94%	0.48%	5.39%	0.62%	0.90%	0.50%	4.36%	0.00%	0.00%
7	Capacity Incremental (System Reinforcement)	100.00%	61.20%	24.07%	0.44%	0.12%	2.69%	0.19%	0.87%	0.04%	4.65%	0.80%	0.43%	4.49%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
8	Transmission Mains	100.00%	55.41%	21.97%	0.44%	0.11%	2.50%	0.20%	0.91%	0.04%	4.47%	0.88%	0.45%	5.01%	0.77%	1.09%	0.31%	5.44%	0.00%	0.00%
9	Storage Winter Sales / Summer Sales Excess Ratio	100.00%	65.53%	23.84%	0.41%	0.16%	2.99%	0.00%	0.51%	0.00%	4.88%	0.24%	0.00%	0.00%	0.89%	0.55%	0.00%	0.00%	0.00%	0.00%
10	Service Lines	100.00%	81.86%	15.85%	0.35%	0.10%	0.58%	0.06%	0.18%	0.01%	0.56%	0.06%	0.03%	0.13%	0.08%	0.04%	0.01%	0.11%	0.00%	0.00%
11	Meters Average Installed Cost	100.00%	78.37%	17.07%	0.39%	0.18%	1.00%	0.10%	0.37%	0.01%	1.20%	0.20%	0.08%	0.31%	0.25%	0.12%	0.03%	0.34%	0.00%	0.00%
12	Account Service Cost per Customer	100.00%	91.18%	6.89%	0.04%	0.17%	0.60%	0.06%	0.18%	0.01%	0.51%	0.06%	0.03%	0.10%	0.06%	0.04%	0.01%	0.07%	0.00%	0.00%
13	Common Cost (Administrative, General Plant, etc.)	100.00%	76.98%	18.24%	0.36%	0.14%	0.85%	0.10%	0.36%	0.01%	1.11%	0.18%	0.08%	0.54%	0.25%	0.21%	0.04%	0.53%	0.00%	0.00%
	**For all allocation factors, including direct allocators and incremental expense allocators, refer to the "LRIC Allocators" tab.*																			
14	Total Rate Base by Functional Classification																			
	14a Meter Reading & Billing Costs	$20,215,113	$12,851,154	$5,417,059	$76,169	$21,399	$315,072	$27,992	$100,824	$3,538	$471,342	$65,963	$35,479	$312,546	$85,822	$78,600	$23,376	$328,779	$0	$0
	14b Meters & Services Costs	$570,704,150	$362,808,103	$152,932,023	$2,150,359	$604,116	$8,894,975	$790,250	$2,846,422	$99,897	$13,306,719	$1,862,238	$1,001,616	$8,823,656	$2,422,886	$2,218,996	$659,952	$9,281,941	$0	$0
	14c Core Main Costs	$681,258,172	$433,089,517	$182,557,268	$2,566,917	$721,143	$10,618,067	$943,333	$3,397,817	$119,249	$15,884,431	$2,222,982	$1,195,645	$10,532,931	$2,892,236	$2,648,849	$787,794	$11,079,993	$0	$0
	14d Transmission Costs	$186,266,768	$118,413,529	$49,914,047	$701,836	$197,172	$2,903,147	$257,922	$929,017	$32,605	$4,343,055	$607,798	$326,908	$2,879,870	$790,783	$724,237	$215,395	$3,029,446	$0	$0
	14e Gas Storage Costs	$270,853,849	$178,653,824	$75,306,727	$1,058,879	$297,479	$4,380,060	$0	$1,401,634	$0	$6,552,489	$917,002	$0	$0	$1,193,077	$1,092,677	$0	$0	$0	$0
15	**Total Rate Base**	**$1,729,298,051**	**$1,105,816,127**	**$466,127,123**	**$6,554,159**	**$1,841,309**	**$27,111,322**	**$2,019,496**	**$8,675,715**	**$255,289**	**$40,558,036**	**$5,675,983**	**$2,559,648**	**$22,549,003**	**$7,384,804**	**$6,763,359**	**$1,686,518**	**$23,720,159**	**$0**	**$0**
16	**Proposed Rate of Return**	6.886%																		
17	**Total Return on Rate Base at 9.5% ROE**	**$119,079,464**	**$76,146,499**	**$32,097,514**	**$451,319**	**$126,793**	**$1,866,886**	**$139,063**	**$597,410**	**$17,579**	**$2,792,826**	**$390,848**	**$176,257**	**$1,552,724**	**$508,518**	**$465,725**	**$116,134**	**$1,633,370**	**$0**	**$0**
18	**Revenue at Current Rates** *(incl misc rev)*	**$742,423,907**	**$468,913,370**	**$162,351,317**	**$4,226,612**	**$796,163**	**$17,117,489**	**$981,292**	**$8,236,625**	**$143,836**	**$30,465,691**	**$8,156,582**	**$1,024,698**	**$6,584,741**	**$10,222,297**	**$14,833,805**	**$525,889**	**$6,064,679**	**$0**	**$1,778,820**
	18a Cost of Gas Commodity	$295,775,335	$166,169,824	$69,547,690	$2,084,840	$324,655	$8,855,689	$0	$4,999,495	$0	$18,583,207	$5,694,390	$0	$0	$7,989,458	$11,526,087	$0	$0	$0	$0
	18b O&M and Other Operating Revenue Deductions	$379,471,944	$274,900,464	$75,846,013	$1,671,672	$468,998	$5,293,215	$652,326	$2,123,451	$79,949	$7,023,355	$1,277,203	$479,972	$3,027,613	$1,742,954	$1,794,479	$219,105	$2,871,175	$0	$0
	18c Net Operating Revenues	**$67,176,628**	**$27,843,082**	**$16,957,614**	**$470,099**	**$2,510**	**$2,968,586**	**$328,966**	**$1,113,679**	**$63,887**	**$4,859,129**	**$1,184,989**	**$544,726**	**$3,557,128**	**$489,886**	**$1,513,239**	**$306,784**	**$3,193,504**	**$0**	**$1,778,820**
19	**Incremental Net Operating Revenue Deficiency (Sufficiency)**																			
	19a *Net-to-Gross Revenue Sensitive Factor:*	140.916%																		
	19b **Component LRIC Target Increase by Schedule**	**$73,464,854**	**$67,206,093**	**$20,755,911**	**($42,625)**	**$175,388**	**($1,658,734)**	**($279,783)**	**($766,573)**	**($67,640)**	**($3,084,612)**	**($1,160,908)**	**($539,660)**	**($2,957,974)**	**$11,970**	**($1,527,598)**	**($280,184)**	**($2,318,218)**	**$0**	**$0**
	(incl. Corporate Activity Tax, credit for special contract revenues)																			
20	**Margin Revenue at Current Rates** *(incl misc rev)*	**$446,648,572**	**$302,743,546**	**$92,803,627**	**$2,141,772**	**$471,508**	**$8,261,800**	**$981,292**	**$3,237,130**	**$143,836**	**$11,882,484**	**$2,462,192**	**$1,024,698**	**$6,584,741**	**$2,232,839**	**$3,307,718**	**$525,889**	**$6,064,679**	**$0**	**$1,778,820**
21	**LRIC Based Target Margin**	**$520,113,425**	**$369,949,639**	**$113,559,538**	**$2,099,147**	**$646,895**	**$6,603,066**	**$701,510**	**$2,470,557**	**$76,195**	**$8,797,872**	**$1,301,284**	**$485,038**	**$3,626,767**	**$2,244,809**	**$1,780,120**	**$245,705**	**$3,746,461**	**$0**	**$1,778,820**
22	Current Revenue to Proposed Cost *(Includes Cost of Gas)*	**0.91**	**0.87**	**0.89**	**1.01**	**0.82**	**1.11**	**1.40**	**1.10**	**1.89**	**1.11**	**1.17**	**2.11**	**1.82**	**1.00**	**1.11**	**2.14**	**1.62**	**1.00**	**1.00**
23	Current Margin Revenue to LRIC Based Target Margin	**0.86**	**0.82**	**0.82**	**1.02**	**0.73**	**1.25**	**1.40**	**1.31**	**1.89**	**1.35**	**1.89**	**2.11**	**1.82**	**0.99**	**1.86**	**2.14**	**1.62**	**1.00**	**1.00**
	23a **Parity Ratio at Present Rates**	**1.00**	**0.95**	**0.95**	**1.19**	**0.85**	**1.46**	**1.63**	**1.53**	**2.20**	**1.57**	**2.20**	**2.46**	**2.11**	**1.16**	**2.16**	**2.49**	**1.89**	**1.00**	**1.00**
24	Target Increase as Percent of Total Present Revenue	**9.9%**	**14.3%**	**12.8%**	**-1.0%**	**22.0%**	**-9.7%**	**-28.5%**	**-9.3%**	**-47.0%**	**-10.1%**	**-14.2%**	**-52.7%**	**-44.9%**	**0.1%**	**-10.3%**	**-53.3%**	**-38.2%**	**0.0%**	**0.0%**
	24a Target Increase as Percent of Present Margin Revenue	**16.5%**	**22.2%**	**22.4%**	**-2.0%**	**37.2%**	**-20.1%**	**-28.5%**	**-23.7%**	**-47.0%**	**-26.0%**	**-47.1%**	**-52.7%**	**-44.9%**	**0.5%**	**-46.2%**	**-53.3%**	**-38.2%**	**0.0%**	**0.0%**
	(less special contract revenue)																			
25	Proposed Rate Revenue Increase	**$73,464,854**	**$52,494,153**	**$16,091,665**	**$154,530**	**$81,757**	**$1,065,964**	**$70,801**	**$233,561**	**$10,378**	**$1,533,116**	**$177,648**	**$73,933**	**$475,093**	**$288,088**	**$238,654**	**$37,943**	**$437,570**	**$0**	**$0**
	(see: NW Natural/1400, Wyman)																			
26	**Margin Revenue at Proposed Rates** *(incl misc rev)*	**$520,113,425**	**$355,237,699**	**$108,895,293**	**$2,296,302**	**$553,265**	**$9,327,765**	**$1,052,093**	**$3,470,691**	**$154,213**	**$13,415,600**	**$2,639,840**	**$1,098,631**	**$7,059,833**	**$2,520,927**	**$3,546,372**	**$563,832**	**$6,502,249**	**$0**	**$1,778,820**
	26a Revenue-to Cost Ratio at Proposed Rates	**1.00**	**0.96**	**0.96**	**1.09**	**0.86**	**1.41**	**1.50**	**1.40**	**2.02**	**1.52**	**2.03**	**2.27**	**1.95**	**1.12**	**1.99**	**2.29**	**1.74**	**1.00**	**1.00**
	26b Parity Ratio at Proposed Rates	**1.00**	**0.96**	**0.96**	**1.09**	**0.86**	**1.41**	**1.50**	**1.40**	**2.02**	**1.52**	**2.03**	**2.27**	**1.95**	**1.12**	**1.99**	**2.29**	**1.74**	**1.00**	**1.00**

NW Natural
Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2023
Rate Spread Allocation Proposal Methodology - Revenue Requirement Effects
Exhibit NW Natural/1402, Wyman

	Factor	Margin %
CAP at 1.05x:	**1.05**	17.3%
FLOOR at 0.5x:	**0.50**	8.3%

Adjusted FLOOR	
Factor	**0.44**
Margin %	7.2%

Line No.	Rate Schedule	Margin Revenue at Present Rates	Total Revenue at Present Rates	Target Increase (LRIC)	Parity Ratio at Present Rates (Unit Parity = 1.0)	Target Margin Increase (LRIC)	Equal % of Margin Increase	Step 1: Apply Cap: Parity Ratio Less than 1.0	Step 2: Apply Floor: Industrial & Transportation Classes	Step 3: Apply Remainder: Large Commercial Sales Class	Step 4: Apply LRIC-based Floor Adjustment to Industrial & Transportation Classes	Step 5: Apply LRIC-based Floor Adjustment to Large Commercial Sales Class	Total Proposed Revenue Requirement Increase	Proposed Margin Increase	Margin Revenue at Proposed Rates	Parity Ratio at Proposed Rates (Unit Parity = 1.0)
		$	$	%		$	$	G	H	I	J	K	$	%	$	%
		A	B	C	D	E	F						L	M	N	O
1	02	$ 302,743,546	$ 468,913,370	22.2%	0.95	$ 67,206,093	$ 49,994,431	$ 52,494,153					$ 52,494,153	17.3%	$ 355,237,699	0.96
2	03CSF	$ 92,803,627	$ 162,351,317	22.4%	0.95	$ 20,755,911	$ 15,325,396	$ 16,091,665					$ 16,091,665	17.3%	$ 108,895,293	0.96
3	03ISF	$ 2,141,772	$ 4,226,612	-2.0%	1.19	$ (42,625)	$ 353,688		$ 176,844		$ (21,670)		$ 155,173	7.2%	$ 2,296,945	1.09
4	27R	$ 471,508	$ 796,163	37.2%	0.85	$ 175,388	$ 77,864	$ 81,757					$ 81,757	17.3%	$ 553,265	0.86
5	31CSF	$ 8,261,800	$ 17,117,489	-20.1%	1.46	$ (1,658,734)	$ 1,364,336			$ 964,131		$ 98,897	$ 1,063,028	12.9%	$ 9,324,828	1.41
6	31CTF	$ 981,292	$ 981,292	-28.5%	1.63	$ (279,783)	$ 162,049		$ 81,024		$ (9,929)		$ 71,096	7.2%	$ 1,052,388	1.50
7	31ISF	$ 3,237,130	$ 8,236,625	-23.7%	1.53	$ (766,573)	$ 534,573		$ 267,286		$ (32,753)		$ 234,533	7.2%	$ 3,471,663	1.40
8	31ITF	$ 143,836	$ 143,836	-47.0%	2.20	$ (67,640)	$ 23,753		$ 11,876		$ (1,455)		$ 10,421	7.2%	$ 154,257	2.02
9	32CSF	$ 11,882,484	$ 30,465,691	-26.0%	1.57	$ (3,084,612)	$ 1,962,248			$ 1,386,655		$ 142,238	$ 1,528,893	12.9%	$ 13,411,377	1.52
10	32ISF	$ 2,462,192	$ 8,156,582	-47.1%	2.20	$ (1,160,908)	$ 406,601		$ 203,301		$ (24,912)		$ 178,388	7.2%	$ 2,640,580	2.03
11	32CTF	$ 1,024,698	$ 1,024,698	-52.7%	2.46	$ (539,660)	$ 169,216		$ 84,608		$ (10,368)		$ 74,240	7.2%	$ 1,098,938	2.27
12	32ITF	$ 6,584,741	$ 6,584,741	-44.9%	2.11	$ (2,957,974)	$ 1,087,390		$ 543,695		$ (66,624)		$ 477,071	7.2%	$ 7,061,811	1.95
13	32CSI	$ 2,232,839	$ 10,222,297	0.5%	1.16	$ 11,970	$ 368,726			$ 260,567		$ 26,728	$ 287,294	12.9%	$ 2,520,134	1.12
14	32ISI	$ 3,307,718	$ 14,833,805	-46.2%	2.16	$ (1,527,598)	$ 546,230		$ 273,115		$ (33,467)		$ 239,647	7.2%	$ 3,547,366	1.99
15	32CTI	$ 525,889	$ 525,889	-53.3%	2.49	$ (280,184)	$ 86,844		$ 43,422		$ (5,321)		$ 38,101	7.2%	$ 563,990	2.29
16	32ITI	$ 6,064,679	$ 6,064,679	-38.2%	1.89	$ (2,318,218)	$ 1,001,508		$ 500,754		$ (61,362)		$ 439,392	7.2%	$ 6,504,071	1.74
17	33T	$ 0	$ 0	0.0%	1.00	$ 0	$ 0		$ 0				$ 0	0.0%	$ 0	1.00
	Total	**$ 444,869,752** (1)	**$ 740,645,087** (1)	**16.5%**		**$ 73,464,854**	**Rev Req Applied:**	**$ 68,667,575**	**$ 2,185,926**	**$ 2,611,352**	**$ (267,863)**	**$ 267,863**	**$ 73,464,854**	**16.5%**	**$ 518,334,605** (1)	
Proposed Rev Req:		**$ 73,464,854**					**Rev Req Remainder:**	**$ 4,797,278**	**$ 2,611,352**	**$ 0**	**$ (267,863)**	**$ 0**				

Note **(1)**: Excludes special contract revenues.

NW Natural
Oregon Jurisdictional Rate Case - UG 520
Test Year Twelve Months Ended October 31, 2026
Rate Spread Allocation Proposal Methodology - Revenue Requirement Effects
Exhibit NW Natural/1602, Wyman

	Factor	Margin %
02R CAP:	**1.04**	9.8%
03C CAP:	**1.01**	9.5%
27R CAP:	**1.30**	12.3%
FLOOR at 0.64x:	**0.64**	6.0%

Line No.	Rate Schedule	Margin Revenue at Present Rates $	Total Revenue at Present Rates $	Target Increase (LRIC) %	Parity Ratio at Present Rates (Unit Parity = 1.0)	Target Margin Increase (LRIC) $	Equal % of Margin Increase $	Step 1: Apply Caps: Parity Ratio Less than 1.0 plus 03C	Step 2: Apply Floor: Transportation Class & Parity Ratio Over 1.29	Step 3: Apply Remainder: Remaining Schedules on Equal Percent of Margin Basis	Total Proposed Revenue Requirement Increase $	Proposed Margin Increase %	Margin Revenue at Proposed Rates $	Parity Ratio at Proposed Rates (Unit Parity = 1.0) %
		A	B	C	D	E	F	G	H	I	L	M	N	O
1	02R	$ 417,867,041	$ 634,454,777	13.3%	0.97	$ 55,564,596	$ 39,478,877	$ 41,058,032			$ 41,058,032	9.8%	$ 458,925,074	0.97
2	03CSF	$ 152,460,057	$ 254,696,468	7.8%	1.01	$ 11,924,131	$ 14,403,988	$ 14,548,028			$ 14,548,028	9.5%	$ 167,008,085	1.02
3	03ISF	$ 2,655,683	$ 5,370,888	-4.7%	1.15	$ (124,772)	$ 250,901			$ 186,520	$ 186,520	7.0%	$ 2,842,204	1.12
4	27R	$ 787,578	$ 1,268,018	42.7%	0.77	$ 336,330	$ 74,408	$ 96,731			$ 96,731	12.3%	$ 884,308	0.79
5	31CSF	$ 10,772,358	$ 23,119,224	-18.4%	1.34	$ (1,978,461)	$ 1,017,741		$ 651,355		$ 651,355	6.0%	$ 11,423,713	1.30
6	31CTF	$ 1,129,431	$ 1,129,431	-22.7%	1.42	$ (256,253)	$ 106,705		$ 68,291		$ 68,291	6.0%	$ 1,197,722	1.37
7	31ISF	$ 3,439,241	$ 8,968,560	-20.6%	1.38	$ (709,776)	$ 324,930		$ 207,955		$ 207,955	6.0%	$ 3,647,196	1.34
8	31ITF	$ 97,130	$ 97,130	-5.2%	1.15	$ (5,080)	$ 9,177			$ 6,822	$ 6,822	7.0%	$ 103,951	1.13
9	32CSF	$ 15,216,403	$ 41,044,837	-15.4%	1.29	$ (2,340,848)	$ 1,437,602		$ 920,065		$ 920,065	6.0%	$ 16,136,468	1.25
10	32ISF	$ 4,188,571	$ 16,009,003	-15.6%	1.30	$ (654,183)	$ 395,724		$ 253,263		$ 253,263	6.0%	$ 4,441,835	1.26
11	32CTF	$ 1,073,885	$ 1,073,885	-33.1%	1.64	$ (355,545)	$ 101,458		$ 64,933		$ 64,933	6.0%	$ 1,138,818	1.59
12	32ITF	$ 7,205,891	$ 7,205,891	-13.2%	1.26	$ (950,844)	$ 680,792			$ 506,102	$ 506,102	7.0%	$ 7,711,993	1.23
13	32CSI	$ 2,697,122	$ 12,816,545	-3.1%	1.13	$ (82,882)	$ 254,816			$ 189,431	$ 189,431	7.0%	$ 2,886,553	1.10
14	32ISI	$ 2,811,271	$ 15,222,405	0.2%	1.09	$ 6,203	$ 265,601			$ 197,448	$ 197,448	7.0%	$ 3,008,719	1.07
15	32CTI	$ 551,185	$ 551,185	-58.3%	2.62	$ (321,133)	$ 52,074		$ 33,328		$ 33,328	6.0%	$ 584,513	2.54
16	32ITI	$ 5,507,172	$ 5,507,172	-12.3%	1.25	$ (676,386)	$ 520,302			$ 386,793	$ 386,793	7.0%	$ 5,893,965	1.22
17	33T	$ 0	$ 0	0.0%	1.00	$ 0	$ 0				$ 0	0.0%	$ 0	1.00
	SPECIAL	$ 1,664,933	$ 1,664,933	0.0%	1.00						$ 0		$ 1,664,933	1.00
	Total	**$ 630,124,953 (1)**	**$ 1,030,200,353 (1)**	**9.4%**		**$ 59,375,097**	**Rev Req Applied:**	**$ 55,702,791**	**$ 2,199,190**	**$ 1,473,116**	**$ 59,375,097**	**9.4%**	**$ 689,500,049 (1)**	
Proposed Rev Req:		**$ 59,375,097**					**Rev Req Remainder:**	**$ 3,672,306**	**$ 1,473,116**	**$ 0**				

Note **(1)**: Includes special contract and miscellaneous revenues.

Avg Parity Ratio for schedules above 1.29: 1.57

Exhibit 105 Intentionally Omitted.

81st OREGON LEGISLATIVE ASSEMBLY--2021 Regular Session

Enrolled
House Bill 2475

Sponsored by Representatives POWER, PHAM; Representatives ALONSO LEON, CAMPOS, DEXTER, FAHEY, HOLVEY, KROPF, NOSSE, REYNOLDS, WILDE, WILLIAMS, Senators DEMBROW, GOLDEN, JAMA, LIEBER, PATTERSON, TAYLOR (Presession filed.)

CHAPTER .....

AN ACT

Relating to public utilities; creating new provisions; and amending ORS 756.010, 757.072 and 757.230.

Be It Enacted by the People of the State of Oregon:

SECTION 1. ORS 756.010 is amended to read:

756.010. As used in ORS chapters 756, 757, 758 and 759, except as otherwise specifically provided or unless the context requires otherwise:

(1) "Commission" means the Public Utility Commission of Oregon.

(2) "Commissioner" means a member of the Public Utility Commission of Oregon.

(3) "Customer" includes the patrons, passengers, shippers, subscribers, users of the service and consumers of the product of a public utility or telecommunications utility.

(4) "Environmental justice" means equal protection from environmental and health hazards and meaningful public participation in decisions that affect the environment in which people live, work, learn, practice spirituality and play.

(5) "Environmental justice communities" includes communities of color, communities experiencing lower incomes, tribal communities, rural communities, coastal communities, communities with limited infrastructure and other communities traditionally underrepresented in public processes and adversely harmed by environmental and health hazards, including but not limited to seniors, youth and persons with disabilities.

[*(4)*] **(6)** "Municipality" means any city, municipal corporation or quasi-municipal corporation.

[*(5)*] **(7)** "Person" includes individuals, joint ventures, partnerships, corporations and associations or their officers, employees, agents, lessees, assignees, trustees or receivers.

[*(6)*] **(8)** "Public utility" has the meaning given that term in ORS 757.005.

[*(7)*] **(9)** "Rate" means any fare, charge, joint rate, schedule or groups of rates or other remuneration or compensation for service.

[*(8)*] **(10)** "Service" is used in its broadest and most inclusive sense and includes equipment and facilities related to providing the service or the product served.

[*(9)*] **(11)** "Telecommunications utility" has the meaning given that term in ORS 759.005.

SECTION 2. ORS 757.230 is amended to read:

757.230. (1) The Public Utility Commission shall provide for a comprehensive classification of service for each public utility, and such classification may take into account the quantity used, the time when used, the purpose for which used, the existence of price competition or a service alternative, the services being provided, the conditions of service**, differential energy burdens on low-income customers and other economic, social equity or environmental justice factors**

that affect affordability for certain classes of utility customers, and any other reasonable consideration. Based on such considerations the commission may authorize classifications or schedules of rates applicable to individual customers or groups of customers. The service classifications and schedule forms shall be designed consistently with the requirements of ORS 469.010. Each public utility is required to conform its schedules of rates to such classification. If the commission determines that a tariff filing under ORS 757.205 results in a rate classification primarily related to price competition or a service alternative, the commission, at a minimum, shall consider the following:

(a) Whether the rate generates revenues at least sufficient to cover relevant short and long run costs of the utility during the term of the rates;

(b) Whether the rate generates revenues sufficient to insure that just and reasonable rates are established for remaining customers of the utility;

(c) For electric and natural gas utilities:

(A) Whether it is appropriate to incorporate interruption of service in the utility's rate agreement with the customer; and

(B) Whether the rate agreement requires the utility to acquire new resources to serve the load; and

(d) For electric utilities, for service to load not previously served, the effect of the rate on the utility's average system cost through the residential exchange provision of the Pacific Northwest Electric Power Planning and Conservation Act of 1980, Public Law 96-501, as amended.

(2) The commission may prescribe such changes in the form in which the schedules are issued by any public utility as may be found to be expedient. The commission shall adopt rules which allow any person who requests notice of tariff filings described under subsection (1) of this section to receive such notice.

SECTION 3. ORS 757.072 is amended to read:

757.072. (1) A public utility providing electricity or natural gas may enter into a written agreement with an organization that represents broad customer interests in regulatory proceedings conducted by the Public Utility Commission relating to public utilities that provide electricity or natural gas. The agreement shall govern the manner in which financial assistance may be provided to the organization. The agreement may provide for financial assistance to other organizations found by the commission to be qualified under subsection (2) of this section. More than one public utility or organization may join in a single agreement. Any agreement entered into under this section must be approved by the commission before any financial assistance is provided under the agreement.

(2)**(a)** Financial assistance under an agreement entered into under this section may be provided only to organizations that represent [*broad customer*] interests in regulatory proceedings before the commission relating to public utilities that provide electricity or natural gas **that are:**

(A) The broad interests of customers;

(B) The interests of low-income residential customers; or

(C) The interests of residential customers that are members of environmental justice communities.

(b) The commission by rule shall establish such qualifications as the commission deems appropriate for determining which organizations are eligible for financial assistance under an agreement entered into under this section.

(c) The total aggregate financial assistance available to all organizations that represent the interests described in paragraph (a)(B) and (C) of this subsection from all public utilities providing electricity or natural gas may not exceed $500,000 annually.

(d) The commission shall establish a process for evaluating and approving an agreement described in this section that includes the provision of financial assistance to organizations that represent the interests described in paragraph (a)(B) or (C) of this subsection. The commission must evaluate and approve an agreement described in this paragraph before financial assistance may be provided under the agreement. The agreement described in this paragraph shall govern the manner in which financial assistance may be provided to an organization found by the commission to be qualified under paragraph (a)(B) or (C) of this

subsection. More than one public utility or organization may join in a single agreement described in this paragraph.

(3) In administering an agreement entered into under this section, the commission by rule or order may determine:

(a) The amount of financial assistance that may be provided to any organization;

(b) The manner in which the financial assistance will be distributed;

(c) The manner in which the financial assistance will be recovered in the rates of the public utility under subsection (4) of this section; and

(d) Other matters necessary to administer the agreement.

(4) The commission shall allow a public utility that provides financial assistance under this section to recover the amounts so provided in rates. The commission shall allow a public utility to defer inclusion of those amounts in rates as provided in ORS 757.259 if the public utility so elects. An agreement under this section may not provide for payment of any amounts to the commission.

SECTION 4. The Public Utility Commission shall, no later than September 15, 2025, provide a report to the interim committees of the Legislative Assembly related to energy that discusses, for the period beginning on the effective date of this 2021 Act and ending December 31, 2024, the implementation and impacts of the amendments to ORS 757.072 by section 3 of this 2021 Act. The report shall include, but need not be limited to:

(1) A description of the process established under ORS 757.072 (2)(d) and any other rules, orders, processes or polices adopted or established by the commission as necessary to implement the amendments to ORS 757.072 by section 3 of this 2021 Act; and

(2) A detailed description of the organizations described in ORS 757.072 (2)(a)(B) and (C) that received funding during the period subject to reporting that includes, for each organization, a description of:

(a) The proceedings for which the organization received financial assistance;

(b) The amount of financial assistance received by the organization for each proceeding;

(c) The issues raised by the organization in each proceeding for which the organization received financial assistance; and

(d) The outcome within each proceeding with regard to the issues described in paragraph (c) of this subsection.

SECTION 5. Section 4 of this 2021 Act is repealed on January 2, 2026.

SECTION 6. Section 7 of this 2021 Act is added to and made a part of ORS chapter 757.

SECTION 7. (1) In addition to comprehensive classifications, tariff schedules, rates and bill credits, the Public Utility Commission may address the mitigation of energy burdens through bill reduction measures or programs that may include, but need not be limited to, demand response or weatherization.

(2) The costs of tariff schedules, rates, bill credits or program discounts allowed pursuant to subsection (1) of this section must be collected in the rates of an electric company through charges paid by all retail electricity consumers, such that retail electricity consumers that purchase electricity from electricity service suppliers pay the same amount to address the mitigation of energy burdens as retail electricity consumers that are not served by electricity service suppliers.

Passed by House March 16, 2021

.....
Timothy G. Sekerak, Chief Clerk of House

.....
Tina Kotek, Speaker of House

Passed by Senate May 13, 2021

.....
Peter Courtney, President of Senate

Received by Governor:

.....M.,....., 2021

Approved:

.....M.,....., 2021

.....
Kate Brown, Governor

Filed in Office of Secretary of State:

.....M.,....., 2021

.....
Shemia Fagan, Secretary of State

Portland General Electric
121 SW Salmon Street • Portland, OR 97204
portlandgeneral.com

July 25, 2025

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street, S.E.
P.O. Box 1088
Salem, OR 97308-1088

RE: Advice No. 25-22, UE 459 Schedule 121, Distribution System Plan Alternative Recovery Mechanism

Portland General Electric Company (PGE) submits this filing pursuant to Oregon Revised Statute (ORS) sections 757.205 and 757.210 and Oregon Administrative Rules (OARs) 860-022-0025 and 860-022-0030, for filing proposed tariff sheets associated with Tariff P.U.C. No. 19, with a requested effective date of **April 1, 2026**:

Fourth Revision of Sheet No. 1-2
Original Sheet No. 121-1
Original Sheet No. 121-2

Enclosed for filing is the following Testimony and Exhibits assigned as Docket No. UE 459:

- Jay Tinker, Jason Salmi Klotz (UE 459 PGE / 100-103)
- Joey Baranski, Kevin Putnam, Jack Podlesnik (UE 459 PGE / 200-201(C))
- Greg Batzler, Stephanie Meeks (UE 459 PGE / 300-302)
- Chris Pleasant (UE 459 PGE / 400-401)

PGE is submitting this filing to request recovery of the revenue requirement associated with new Schedule 121, Distribution System Plan Alternative Recovery Mechanism (DSP ARM). The DSP ARM includes specific capital projects in PGE's 2024 Distribution System Plan that are in-service by March 31, 2026. The mechanism only includes capital costs and related revenue calculations consistent with Docket UE 435 standards for all calculations. The overview and summary of the DSP ARM is provided in PGE's Testimony and supporting Exhibits.

To satisfy the requirements of OAR 860-022-0025(2) and OAR 860-022-0030(1), PGE responds as follows:

PGE estimates that approximately 953,000 Cost of Service (COS) customers will be impacted by this overall $72.2 million or 2.2% increase in COS revenues from the proposed Schedule 121 prices. A typical Schedule 7 customer consuming 784 kWh monthly will see a bill increase of $4.49 or 2.8%.

Work papers detailing the updated revenue requirements, price development and percentage impacts on customers is attached.

Please direct any questions regarding this filing to Greg Batzler at greg.batzler@pgn.com or Chris Pleasant at christopher.pleasant@pgn.com Please direct all formal correspondence and requests to pge.opuc.filings@pgn.com

Sincerely,

\s\ *Jay Tinker*

Jay Tinker
Senior Manager, Rates and Regulatory Affairs
Regulatory Operations

Enclosures

PGE Advice No. 25-22
Work Papers

Provided in electronic format and password protected

PORTLAND GENERAL ELECTRIC COMPANY
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RATE SCHEDULES (Continued)

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	Standard Service Schedules (Continued)	
81	Nonresidential Emergency Default Service	
83	Large Nonresidential Standard Service (31 – 200 kW)	
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86	Nonresidential Demand Buy Back Rider	
88	Load Reduction Program	
89	Large Nonresidential Standard Service (>4,000 kW)	
90	Large Nonresidential Standard Service (>4,000 kW and Aggregate to >30 MWa)	
91	Street and Highway Lighting Standard Service (Cost of Service)	
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100	Summary of Applicable Adjustments	
102	Federal Columbia River Benefits supplied by Bonneville Power Administration	
103	Metro Supportive Housing Services Business Income Tax Recovery	
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108	Public Purpose Charge	
109	Energy Efficiency Funding Adjustment	
115	Low Income Assistance	
118	Bill Adjustment Cost Recovery Mechanism	
120	Seaside Battery Storage Resource Alternative Recovery	
121	Distribution System Plan Alternative Recovery Mechanism	**(N)**
122	Renewable Resources Automatic Adjustment Clause	
123	Decoupling Adjustment	
125	Annual Power Cost Update	

SCHEDULE 121
DISTRIBUTION SYSTEM PLAN ALTERNATIVE RECOVERY MECHANISM

PURPOSE

This Schedule recovers the revenue requirement associated with PGE's Distribution System Plan.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service except Schedules 76R, and 576R.

ADJUSTMENT RATE

The Adjustment Rate, applicable for service on and after the effective date of this schedule are:

Schedule	Adjustment Rate	
7	0.564	¢ per kWh
15/515	0.597	¢ per kWh
32/532	0.524	¢ per kWh
38/538	0.691	¢ per kWh
47	0.910	¢ per kWh
49/549	0.876	¢ per kWh
75/575		
Secondary	0.062	¢ per kWh
Primary	0.062	¢ per kWh
Subtransmission	0.044	¢ per kWh
83/583	0.330	¢ per kWh
85/485/585		
Secondary	0.145	¢ per kWh
Primary	0.110	¢ per kWh

SCHEDULE 121 (Concluded)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate	
89/489/589/689		
Secondary	0.062	¢ per kWh
Primary	0.062	¢ per kWh
Subtransmission	0.044	¢ per kWh
90/490/590		
Primary 30-250 MWa	0.064	¢ per kWh
Primary >250 MWa	0.057	¢ per kWh
Subtransmission	0.064	¢ per kWh
91/491/591	0.600	¢ per kWh
92/492/592	0.167	¢ per kWh
95/495/595	0.600	¢ per kWh

SPECIAL CONDITIONS

1. Costs recovered through this schedule will be allocated to each schedule using the applicable schedule's forecasted energy on the basis of an equal percent of distribution revenue applied on a cents per kWh basis to each applicable rate schedule.

2. The costs for projects included under this schedule will be updated annually as provided above and will continue to be recovered under Schedule 121 until such time as the costs are included in base rates.

3. Once the Distribution System Plan is included in base rates or is no longer in service, this Schedule will be withdrawn, and no other assets will be placed within this Schedule.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 459

Application for Distribution System Plan Alternative Rate Mechanism

PORTLAND GENERAL ELECTRIC

Direct Testimony
Overview

Jay Tinker, PGE

Jason Salmi Klotz, PGE

July 25, 2025

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I. Introduction

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is Jay Tinker. I am employed by PGE as the Senior Manager of Rates and Regulatory Operations.

My name is Jason Salmi Klotz. I am employed by PGE as the Senior Manager Regulatory Strategy and Planning. Our qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to summarize PGE's request for Commission approval for rate recovery of specific distribution system investments through a Distribution System Plan Alternative Recovery Mechanism (DSP ARM). We will provide an overview of the DSP ARM and its relationship to the Distribution System Plan (DSP).[1] In recognition of the current challenging economic environment for our customers, PGE proposes a carefully and intentionally crafted approach to capital cost recovery that balances necessary investments to serve customers with consideration for customer affordability. This underscores PGE's dedication to addressing cost concerns while continuing the needed modernization of the grid. This approach was developed following constructive discussions between PGE and the Oregon Public Utility Commission Staff (Staff), the Citizens Utility Board (CUB) and the Alliance of Western Energy Consumers (AWEC). As a result, the DSP ARM was formulated as a pathway to narrow the scope of a rate review request to focus on the recovery of capital investments for distribution system planning and the Seaside Energy Battery Storage System (Seaside).[2]

[1] *PGE's 2024 Distribution System Plan*, Dkt. UM 2362, Initial Filing, (Dec. 18, 2024).
[2] *Request for Seaside Battery Storage Alternative Recovery Mechanism*, Dkt. UM 455.

Q. Describe the testimony and witnesses in this filing.

A. The testimony in this filing are as follows:

- Exhibit 200, DSP capital projects included in the DSP ARM will be addressed by witnesses Joey Baranski, Senior Director Project Management Office, Battery Energy Storage System Operations, and VPP Operations, Kevin Putnam, Senior Director Engineering Services, and Jack Podlesnik, Senior Director Grid Strategy, Transmission and Planning.
- Exhibit 300, DSM ARM revenue requirements by witnesses Greg Batzler, Manager of Revenue Requirement within Rates and Regulatory Affairs, and Stephanie Meeks, Regulatory Consultant, within Rates and Regulatory Affairs summarize the $72.3 million test year revenue requirement as of April 1, 2026.
- Exhibit 400, DSP ARM pricing and rate impacts by witness Christopher Pleasant, Regulatory Consultant, of Rates & Regulatory Affairs.

II. Overview and Summary

Q. Please provide an overview of PGE's request.

A. PGE is requesting recovery of a $72.3 million of revenue requirement for capital investments in the distribution system that either already are in service, or are expected to be in service, by the end of March 2026. The capital investments included in the revenue requirement calculation are limited to those specified in the DSP filed last December and are consistent with the provisions in the Memorandum of Understanding (MOU). The amounts requested, along with support for the adherence of calculations to the relevant MOU provisions, are discussed in more detail in PGE Exhibit 300. PGE is seeking to recover costs through a new DSP ARM tariff (Schedule 121) that will discontinue once all values become a part of base rates.

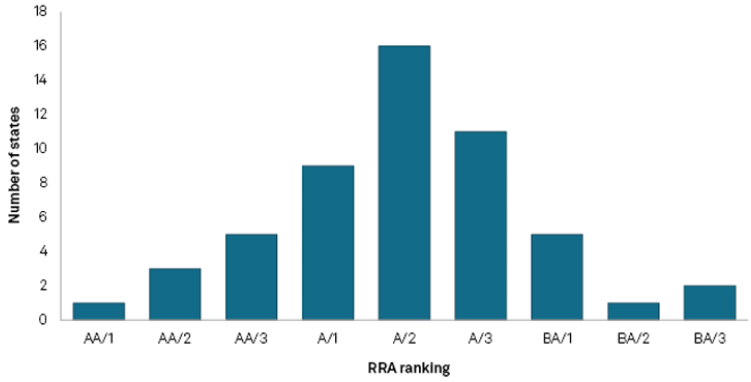
The DSP ARM offers a streamlined and focused regulatory tool that benefits both customers and the utility, particularly when compared to a general rate review. PGE makes this request to recover costs for targeted, in-service investments that directly enhance system reliability, safety, and affordability—investments that are foundational to meeting customer needs now and into the future. Unlike a general rate review, the DSP ARM limits the scope of recovery to discrete categories—[gross plant, depreciation, property taxes, and related items for DSP-specific capital investments]—using the current Commission-authorized cost of capital. This narrow and transparent approach balances cost recovery with sensitivity to customer affordability by avoiding the upward rate pressure of more expansive general rate reviews. Moreover, timely cost recovery through the DSP ARM signals to investors that Oregon's regulatory framework supports prudent infrastructure investment, thereby strengthening investor confidence. This confidence translates into continued access to low-

cost capital for PGE, ultimately lowering the long-term cost of critical infrastructure for customers.

Q. Is there a need to improve investor confidence in the regulatory environment for PGE?

A. Yes. While rating agencies, such as Moody's have always considered several aspects when evaluating utilities, the regulatory environment is a critical factor because it directly impacts utilities' financial stability and operational predictability. Rating agencies generally view favorably regulatory environments that provide utilities with timely cost recovery, reasonable returns, and mechanisms that reduce regulatory lag. State commissions that demonstrate consistent, predictable behavior tend to receive more positive assessments as they create a more stable operating environment for utilities like PGE. Regulatory Research Associates' (RRA) state regulatory evaluation is intended to assess the comparative level of risk for investors of owning the securities issued by utilities within each state regulatory jurisdiction. The RRA metric can range on a scale with the highest ranking being Above Average-1 through the lowest ranking of Below Average-3.

Figure 1
State regulatory rankings distribution: Energy



Data compiled June 20, 2025.
AA = Above Average; A = Average; BA = Below Average; RRA = Regulatory Research Associates.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.
© 2025 S&P Global.

On June 20, 2025, RRA adjusted their ranking of the regulatory climate for Oregon by downgrading it from an Average/2 to an Average/3.

PGE also received an A3 negative credit rating by Moody's on June 30, 2025, with Moody's noting for factors that could lead to an upgrade, "if PGE's regulatory framework strengthens to include credit-supportive mechanism (e.g., riders or trackers) that enable timely recovery of cash flows related to carbon transition investments."[3]

Q. How is the scope of PGE's request for recovery for this DSP ARM different from a general rate review request?

A. The scope for the DSP ARM is limited to DSP capital costs, for gross plant, accumulated reserve, accumulated deferred income taxes, depreciation expense, property taxes, and income tax expense for in scope capital investments that become operational and in-service during the timeframe of January 1, 2025 to March 31, 2026 but uses the current Commission-authorized cost of capital. In comparison, a general rate review is much broader in scope and includes several additional cost recovery request components, such as capital investments beyond the DSP, other regulatory assets and liabilities, return on equity, operation and maintenance expenses, the associated depreciation and amortization, taxes for the other investments, and other expenses or miscellaneous credits. The parameters of what can be addressed in the DSP ARM docket are outlined in the MOU which is discussed further in Section IV below.

[3] Moody's report filed as Exhibit 103C.

III. Distribution System Plan and Status

Q. What is the purpose of the Distribution System Plan?

A. The DSP serves as a comprehensive roadmap for building a modern, bi-directional, clean energy grid that is cost-effective and contributes to the goals of customer affordability, electrification and decarbonization. This strategic plan helps PGE make informed investment decisions to address grid modernization, virtual power plant (VPP) platform development, distributed energy resource (DER) integration, and traditional infrastructure needs. Taken together, these informed investment decisions are intended to meet evolving system and customer needs while creating transparency with stakeholders and fulfilling regulatory requirements established by the Commission.

Q. Why does PGE file a DSP with the Commission?

A. On March 13, 2019, Staff opened an investigation into Distribution System Planning. At the conclusion of that investigation in December 2020 the Commission issued Order No. 20-485 establishing the original approved DSP guidelines, which were most recently updated in Order No. 24-421. PGE filed part one of its first DSP on October 15, 2021,[4] which focused on baseline data and system assessments, estimated costs and timelines, a community engagement plan, and a long-term plan. Part two of PGE's DSP was filed on August 15, 2022, and focused on load growth forecasts, identification of areas where the distribution system will need improvements, options to address improvement opportunities, and project or investments selected for distribution system improvements. Both DSP submissions were accepted and approved by the Commission.[5] PGE provided its most recent DSP on

[4] *PGE's Distribution System Plan*, Dkt. UM 2197, Initial Filing (Oct. 15, 2021).
[5] UM 2197, Orders 22-083 and 23-069 for Parts1 and 2, respectively.

December 18, 2024, in accordance with the revised and updated guidance from the Commission.[6]

Q. Describe the DSP guidelines as applicable today and how PGE complied with those guidelines.

A. The DSP guidelines were updated most recently by the Commission in Order No. 24-421, which was issued on November 4, 2024. The guidelines are extensive and cover nine key areas:

- Process and Timing
- Commission Action
- Community Engagement
- Current System Data and Assessment
- Forecasting of Load Growth, DER Adoption, and EV Adoption
- Grid Needs
- Solution Identification
- Near-term Action Plan
- Long-term Plan

Throughout the development of the newly adopted DSP guidelines PGE worked closely with Staff to understand the scope, intentions, and expectations set by these new guidelines. As a result, we were able to file shortly after the Commission Order No. 24-421 adopting the new DSP guidelines.

[6] *Investigation Into Distribution System Planning*, Docket UM 2005, Order 24-421 (Nov. 15, 2024).

Q. Did PGE consider stakeholder input when developing the DSP?

A. Yes. For the 2024 DSP, PGE conducted community outreach through multiple channels to gather diverse stakeholder input. This included: 1) hosting five multi-hour distribution workshops throughout 2024; 2) providing informational material and discussing components of demand response, programs and concepts with representatives from environmental justice communities at Community Benefits and Impacts Advisory Group (CBIAG) meetings; 3) incorporating accessible educational materials for meaningful participation from traditionally underrepresented communities in the planning process; 4) Making copies of presentations and recordings available on PGE's website for transparency; and 5) holding two office hour sessions to allow for more candid discussions.

Q. Provide an overview and status on PGE's 2024 DSP.

A. Portland General Electric's 2024 Distribution System Plan (DSP)[7] documents a comprehensive strategy and compilation of information in compliance with Commission approved DSP guidelines,[8] which were developed from Staff working with the utilities and stakeholders for building a modern, clean energy grid that is cost-effective and contributes to the goals of customer affordability, electrification and decarbonizing. The plan also provides investment decision making process insights with reporting and planning information for DSP investments and operation of the grid.

The 2024 DSP revised schedule is displayed in Table 1 below which was revised on April 24, 2025. At the time of this filing, PGE has submitted its reply comments in docket UM 2362 and is awaiting the second round of comments from Staff and stakeholders.

[7] UM 2362
[8] UM 2005, Order 24-421 (Nov. 15, 2024).

Table 1
UM 2362: 2024 DSP Docket Schedule

Activity	Date
Public Comment Period on 2024 DSP	May 1 – June 13, 2025
Staff and Stakeholders 1st Round Comments published to the docket	June 13, 2025
PGE Reply to 1st Round Comments published	July 11, 2025
Staff and Stakeholders 2nd Round Comments published to the docket	August 22, 2025
PGE Reply to 2nd Round of Comments published	September 19, 2025
Staff's Memo published	October 21, 2025
Commission consideration of 2024 DSP at public meeting	October 28, 2025

IV. Memorandum of Understanding (MOU)

Q. Describe the Memorandum of Understanding (MOU).

A. The MOU, dated June 4, 2025, is an agreement between PGE, Staff, AWEC, and CUB (jointly, "the Signatories").[9] The MOU establishes an Alternative Recovery Mechanism (ARM) framework to limit the scope of cost recovery for the Seaside Battery Storage Project (Seaside) and the Distribution System Plan (DSP) investments. The Seaside and DSP ARMs are alternatives to PGE pursuing a full general rate review in 2025. While the Signatories disagree on the necessity of these ARMs, they've agreed to these limitations given current regulatory circumstances and recent legislation that has directed the Commission to consider multi-year rate plans and alternative ratemaking. In this filing we address the areas of the MOU pertaining to PGE's DSP that was filed in December 2024. The MOU establishes that all costs in either ARM will be subject to Commission prudence review.

Q. What is the importance of the MOU?

A. The MOU is an agreement between the Signatories limiting the scope of cost recovery to be requested in both the Seaside and the DSP ARMs while allowing customers to benefit from the investments made that are beyond the scope of these ARMs and for which PGE may not seek rate recovery until a future point in time. The MOU resulted from several months of discussions and thoughtful engagement between the Signatories. From PGE's perspective, we agreed to the MOU and limited scope of cost recovery in light of the affordability challenges facing customers and part of our commitment to keep customer prices as low as possible while still working to provide a safe and reliable system. By pursuing Seaside and DSP recovery through a limited one-time mechanism, PGE is able to significantly lessen the cost impacts to

[9] PGE Exhibit 101, MOU (June 4, 2025).

customers compared to a full general rate review. The MOU also recognizes the benefits customers gain from improvements and investments made to the system.

Q. Describe how customers benefit from the key conditions of the MOU.

A. Customers benefit in three key ways:

The first is that the MOU limits the scope of cost recovery to projects identified in the DSP filed in December 2024. As discussed in more detail in PGE's Exhibit 200, these are projects that went through a rigorous and very thorough internal stage-gating process where the planning for some of these projects began months if not years before the DSP was submitted to the Commission in December 2024. Further, PGE's 2024 DSP, inclusive of these projects, has seen robust engagement and stakeholder input. These capital investments and improvements directly benefit customers through essential infrastructure upgrades like pole replacements, safety enhancements, and improvements to system reliability, resiliency, and security.

Secondly, the rate effective date is timed for April 1, 2026, which avoids a rate change in the winter season. PGE is targeting a Commission order in this docket to allow for rates of a new tariff to go into effect on April 1, 2026,[10] which is after the 2025-2026 winter season. PGE avoids the impacts of rate increases for customers during the winter months.

Third, assuming PGE's requests for recovery for Seaside and the DSP capital projects are decided by the Commission on the merits, "PGE agrees to not file a request for a general rate review with a rate effective date before May 1, 2027."[11] By recovering the limited amounts identified in the MOU, customers will not only benefit from lower rate increases compared to

[10] *See* PGE Exhibit 101, MOU, Binding Agreements – 8.d. "A DSP ARM would have a rate effective date of April 1, 2026."
[11] *Id*., Binding Agreements –13.

a general rate review filed in 2025, but will also benefit from investments PGE is making in the system that are outside the scope of the DSP and for which the earliest a general rate review increase will occur is May 1, 2027. Throughout this period, customers will continue to benefit from PGE's ongoing capital improvements that are separate from the Seaside and DSP ARM programs. These additional investments are specifically designed to enhance customer service and infrastructure but are not part of the current cost recovery request.

The MOU can be found in Exhibit 101 and includes both a Non-Binding Understandings section and a section of Binding Agreements.

Q. Are there revenue requirement drivers PGE will not be seeking to recover through the DSP ARM?

A. Yes, as mentioned, increases in O&M expenses experienced by the company are not part of PGE's recovery request, nor are any amounts for additional capital improvements or investments in generation (and other non-2024 DSP specific) plant placed in-service throughout 2025 and 2026. While PGE continues to experience costs and uncertainty from supply chain disruptions and inflationary pressures in 2025, which are anticipated to increase in 2026, under the terms of the MOU, PGE will absorb regulatory lag on those capital and O&M costs until PGE's next general rate review which, pursuant to the MOU will have a rate effective date no earlier than May 1, 2027. Also, with an authorized ROE of 9.34%—one of the lowest authorized ROE for a regulated vertically integrated electric utility in the nation—and despite the fact that year over year, PGE's share price has dropped more than 13 percent, PGE will not be seeking to increase its authorized ROE in the DSP ARM.

Q. Why is recovery of DSP costs through the method detailed in the MOU reasonable from a regulatory perspective?

A. The MOU limits what PGE is seeking to recover to capital projects identified to a narrow set of capital investments that are placed in service for customer use by the rate effective date. In Order No. 24-454, while the Commission rejected PGE's request for a tracker to include Seaside in rates once it is placed in service it was open to consider alternative tools by stating that "we acknowledge that today's system investment needs may involve more frequent capital additions and thus, absent a change in our framework, frequent general rate review filings. We are open to alternatives to this outcome that fairly balance the interests of customers and investors."[12]

The Commission then invited PGE to make a new filing for a tracker to bring Seaside into rates that the Commission would consider approving on an expedited basis. In recognizing "that our decision makes frequent general rate review filings likely to continue" the Commission indicated an openness to considering an alternative means of cost recovery for PGE but pointed out that such an alternative rate mechanism "must balance the need for PGE to bring new investments into rates with the opportunity to capture for customers other costs that have decreased." The Commission also referenced recent changes to distribution system planning guidelines as uncovering ways to discipline overall pace and allocation of costs in capital investments in a way that "is carefully tuned to safety, reliability, and affordability."[13]

The DSP ARM as outlined in the MOU makes clear that PGE will forecast depreciation reserve and accumulated deferred tax offsets to DSP rate base through March 31, 2026, which

[12] UE 435, Order 24-454, 45 (Dec. 20, 2024).
[13] *Id*. 2.

provides the most up to date treatment before rates go into effect. Paragraph 8g of the MOU details the treatment.

From a regulatory perspective, the ARMs are consistent with the guidance provided by the Commission in Order No. 24-454. The ARMs also allow for administrative efficiency since although there are two separate ARM filings, they are still less burdensome for the Commission and parties when compared to a general rate review. Moreover, the ARMs allow for the protection of a full prudence review of the costs as well as the submission of attestations to ensure all capital projects identified in the DSP tracker are actually in-service before rates would go into effect on April 1, 2026.[14] Furthermore, with its use in 38 other states, capital cost trackers are "the most widely used [alternative] tool in American retail ratemaking. For electric companies, trackers for generation capacity, smart grid investments, and replacement of aging assets have been especially common in recent years."[15]

Q. Is the MOU binding on the Signatories?

A. While PGE and the other Signatories are not seeking a Commission order approving the MOU because it is not considered the same as a settlement agreement filed for Commission approval after the start of a contested case, the Signatories did have several discussions about what to include or not include in the MOU and as Paragraph 17 states, "[t]he Signatories reached the terms of this MOU as an integrated document with all non-binding understanding and binding agreements considered critical elements in reaching consensus for supporting this MOU. Should a Signatory not act consistently with the MOU, the terms of the MOU shall not be considered binding on any other Signatory."

[14] *See* PGE Exhibit 101, MOU, Binding Agreements – Paragraph 8i.
[15] Mark Newton Lowry, Matt Makos, Gretchen Waschbusch, and Benjamin Cohen, "Innovative Regulatory Tools for Addressing an Increasingly Complex Energy Landscape: 2023 Update," Edison Electric Institute, (Feb. 2024).

Q. Would approval for recovery of capital investments through the ARMs as outlined in the MOU establish precedent for utilities seeking similar single-issue ratemaking in the future?

A. No. In fact, the MOU specifically addresses this concern in Paragraph 3 of the Non-Binding Understandings where it makes clear that the Signatories did not intend for the MOU to be construed as establishing precedent in future proceedings beyond those specifically contemplated in the Seaside and DSP ARMS proceedings. PGE does not see the use of the DSP ARM or the agreement reached in the MOU as a presage of future requests but rather a tool in the Commission's existing tool kit that can be used until alternatives—such as multi-year rate plans—can reasonably be implemented. That is why PGE proposes the use of new separate tariff schedules for recovery of the Seaside and DSP ARMs that will terminate once all values become a part of base rates. As Paragraph 9 of the Binding Agreements section of the MOU states, "[t]he schedules are not intended for repeat use and will be withdrawn once no longer in use."

Q. Does this filing provide the information related to the DSP ARM as outlined in the Binding Agreements section from the MOU?

A. Yes. PGE Exhibit 102 provides an index for the MOU binding agreements, which identified information to be provided in this filing. Exhibit 102 provides the description of the information in the binding agreements to be addressed and both the location in the MOU and where the information is provided in this filing.

V. Benefits of DSP Acknowledgement and DSP ARM Approval

Q. What are the benefits of the acknowledgement of the DSP?

A. There is a benefit of having an acknowledged DSP from the Commission in providing the understanding to all stakeholders on the direction that PGE's DSP is heading. It assists in rate review filings, such as this filing, by providing the planning context for the investments PGE is seeking recovery. PGE filed the DSP on December 18, 2024, in Docket UM 2362. The DSP describes PGE's strategy of planned capital investments over the next two to four years for grid modernization and infrastructure upgrades. A summary of annual projected distribution system investments for 2024 through 2028 were identified in Chapter 8, Table 25 and Table 26 of the DSP.

Q. Why should PGE be allowed recovery of all projects in the DSP as outlined in the MOU through an ARM?

A. As PGE looks towards the future of energy in the West, PGE's DSP represents critical infrastructure investments that deserve appropriate cost recovery. The DSP is not simply a utility program, but rather a roadmap for creating a more reliable, resilient and equitable grid that serves our communities. These investments support our transition to clean energy while maintaining the reliable service our customers expect.

These investments directly benefit customers through modernized infrastructure, the replacement of aging equipment, meeting regulatory requirements, and help the grid to support increased electrification and renewable integration. These investments represent prudent planning for the future. By upgrading the distribution system now, PGE is working to mitigate the need for more costly emergency replacements later while meeting growing

demand on the system. The cost of these investments and improvements should be recovered because they represent necessary investments that benefit all customers.

Furthermore, recovery of these prudent investments allows PGE to continue being a financially stable utility, which assists in maintaining lower financing costs for on-going investments. Being a financially stable utility will help PGE gain access to capital markets at more favorable rates. Lower financing costs means PGE can fund future essential infrastructure projects at a lower overall cost. This translates directly to savings benefits for customers because for every percentage point reduction in our borrowing costs, millions of dollars can be saved on large-scale projects. Financial stability also means PGE can weather unexpected challenges without compromising service. Whether facing natural disasters, economic downturns, or unforeseen system demands, a strong financial footing allows PGE to respond effectively. Beyond immediate cost benefits, a financially healthy PGE enables strategic long-term planning for future investments rather than needing to focus solely on short-term patches. This approach creates a more resilient grid and helps smooth rates for customers over time. Customers also benefit from a smoothing of rate increases over time with the Commission's approval of the DSP ARM since rate increases for capital improvements are not only limited but also staggered with Seaside rates targeted to go into effect in October 2025 and the DSP ARM in April 2026.

The Commission should approve recovery of the projects in PGE's DSP through a DSP ARM because it strikes a meaningful balance: it addresses the need for modern, grid investments while supporting customer affordability through regulatory efficiency and financial discipline.

VI. Qualifications

Q. Jay Tinker, please state your educational background and experience.

A. I received a Bachelor of Science in Finance and Economics from Portland State University and a Master of Science in Economics from Portland State University. I began working for the Company in June 1996 in Rates and Regulatory Affairs and entered my current position as Senior Manager of Regulatory Operations in March 2025.

Q. Jason Salmi Klotz, please state your educational background and experience.

A. I hold a Masters in Environmental Law and a Juris Doctor from Vermont Law School and am member of the Oregon State Bar. Prior to working for Portland General Electric, I have worked for FERC, the Vermont Public Service Board, the California Public Utilities Commission and the Oregon Public Utilities Commission. At PGE I have held several positions: Senior Manager in PGE's Customer Programs department, Senior Manager in PGE's Planning department overseeing the development of the 2024 Distribution System Plan, as well as PGE's Transportation Electrification Plan and our Flex Load Multi-Year Plan. I currently hold the position of Senior Manager of Regulatory Affairs Strategy and Planning.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
101	June 4, 2025, Memorandum of Understanding
102	Memorandum of Understanding Index
103C	Moody's Credit Opinion Dated June 30, 2025

Memorandum of Understanding

This **MEMORANDUM OF UNDERSTANDING** (**"MOU"**) is made as of June 4, 2025 (the "Effective Date") by and among Portland General Electric Company ("PGE"); the Staff of the Public Utility Commission of Oregon ("Staff"); the Alliance of Western Energy Consumers ("AWEC"); and the Oregon Citizens' Utility Board ("CUB") (individually referred to as a "Signatory" and collectively referred to as the "Signatories").

Background:

Based on the Public Utility Commission of Oregon's ("Commission's") order in UE 435, the current regulatory framework in Oregon, the lack of regulatory limits on when and how often PGE can file a rate case, and given current unique circumstances in which the legislature is considering implementing multi-year rate plans or other alternative ratemaking mechanisms, the Signatories, established an MOU that lays out the scope of an Alternative Recovery Mechanism ("ARM") to limit the scope of costs that may be recovered through the Seaside and Distribution System Plan ("DSP") ARM in comparison to costs sought in a general rate review.

While the Signatories do not agree on the need or appropriateness of a Seaside or DSP ARM, the Signatories are entering into this MOU to limit the scope of these rate proceedings as an alternative to PGE deciding to pursue a general rate review in 2025.

This MOU sets forth certain non-binding understandings and binding agreements among the Signatories. Except as expressly set forth in the section of this MOU titled "Binding Agreements" nothing in this MOU constitutes a binding agreement of the Signatories. Furthermore, the existence of this MOU shall not be construed as establishing precedent or the ability of the Signatories to rely on this MOU for any future regulatory action beyond those contemplated in this MOU.

Non-Binding Understandings

The following paragraphs in this Non-Binding Understandings section do not constitute legally binding agreements of any Signatory.

1. Seaside has a contractual online date of August 21, 2025. In Docket UE 435, PGE identified a fully-loaded capital cost of $396 million for Seaside in PGE Exhibit 1700 at page 15 and a total rate base amount of 268.1 million, net of ITC benefits, in PGE Exhibit 2401.
2. PGE filed its DSP on December 18, 2024, in Docket UM-2362. The DSP describes PGE's strategy of planned capital investments over the next two to four years for grid modernization and infrastructure upgrades. A summary of annual projected distribution system investments for 2024 through 2028 were identified in Chapter 8, Table 25 and Table 26 of the DSP, with Appendix E of the DSP providing detailed project summaries for planned investments estimated to cost more than $2 million.
3. A Signatory's agreement to this MOU shall not be construed as a policy position of that Signatory on ARMs, single issue ratemaking, or general rate cases in any future proceeding beyond the ARM proceedings specifically contemplated in this MOU.

Binding Agreements

The following paragraphs in this Binding Agreements section are the only binding agreements of the Signatories in this MOU.

1. For purposes of this MOU, "Capital Costs" means gross plant, accumulated reserve, accumulated deferred income taxes, depreciation expense, investment tax credits, property taxes, and current deferred taxes.
2. For purposes of this MOU a "general rate review" is considered a filing by PGE pursuant to OAR 860-022-0019 that affects all or most of PGE's rate schedules and includes a determination by the Commission of the authorized return on equity. For the avoidance of doubt, "general rate review" shall not include any advice or rate filing for service for new large loads or data centers.
3. For purposes of this MOU, "Alternative Rate Mechanism" or "ARM" means tariff filings to recover the costs of the Seaside Battery Storage Project and specified distribution system investments as further described in this MOU.
4. All costs included in either ARM will be subject to review by the Commission for prudence based on the record developed by PGE, Staff, and intervenors in the docket.
5. For purposes of this MOU, "Loadings and Overheads" means allocable administrative and overhead costs, a portion of which are assigned to capital projects.
6. For purposes of this MOU, "Revenue Sensitive Rates" are Cost of Debt, Return on Equity, Cap Structure, State Tax Rate, Federal Tax Rate, Uncollectibles Rate, Franchise Fee Rate, Working Cash Factor, and OPUC Fee Rate.

Seaside

7. The Signatories agree that for a Seaside ARM the following conditions shall apply:
   a. The Capital Costs PGE will seek to recover in a Seaside Tracker shall not exceed the Capital Costs provided for Seaside in UE 435 PGE Exhibit 2401, as modified to use the Commission-approved ROE of 9.34%.
   b. A Seaside ARM will have a target final order date by October 26, 2025.
   c. All revenue sensitive rates and calculations must be consistent with the final outcome of UE 435.
   d. Rate base will be calculated as of October 31, 2025, and include depreciation expense, accumulated depreciation and deferred taxes consistent with the method used for setting prices in UE 435.
   e. PGE must forecast depreciation reserve and accumulated deferred tax offsets to Seaside rate base through October 31, 2025. Reserve offsets will be aligned with UE 435 final approved depreciation expense for battery assets.
   f. PGE's initial filing in the Seaside ARM will include a demonstration that PGE is absorbing regulatory lag on investments outside of the ARMs expected to be placed in service relative to changes in depreciation and deferred tax offsets over the same period.
   g. In addition to e) above, PGE will provide a rate base credit for forecast battery storage (i.e., Constable, Coffee Creek, and all other battery storage forecast to FERC 363 in UE 435), depreciation relative to UE 435 results through October 31, 2025.

DSP ARM

8. The Signatories agree that for a DSP ARM the following conditions shall apply:
   a. The scope of the revenue requirement under the DSP ARM is the revenue requirement of the capital projects identified in Appendix E for projects over $2 million plus the revenue requirement of the capital projects under $2 million as stated in the DSP in Appendix I for projects that will be in service as of the rate effective date. Additionally, PGE will provide information demonstrating that all projects included in the DSP ARM are also included within Tables 25 and 26 of the DSP. Signatories are not prohibited from bringing the costs and benefits associated with the distribution investment as described in the DSP into the scope of the DSP ARM. Signatories are not prohibited from raising issues related to the practice of recovery of distribution system costs through customer rates. The reference DSP was filed with the Commission in Docket UM 2362 in December 2024.
   b. Only capital amounts, Capital Costs, and revenue sensitive calculations can be included in the revenue requirement request included in a DSP ARM.
   c. All Revenue Sensitive Rates and calculations (i.e., method of applying the rates within PGE's revenue requirement) must be consistent with the final outcome of UE 435.
   d. A DSP ARM would have a rate effective date of April 1, 2026.
   e. Capital projects can be included in revenue requirement only if in-service on or before March 31, 2026, and will reflect application of Loadings and Overheads and Allowance for Funds Used During Construction (AFUDC) consistent with standard accounting practices and procedures.
   f. PGE's Loadings and Overheads and AFUDC policies must be supported in PGE testimony and subject to Party evaluation for reasonableness as part of a DSP ARM. PGE will file workpapers in a DSP ARM that provide detailed information regarding forecast loadings and AFUDC used to develop rate base amounts. PGE will demonstrate that loading rates are consistent with the loading rates as applied in UE 435.
   g. PGE must forecast depreciation reserve and accumulated deferred tax offsets to DSP rate base through March 31, 2026. Reserve offsets will be aligned with UE 435 final approved unbundled depreciation expense for distribution and transmission functionalized assets.
   h. Notwithstanding 8.g., depreciation expense, accumulated depreciations, and deferred taxes will be calculated consistent with the method used for setting prices in UE 435.
   i. PGE must submit an attestation for all capital projects identified in a DSP Tracker that are in-service by March 31, 2026. Should the net total exceed the proposed capital recovery within the filing, the total allowed in customer prices can be no greater than the filed amount.

Both

9. PGE must bill Seaside and DSP ARMs to customers through new separate tariff schedules, which will terminate once all values become a part of base rates in the next rate review proceeding. The schedules are not intended for repeat use and will be withdrawn once no longer in use. Should the separate schedules be in effect at the one-

year anniversary of their respective effective dates, PGE will update the Capital Costs for each schedule.

10. Seaside and DSP ARMs are limited in scope to address the recovery in customer rates of the specific items described in Paragraphs 7 and 8 of the Binding Agreements section of this MOU. The Signatories agree to act in good faith and use best efforts to either remain neutral or defend the scope of the proceeding as outlined in this MOU. In the event non-MOU parties raise additional issues beyond the scope of this MOU, this MOU does not preclude the Signatories from also presenting evidence into the record responsive to other issues or cost recovery items that may be raised by parties to the Seaside and DSP ARMs who are not parties to this MOU. If the Signatories disagree whether an issue or cost recovery item raised by a party is within the scope of the MOU they will convene to determine next steps.
11. Notwithstanding Section 10, above, Staff, CUB, and AWEC are not prohibited from proposing an earnings test and PGE is not prohibited from opposing such a proposal.
12. For purposes of Seaside and DSP ARMs, rate base must be calculated in the same manner as the Commission authorized PGE to use for capital projects in Docket UE 435.
13. If the Commission decides both of PGE's filings to establish Seaside and DSP ARMs on the merits, PGE agrees to not file a request for a general rate review with a rate effective date before May 1, 2027 (inclusive of the statutory nine-month suspension period). Accordingly, PGE could submit a request for a general rate review as early as July 1, 2026.
14. PGE will offer the MOU as an Exhibit to its opening testimony for both ARMs along with PGE-specific rationale for support of the MOU. Other Signatories will offer their rationale for supporting the MOU in subsequent filings related to each ARM at their discretion.
15. The Signatories will submit to the Commission the following Joint Proposed Procedural Schedules or not oppose PGE submitting the following proposed procedural schedules with the Commission:
    a. Proposed Schedule for a Seaside ARM is as follows:
        1) PGE files direct testimony and a proposed tariff change May 30, 2025.
        2) Parties file responsive testimony July 25, 2025.
        3) PGE files reply testimony August 18, 2025.
        4) Hearing tentative August 28.
        5) Simultaneous opening briefs September 16, 2025.
        6) Simultaneous closing briefs early October (2 weeks from opening brief).
        7) Target Commission Order October 26, prices effective by October 31, 2025.
    b. Proposed Schedule for a DSP ARM is as follows:
        1) PGE files direct testimony and a proposed tariff change July 25, 2025.
        2) Parties file responsive testimony October 24, 2025.
        3) PGE files reply testimony November 21, 2025.
        4) All-Party Pre-Hearing Brief mid-December.
        5) Hearing tentative early January.
        5) All-Party Post-Hearing briefs mid-February 2026.
        6) PGE reply brief late February 2026.
        7) Commission Order March 20, 2026, compliance filing by March 27, prices effective April 1, 2026.
16. This MOU does not limit or in any manner impair PGE's ability to seek recovery in its next rate case for any amounts related to Seaside, projects in the DSP, or other

amounts associated with capital projects incurred in 2026 following the stay out provision that are not otherwise recovered in customer rates.

17. The Signatories reached the terms of this MOU as an integrated document with all non-binding understandings and binding agreements considered critical elements to reaching consensus for supporting this MOU. Should a Signatory not act consistently with the MOU, the terms of the MOU shall not be considered binding on any other Signatory.
18. Except as provided in this MOU, no Signatory shall be deemed to have agreed that any provision of this MOU is appropriate for resolving issues in any proceeding other than the Seaside ARM or the DSP ARM.
19. By entering into this MOU, no Signatory shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by another Signatory beyond what is agreed to in this MOU. Nothing in this MOU shall be construed as creating a partnership or association between or among the Signatories. No Signatory shall have any power or authority to enter into commitment on behalf of or otherwise bind any other Signatory on other matters.
20. This MOU may be signed in any number of counterparts, each of which will be an original for all purposes, but all of which taken together will constitute one and the same agreement. This Binding Agreements section is the entire agreement of the Signatories related to the subject matter herein. This MOU may be amended only by a written agreement signed by all Signatories.
21. Signatories agree that the Commission shall have exclusive jurisdiction to resolve any dispute between the Signatories concerning this MOU.

KSB
KSB

Angelica Espinosa (Jun 11, 2025 13:26 PDT)

PORTLAND GENERAL ELECTRIC COMPANY

Stephanie S. Andrus
Stephanie S. Andrus (Jun 9, 2025 13:00 PDT)

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

/s/Claire Valentino-Fossum

OREGON CITIZENS' UTILITY BOARD

Tyler Pepple
Tyler Pepple (Jun 10, 2025 10:10 PDT)

ALLIANCE OF WESTERN ENERGY CONSUMERS

UE 459 / PGE / 102
Tinker - Klotz / 1

Memorandum of Understanding Index

Description	MOU	DSP ARM
"the scope of revenue requirement of projects to DSP Appendix E and Appendix I, and demonstrate all projects included in DSP Table 25 and 26"	Binding Agreements 8.a.	Workpaper DSP Projects Table 25 and 26 to DSP ARM
"Only capital amounts: capital costs, and revenue sensitive calculations included in the revenue requirement request. "All revenue sensitive rates and calculations must be consistent with the final outcome of UE 435"	Binding Agreements 8.b. and c.	DSP Revreq Work Paper
"Capital projects in revenue requirement one if in-service on or before March 31, 2026, and will reflect application of loadings, overheads, and AFUDC consistent with standard accounting practices and procedures."	Binding Agreements 8.e.	Exhibit 302 and 303
"PGE's Loadings and Overheads and AFUDC policies must be supported in PGE testimony and subject to Party evaluation for reasonableness as part of a DSP ARM. PGE will file workpapers in a DSP ARM that provide detailed information regarding forecast loadings and AFUDC used to develop rate base amounts. PGE will demonstrate that loading rates are consistent with the loading rates as applied in UE 435."	Binding Agreements 8.f.	Exhibit 300
"PGE must forecast depreciation reserve and accumulated deferred tax offsets to DSP rate base through March 31, 2026. Reserve offsets will be aligned with UE 435 final approved unbundled depreciation expense for distribution and transmission functionalized assets."	Binding Agreements 8.g.	DSP Revreq Work Paper
"Notwithstanding 8.g., depreciation expense, accumulated depreciations, and deferred taxes will be calculated consistent with the method used for setting prices in UE 435."	Binding Agreements 8.h.	DSP Revreq Work Paper
"PGE must submit an attestation for all capital projects identified in a DSP Tracker that are in-service by March 31, 2026."	Binding Agreements 8.i.	Provide within procedural schedule.
"DSP ARMs to customers through new separate tariff schedules, which will terminate once all values become a part of base rates in the next rate review proceeding."	Binding Agreements 9.	Exhibit 400
"DSP ARMs, rate base must be calculated in the same manner as the Commission authorized PGE to use for capital projects in Docket UE 435."	Binding Agreements 12.	Exhibit 301
"PGE will offer the MOU as an Exhibit to its opening testimony for both ARMs along with PGE-specific rationale for support of the MOU."	Binding Agreements 14.	Exhibit 100

UE 459

Exhibit 103C contains confidential information

Exhibit 103C is protected by General Protective Order No. 23-132

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 459

Application for Distribution System Plan Alternative Rate Mechanism

PORTLAND GENERAL ELECTRIC

Direct Testimony
DSP Capital

Joey Baranski, PGE

Kevin Putnam, PGE

Jack Podlesnik, PGE

July 25, 2025

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I. Introduction and Summary

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is Joey Baranski. I am employed by PGE as the Senior Director of the Project Management Office, Battery Energy Storage System Operations, and VPP Operations.

My name is Kevin Putnam. I am employed by PGE as the Senior Director of Engineering and Design.

My name is Jack Podlesnik. I am employed by PGE as the Senior Director of Grid Strategy, Transmission and Planning. Our qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to discuss the Distribution System Plan (DSP) projects that are included in this filing for cost recovery. We discuss PGE's capital planning process for identifying system needs and selecting the projects and the benefits of the projects for both the system and customers. Ultimately, the timely recovery of costs associated with these projects, which directly benefit customers is critical for PGE to continue to maintain a reliable, safe and affordable system at the lowest cost to customers well into the future.

Q. Please provide an overview of the testimony.

A. This testimony discusses the DSP projects, which are in this request for recovery review. We discuss the project categories and the importance of each category of investments to maintain and improve the grid. Our testimony provides details on the capital investment projects including documenting the requirements from Section 8 of Order No. 24-421 in Docket UM 2005 (i.e., revisions to distribution system planning guidelines) for the projects being reviewed for recovery in Exhibit 201.

II. Distribution System Plan (DSP) ARM Projects

Q. What are the types of projects in the DSP, and those requested in this DSP ARM?

A. DSP[1] projects are broadly categorized into six categories, shown in Table 1 below, all of which advance PGE's distribution system strategy to maintain a safe and reliable system and enabled grid for customers. In this DSP ARM filing, we request recovery for 72 projects, representing $655 million of capital in-service by March 31, 2026.

Table 1
DSP ARM Projects
($ in Millions)

Project Category	Number of Projects	Capital In-Service ($)
Capacity/Flexibility	3	$51
Compliance	10	$155
Customer/Partner	22	$264
Grid Modernization	18	$74
Operations	2	$2
Reliability	17	$103
Reserve*		$6
Total	**72**	**$655**

*Reserve for DSP projects anticipated to close by March 31, 2026.

Q. Please describe the project categories and the function they serve.

A. Included projects are classified into the following categories, based on primary justification for the project group:

A. Capacity/Flexibility – increase capacity and/or flexibility to address load growth or increase demand; may include capacity-driven compliance and reliability projects.

B. Compliance – address a non-capacity related compliance requirement from FERC, NERC, OPUC, EPA, DEQ,[2] or other regulatory body.

[1] *PGE's 2024 Distribution System Plan*, Dkt. UM 2362, Initial Filing at 304 (Dec. 18, 2024).
[2] Federal Energy Regulatory Commission, North American Reliability Corporation, Oregon Public Utility Commission, Environmental Protection Agency, Oregon Department of Environmental Quality.

C. Customer/Partner – investments involving a commitment to a customer, municipality, or co-owner; includes critical service restoration and our obligation to serve; applicable to both sustaining and growth sub-portfolios.

D. Reliability – enhance reliability, resiliency, and security; includes proactive repair/replace in kind projects as well as broader improvements initiatives.

E. Operations – address tools, safety, restoration of non-critical services, and efficiency improvements.

F. Grid Mod – involve new technologies such as energy storage, distribution automation, communications and software, such as advanced distribution management system (ADMS) platforms, which increase visibility, reliability, resilience, and control of the distribution system and Distributed Energy Resources (DERs) within the distribution system. Grid Mod would also include projects that are components of Virtual Power Plan (VPP).

Q. What is included in reserves?

A. Reserve funds are used to address unforeseen grid needs, emergency repairs, or emergent infrastructure requirements that weren't specifically budgeted. These funds provide financial flexibility to respond to urgent situations like equipment failures, severe weather damage, or emerging reliability issues without disrupting planned projects. Reserve funds help PGE maintain system reliability while managing financial risk in the face of uncertainties in grid operations and development.

Q. How are capital projects identified for the distribution system?

A. PGE's capital planning and project prioritization process is designed to ensure that customer and system needs are met through a rigorous, transparent, and forward-looking approach.

Once potential solutions are identified through the Distribution Planning process—based on system needs, technical requirements, and cost-benefit analysis—projects are submitted to the Transmission & Distribution (T&D) Portfolio Team for integration into a comprehensive five-year capital roadmap. The T&D Portfolio Team leads a structured prioritization process that accounts for resource and material availability, risk mitigation, compliance obligations, funding constraints, and customer commitments. Importantly, this process is not conducted in isolation. It incorporates input from key functional partners across the enterprise, including Transmission Planning, Substation Engineering, Property Services, and Distribution Operations Engineering. These groups provide critical expertise to ensure that proposed projects are viable, coordinated across system layers, and aligned with operational realities and long-term strategic goals. The result is a robust and disciplined process that ensures investments are targeted, timely, and deliver maximum value to customers and the grid.

Q. What factors are considered to ensure investments are targeted, timely, and deliver maximum value to customers and the grid?

A PGE's solution identification process for grid needs begins with evaluating existing infrastructure to maximize capacity utilization before considering new investments. The process involves analyzing low-cost solutions utilizing distribution load flow software. The company assesses various solutions options, including upgrading existing infrastructure, site expansions, new substation construction, or non-wire solutions. This process relies on collaboration among several PGE teams, including Transmission and Distribution Planning, Substation Engineering, Property Services, and Distribution Operations Engineering to determine the proposed solutions to meet the grid needs. The Asset Management Planning group conducts economic and cost-benefit analyses, considering multiple data sources such

as historical loading, load forecasts, and known block loads. The distribution planning manager reviews the resulting system study, which provides a recommended solution option, rationale, and cost estimate. This thorough process aims to develop cost-effective, long-lasting solutions with a minimum 10-year lifespan to address capacity issues and system deficiencies, ultimately serving as the foundation for project design and construction scope.

Once the proposed solutions are identified by the Asset Management Planning group as described above, the projects are submitted for funding and consideration to the Capital Review Group (CRG) process, specifically the T&D Business Sponsor Group (BSG)[3] Portfolio Team for funding consideration and development of a five-year capital planning roadmap. Beyond the system technical requirements and cost-benefit analysis performed in the solution identification process, portfolio prioritization will further prioritize and advance projects based on resource availability, material availability, risk, funding availability, compliance and customer commitments.

Q. Describe the benefits these projects bring to the distribution system.

A. Each of the projects in these categories provides a solution to an identified need on the system, which is evolving as the grid requires more consideration for solutions. These solutions must meet faster response times, seamless integration of distribution energy resources, and provide the new digital capabilities that can optimize distributed energy resources (DERs). As needs are identified in one of these categories, projects are analyzed and evaluated to determine the best solution to meet the needs of the system. A robust grid infrastructure unlocks the full

[3] UM 2362, 2024 DSP, Appx. J describes the Capital Review Group (CRG) process for setting the overall capital budget and capital project governance.

potential and value of increased DER adoption while protecting the host customer and the grid.[4]

Q. Briefly describe PGE's grid modernization initiative.

A. PGE is undertaking a multi-year grid modernization effort. This involves integrating new technologies such as enhanced sensors, advanced grid control equipment, telecommunications infrastructure and computing solutions to support the bidirectional flow of energy. Modernizing the grid offers several key advantages, including improved operator awareness, clean energy resource integration and optimization and greater control over transmission and distribution equipment, including both utility and customer-owned distributed energy resources (DER) and flexible loads. This means customers will benefit from a more reliable, resilient, and secure bidirectional grid.[5]

Q. How would approval of PGE's DSM ARM request benefit customers?

A. Improvements in T&D and grid modernization will benefit customers by modernizing and securing the grid and its operations for enhanced reliability, especially by leveraging distributed energy resources. Customers will benefit from projects that support additional capacity and flexibility on the system to meet new and growing customer load, specifically through the implementation of customer solutions that enable electrification of transportation and buildings. Approval of PGE's request helps accelerate decarbonization while maintaining a reliable and resilient integrated grid. It increases safety of the system that serves customers through work performed to meet National Electric Safety Code (NESC), North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) requirements, and all other applicable standards.

[4] UM 2362, 2024 PGE Distribution System Plan, at 25 (Dec. 18, 2024).
[5] *See* https://portlandgeneral.com/about/who-we-are/resource-planning/distribution-system-planning.

Q. Can you give examples of some of the major projects in PGE's request?

A. Yes. Included in this request are forecast plant in service amounts totaling $129.1 million for ongoing overhead distribution replacement work, such as pole and cross-arm replacements on distribution assets, as identified through our overhead Facilities Inspection and Treatment to the National Electric Safety Code (FITNES) program; $37.6 million primarily to replace or upgrade underground cable, driven primarily by the age of the cable, to enhance reliability and mitigate the probability of failures that could cause injury or damage. To address customer needs and growth, $66.8 million for distribution line construction and distribution system maintenance and restoration; $38.8 million for transformers and purchasing and installing customer meters; and $15.2 million for street lighting installations.

Q. Where can more detailed information about projects included in this rate review be found?

A. A complete list of the projects in this filing is provided in PGE Exhibit 201. Consistent with MOU item 8a. of the binding agreements, PGE's work papers included with this filing provide detail by project number demonstrating the exact projects used to create PGE's 2024 DSP Tables 25 and 26, which can be used to match projects provided in PGE Exhibit 201.

Q. For the projects in this rate review, has PGE provided the information required in the Commission's DSP investigatory docket?

A. Yes, PGE Exhibit 201 contains the information for each of the projects in this recovery review, including the information in Docket UM 2005, Order No. 24-421, Section 8. The information included addresses:

1. Project narrative, benefits and needs, asset classes involved and counts, foundational assumptions, risks and mitigations, reason or need for initiation of the project.

2. Project timeline initiation date, estimated completion date, and the type of project: Programs such as pole replacement. Blankets capital to support any development and redevelopment such as enlarging roads; or Projects have a beginning and end date such as distribution, transmission and wildfire projects.
3. Estimation of expenditures and on-going maintenance costs.
4. Description of the analysis of any benefits or risk reduction expected from project in a quantified manner and the value framework-based value determined for the project.
5. Descriptions of alternative solutions considered, proposed asset classes, unit counts, and estimated project costs/expenditure amount for each alternative.
6. Description on if the project interacts with IRP/CEP, WMP, TEP, and/or MYP.
7. Projects impact beyond the distribution system, how will it interact with non-distribution asset strategies, and whether there were any alternatives to distribution investments considered and what were its impact on other network assets.
8. Table including the projected annual costs to implement the action plan.

Q. Please explain why PGE included Order No. 24-421 Section 8 information in this request and not in the DSP itself?

A. PGE's DSP, filed in December 2024, is a forward-looking *plan* of expenditures and not a cost recovery proceeding of projects in service. Projects in the filed DSP were all at different stages in the capital planning and stage-gating process—meaning projects at early planning stages would have updates or changes are the projects move toward execution.[6] These changes are normal in the course of business in managing around timing for availability in materials, delays due to permitting, weather, or other business impacts.

[6] The 2024 DSP filing was based on a project planning forecast from July 2024.

Conversely, this DSP ARM request is for projects, which were in the DSP and have advanced to implementation and are, or will be, fully or partially placed into service by March 31, 2026. As such, they are included in this cost recovery docket, where the prudency of PGE's decisions is determined, prior to a change in customer prices. At this stage, the Section 8 information, should not only be able to be addressed on a project-by-project basis but is foundational in providing the necessary details to assist Staff and stakeholders with their review of these recovery of costs.

Q. Why is the distinction of the DSP as a forward-looking planning process versus the current cost recovery proceeding important?

A. While all projects in this DSP ARM filing originate from the DSP projects (as shown in Tables 25 and 26), and are consistent with MOU binding agreement 8a, the DSP ARM focuses on a smaller subset. Specifically, it only includes projects anticipated to be in service from January 1, 2025, through March 31, 2026. Furthermore, the costs for DSP projects represent only direct, incurred charges, based on when the funds are expected to be spent (cash flow). Conversely, the amounts requested for recovery in this docket are calculated based on project in-service dates and incorporate standard accounting elements such as capital loadings, overheads, and Allowance for Funds Used During Construction (AFUDC). For more detailed information on the application of these loadings, overheads, and AFUDC, please refer to PGE Exhibit 300.

Q. Does PGE plan to update the capital investment amounts during this proceeding?

A. Yes. As is done in other rate review filings, PGE will provide an update to the capital investments in PGE's reply testimony on November 21, 2025.[7] Furthermore, as agreed to in

[7] See PGE Exhibit 101, MOU, Paragraph 15b of the MOU for the Joint Proposed Procedural Schedule.

the MOU, PGE will submit an attestation for all the capital projects identified in this DSP ARM that are in service by March 31, 2026, and will seek the lesser of actual amounts or the original amount in this filing.

III. Qualifications

Q. Joey Baranski, please state your educational background and experience.

A. I received a Bachelor of Science Degree in Electrical Engineering from Portland State University. My employment with PGE started in April 2006 and I have worked as a SCADA Engineer, Substation Technical Services Manager, Manager of Operational Technology Services, Senior Manager of Integrated Engineering Services, Director of Asset Management, and Director of Strategic Grid Planning before moving into my current role as Senior Director of the Project Management Office, BESS Operations, and VPP Operations. Prior to Portland General Electric, I worked as a contractor for PNGC Power.

Q. Kevin Putnam, please state your educational background and experience.

A. I received a Bachelor of Science Degree in Electrical Engineering from the University of Idaho. My employment with PGE started in January 2019 as Manager, Planning, Scheduling and Line Dispatch. I then held the roles of Director, Utility Operations for the Programs, Design and Crew Coordination group and Senior Director, Compliance and Utility Operations, before moving into my current role as Senior Director, Engineering and Design. Prior to joining PGE, I served as Director, Field Engineering at PacifiCorp. I have held other engineering, leadership and field operations management positions at PacifiCorp.

Q. Jack Podlesnik, please state your educational background and experience.

A. I received a Bachelor of Science degree in Electrical Engineering from the University of Wyoming in 2002 and a Masters in Business Administration with an Innovation and Technology Option from Portland State University – School of Business in 2008. I am a registered professional engineer in the state of Oregon since 2011. I joined the Company in 2019 as the Director, Transmission and Distribution Programs, Design and Construction and

have held a variety of management roles overseeing Project Management, Operations Support, Construction Management, Integration Program Management, and Transmission Delivery. My current title is Senior Director, Grid Strategy, Transmission and Planning. In my current role I am responsible for transmission and distribution system planning, regional transmission initiatives, capital budgeting and oversight of transmission projects, distributed device strategy, and economic business development. Prior to joining the Company, I worked at PacifiCorp for nearly sixteen years, last serving as Vice President, System Operations. I serve on the Board of Directors for the Western Energy Institute and am a transmission section council member for the Electric Power Research Institute.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
201C	Confidential DSP ARM Project List and Justification Details

UE 459

Exhibit 201C contains confidential information and has been retained in its native format

Exhibit 201C is protected by General Protective Order No. 23-132

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 459

Application for Distribution System Plan Alternative Rate Mechanism

PORTLAND GENERAL ELECTRIC

Direct Testimony
Revenue Requirements

Greg Batzler, PGE

Stephanie Meeks, PGE

July 25, 2025

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I. Introduction and Overview

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is Greg Batzler. I am employed by PGE as the Manager of Revenue Requirement within Rates and Regulatory Affairs.

My name is Stephanie Meeks. I am employed by PGE as a Regulatory Consultant. Our qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to request the recovery of the revenue requirement of $72.3 million associated with Distribution System Plan (DSP) capital projects forecast to be placed into service from January 1, 2025, through March 31, 2026.

Q. Please provide an overview of the testimony.

A. This testimony describes the components included in PGE's DSP ARM revenue requirement, as provided in PGE Exhibit 301. PGE requests the recovery of the DSP specified capital and the associated costs. This testimony will describe each of the amounts included in the calculation of capital projects, such as capital clearings, loadings and allocations, and allowance for funds used during construction (AFUDC). The included DSP capital and associated costs are a subset of projects from PGE's 2024 DSP filed in December 2024. In addition, the testimony will address any Memorandum of Understanding (MOU) conditions that impact the revenue requirement calculation and how those are included within PGE's request.

Q. Please summarize PGE's request in this testimony.

A. PGE seeks approval for the inclusion of costs for distribution system capital projects in customer rates effective April 1, 2026. The specific capital projects are identified within PGE

Exhibit 201 and discussed in more detail in PGE Exhibits 200 and 201. The revenue requirement for the projects in the DSP ARM includes 2024 DSP capital investments and all the associated costs for those investments, which includes depreciation expense, accumulated depreciation reserve, accumulated deferred income taxes (ADIT), return on the investments, property taxes, and other applicable standard fees and taxes. As a direct offset to these requested amounts and as a condition of the MOU, PGE has also included a significant credit to rate base aligned with the unbundled transmission and distribution (T&D) depreciation expense and deferred tax from PGE's last general rate review, Docket UE 435 (UE 435). This credit acknowledges the reduced net plant value of existing plant amounts included in current customer prices.

II. DSP Capital Amounts and Revenue Requirement Calculation

Q. Please describe the DSP capital amounts included in the revenue requirement.

A. The projects included in this filing are those specified in PGE's 2024 DSP[1] and are discussed further in PGE Exhibit 200. The Gross Plant in the revenue requirement calculation is comprised of the DSP projects that are expected to be placed into service between January 1, 2025, through March 31, 2026. This timeframe is used because the gross plant in the last general rate review included capital additions through December 31, 2024, and the recovery for those amounts are already included in current customer prices. The gross plant in this filing extends through March 31, 2026, as it is one day prior to PGE's requested price effective date of April 1, 2026, and is consistent with the terms specified within the MOU, which specifies in Paragraph 8e that "[c]apital projects can be included in revenue requirement only if in-service on or before March 31, 2026, and will reflect application of Loadings and Overheads and Allowance for Funds Used During Construction (AFUDC) consistent with standard accounting practices and procedures."[2]

Q. Describe the other costs included in the capital investments clearing amounts.

A. When capital investments are placed into service, PGE applies labor loadings, administrative overhead allocations, and AFUDC to capture the full costs of the projects.

Q. What are labor loadings, and how are they applied to capital amounts?

A. Labor loadings, which include items such as paid time off, employee benefits, and injuries and damages, are generally classified and recorded as Administrative & General (A&G) costs per Federal Energy Regulatory Commission (FERC) and Generally Accepted Accounting

[1] *PGE's 2024 Distribution System Plan*, Dkt. No. UM 2362.
[2] *See* MOU, PGE Exhibit 101, Binding Agreements – Paragraph 8e

Principles (GAAP) accounting rules. However, for labor that is charged to capital accounts (and other specified accounts including non-utility), associated labor loadings are applied. The allocation methodology generally distributes these costs proportionately to actual direct labor charges in specified Cost Elements, Accounts, Accounting Work Orders, and Operating Units. Most loadings apply only to straight-time labor charges, with exceptions for Payroll Taxes and Injuries & Damages, which apply to premium time and overtime, in addition to straight-time labor.

Q. What are administrative overheads and how are they applied to capital amounts?

A. Administrative overheads reflect the planning, design, engineering, supervision, and administrative activities that benefit construction projects but are not otherwise charged directly. These administrative and overhead amounts are allocated and loaded to capital projects using underlying "driver" accounts, departments, and cost elements. Per FERC requirements, projects bear an equitable share of these overhead costs.

Q. How is AFUDC calculated and applied to capital projects?

A. AFUDC is added to the final plant values for each project and is calculated in accordance with FERC guidance in 18 C.F.R. pt. 101 Electric Plant Instruction. PGE calculates AFUDC rates on a monthly basis utilizing balances and applicable cost levels, as of the end of the preceding month, for all components of capital, and utilizing estimates of construction work in progress balances and short-term debt balances and cost rates in the month that the AFUDC rate is to be used.

Q. Paragraph 8f of the MOU states that PGE will demonstrate that loading rates are consistent with the loading rates as applied in UE 435. Has PGE complied with this provision of the MOU?

A. Yes. PGE has performed an analysis of the loadings and overheads applied as a percentage of forecast T&D capital spend over the period January 1, 2024 through December 31, 2024 using the UE 435 capital forecast version and compared to the percentage of loadings and overheads applied to forecast T&D capital spend from January 1, 2025 through March 31, 2026 using the DSP ARM capital forecast version. The results of this analysis show that the ratio of labor loadings and other overheads as a percentage of total capital spend is consistent between the two forecast versions. This analysis, which is summarized below in Table 1, is included as part of our work papers.

Table 1
Overheads and Loadings as a Percent of Forecast T&D Capital Spend

	2025 Capital Forecast[1] 01/01/2025-03/31/2026	UE 435 Capital Forecast 01/01/2024-12/31/2024	2025 vs 2024
Labor Loading Percent[2]	61%	60%	1%
Other Overheads Percent[3]	37%	35%	2%
Total Overheads Percent[4]	39%	37%	2%

1. capital budget utilized for DSP ARM request
2. sum of labor loadings / Total incurred labor
3. sum of other overheads / sum of total incurred non-labor
4. sum of all loadings and overheads / sum of total incurred capital

Q. Why are you comparing capital spend amounts versus looking at capital closings?

A. Loadings and overheads are applied on a monthly basis to amounts incurred. Thus, for an apples-to-apples comparison of loadings and overheads between years it is critical to fix the period you are reviewing. This is not possible to do when looking at capital closings, as projects placed into service can include capital spend spanning multiple years. By reviewing spend between these two forecast versions and focusing on the applicable periods, you can accurately compare loading rates between years.

Q. Why are you focusing on comparing T&D projects between years?

A. We focus on T&D projects for two reasons. First, the majority of DSP ARM projects fit into the T&D spending category. Second, focusing on T&D between the two forecast versions and time periods creates an apples-to-apples comparison. If comparing projects included in the DSP ARM to T&D included within UE 435 you will have two different bases, which creates a skewed result.

Q. Paragraph 8f also states that "PGE's Loadings and Overheads and AFUDC policies must be supported in PGE testimony." Has PGE complied with this binding agreement?

A. Yes. We discuss the basis of labor loadings, administrative overheads, and AFUDC above and PGE Exhibit 302 provides the 2024 Cost Allocation Manual describing the method for applying loadings and overheads to end-use accounts, and which was most recently provided as part of Docket RE 64, PGE's Annual Affiliated Interest Report. Additionally, we provide as PGE Exhibit 303 a copy of PGE's Capital Accounting Policy, along with an opinion letter from PGE's auditor (Deloitte and Touche), which indicates that PGE's financial statements "present fairly, in all material respects" and that the results of PGE's operations are "in conformity with accounting principles generally accepted in the United States of America" and that in their opinion, PGE "maintained in all material respects, effective internal control over financial reporting as of December 31, 2024, based on criteria established in Internal Control — Integrated Framework (2013) issued by COSO."

Q. Has PGE made any adjustments to rate base amounts in this filing in order to "balance the need for PGE to bring new investments into rates with the opportunity to capture for customers other costs that have decreased,"[3] as recommended by the Commission in UE 435?

A. Yes. Paragraph 8g of the MOU specifies that "PGE must forecast depreciation reserve and ADIT offsets to DSP rate base through March 31, 2026." And that [r]eserve offsets will be aligned with UE 435 final approved unbundled depreciation expense for distribution and transmission functionalized assets." By doing this PGE effectively credits back to customers the accumulated depreciation and ADIT benefits that PGE is receiving from these assets currently included in customer prices in between general rate reviews. The total rate base credit amount associated with UE 435 depreciation included in our filed revenue requirement is approximately $270.3 million, while the UE 435 ADIT benefit credited back to customers totals approximately $34.0 million. These credit amounts represent a significant reduction to the total rate base value associated with DSP projects, amounting to a revenue requirement reduction of approximately $28.2 million.

Q. What are the forecast costs associated with DSP ARM Capital?

A. PGE's forecast for DSP ARM capital consists of the following major categories:

- Rate base totals approximately $316.5 million, which includes gross plant of approximately $655.0 million, accumulated depreciation and accumulated deferred income tax through March 31, 2026, of approximately ($34.0 million) and ($0.9 million) respectively. Additionally, the depreciation and deferred tax roll off amounts from

[3] *PGE's Request for a General Rate Revision*, UE 435, OPUC Order No. 24-454, at 45.

UE 435, which are credited to accumulated depreciation and ADIT total approximately ($270.3 million) and ($34.0 million) respectively.

- Annualized depreciation expenses total approximately $33.6 million and are consistent with the parameters and depreciation values included in PGE's 2021 depreciation study (Docket UM 2152), approved by Commission Order No. 21-463.
- The annualized property tax forecast for the DSP ARM capital totals approximately $9.3 million.
- The other additional costs, such as franchise and OPUC fees and income taxes of approximately $7.2 million, brings the total revenue requirement to approximately $72.2 million.
- There is no associated Operations & Maintenance nor Administrative & General costs included in this filing for recovery.

III. Comparison of the DSP ARM to a GRR

Q. Describe how this filing compares to a general rate review.

A. The calculations in this filing follow the same methods to calculate the revenue requirement as it would in a general rate review. The difference in this filing is the limitation on the elements that are being requested for recovery, which specifically are certain additional capital investments and the associated costs with those investments. Additionally, subject to the terms of the MOU, PGE has provided a significant rate base credit associated with T&D projects included within existing current prices. This narrow and transparent approach balances cost recovery with sensitivity to customer affordability by avoiding the upward rate pressure of more expansive general rate reviews. The DSP ARM thus strikes a meaningful balance: it addresses the need for modern, resilient grid investments while supporting customer affordability through regulatory efficiency and financial discipline.

IV. Qualifications

Q. Greg Batzler, please state your educational background and experience.

A. I received a Bachelor of Arts degree in Radio and Television from San Francisco State University in 1997 and a Master of Business Administration degree from Marylhurst University in 2011. I have been employed at PGE since 2006, working in various departments including Meter Reading and Human Resources. I have worked in the Rates and Regulatory Affairs department since 2012. I became the Manager of Revenue Requirement within Rates and Regulatory Affairs in April 2025.

Q. Q. Stephanie Meeks, please state your educational background and experience.

A. I received a Bachelor of Science degree in Accounting from National American University in 2002. I joined PGE in April 2024, working as a Regulatory Consultant in the Rates and Regulatory Affairs. I have worked at a combination of electric and gas utilities since 2006 in various positions including Revenue Requirements Senior Analyst, Utility Gross Margin Manager, and Regulatory Manager.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
301	Distribution System Plan Annualized Revenue Requirement
302	2024 Cost Allocation Manual
303	Capital Accounting Policy & Auditor Statement

UE 459

Exhibit 301 has been retained in its native format

PORTLAND GENERAL ELECTRIC
COST ALLOCATION MANUAL
FOR THE YEAR 2024

Attachment 2

PORTLAND GENERAL ELECTRIC COMPANY

2024 Cost Allocation Manual

per

OAR 860-027-0048(6)

(Reported May 2025)

UE 459 / PGE / 302
Batzler - Meeks / 2

PORTLAND GENERAL ELECTRIC
COST ALLOCATION MANUAL
FOR THE YEAR 2024

Introduction

This document contains PGE's 2024 Cost Allocation Manual along with a reference of actual allocation activity pertinent to the nature of this Affiliated Interest Report for the year 2024. Actual loadings, costs, allocations, and other factors have been summarized separately for inclusion of the final, complete 2024 Cost Allocation Manual these numbers relate to.

***There has been no change in the nature of the actual values provided within from prior years' filings.**

Following is a discussion of PGE's loadings, allocations and the respective methodologies that are used to redistribute costs to non-regulated activities and affiliates. For some services, typically those that benefit various functional areas, it is not practicable to charge the cost directly. Costs that cannot be reasonably directly charged are captured either on the balance sheet through deferred accounts or in specific income statement accounts. These costs are then redistributed to their ultimate destination.

PGE uses a series of automated reclassifications and loadings to distribute administrative and overhead costs to end use accounts. There are four groups of these: 1) Labor Loadings, 2) Service Provider Allocations, 3) Administrative Overheads, and 4) Other Allocations.

Within the above allocations, numerous costs are distributed to and from Administrative and General (A&G) ledgers, generally FERC accounts 920 and 921. Most A&G costs are not fully allocated. Some A&G accounts are not allocated at all, while others are only allocated in part. With the exception of Paid Time Off (PTO), A&G allocations apply largely to capital and deferred (balance sheet) accounts, and to operations and maintenance (O&M - income statement) accounts in limited circumstances. Consequently, the amounts remaining in A&G represent the unallocated costs related to O&M. The reason for this approach is to comply with FERC reporting requirements (see the Interpretations of Uniform System of Accounts for Electric, Gas and Water Utilities, as revised February 27, 1981). Costs that are applicable to construction work should be directly assigned or allocated to capital. Those that are not related to capital work remain in A&G according to their FERC designation. Note, see the discussion below regarding the exception for Service Provider allocations.

In accordance with FERC, "wherever allocations are necessary in order to arrive at the amount to be included in any accounts, the method and basis of allocation shall be reflected by underlying records" (CFR, Title 18, Pt. 101).

PORTLAND GENERAL ELECTRIC
COST ALLOCATION MANUAL
FOR THE YEAR 2024

PGE's Non-Regulated Activities

Non-Regulated Activities:

- Large Nonresidential Tradable Renewable Credit Rider (Schedule 54)
- Meter Information Services (Schedule 320)
- Electrical Equipment Services (Schedule 715)

PGE Affiliates and Subsidiaries

Affiliates:

- Portland General Electric Foundation – Corporate foundation of PGE.

Subsidiaries:

- 121 SW Salmon Street Corporation – 121SWS owns the World Trade Center buildings, where PGE has its headquarters. 121SWS charges PGE rent based on PGE's percentage of occupancy of the rentable space in WTC multiplied by WTC operating expenses. PGE charges 121SWS labor costs based on man-hours utilized at fully allocated labor rates. Non-labor items are billed at cost. All profits/losses from 121SWS are retained at 121SWS.

- World Trade Center Northwest Corporation – Inactive except for holding the World Trade Center franchise.

- Salmon Springs Hospitality Group, Inc. – SSHG provides catering within the WTC complex. SSHG charges PGE market rate for catering but discounts the charge for room rental. PGE charges SSHG labor costs based on man-hours utilized at fully allocated labor rates. Non-labor items are billed at cost, with the exception of office space, which is billed at market value. All profits from SSHG flow back to PGE (regulated). SSHG ceased operation in 2022.

Finance Data Governance – Cost Allocation Manual

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Overview

PGE uses a series of automated reclassifications and loadings to distribute certain administrative and overhead costs to end use accounts. These can be categorized into four groups:

1. Labor Loadings
2. Service Providers
3. Administrative Overheads
4. Other Overheads

Please note, costs that are applicable to construction work should be directly assigned or allocated to capital. Those that are not related to capital work remain in O&M according to their FERC designation. See the discussion below regarding the exception for Service Provider allocations.

In accordance with FERC, "wherever allocations are necessary in order to arrive at the amount to be included in any accounts, the method and basis of allocation shall be reflected by underlying records" (CFR, Title 18, Pt. 101).

In January 2024, PGE switched the operating system from PowerPlan to Oracle EPCM for running allocations. Some allocations changed from year to year. This manual reflects allocation rules in place for the 2024 Fiscal Year. Please refer to prior versions of this file for earlier years.

Labor Loadings

Labor-related costs that cannot be directly assigned to "productive" or "end-use" accounts are "loaded" to productive/end-use accounts via a series of labor loading allocations based on direct labor costs. The labor-related costs incurred to date are allocated proportionately to the actual direct labor costs in specified accounts and other accounting string elements.

There are 10 categories of labor loadings:

1. Paid Time Off
2. Corporate Incentives
3. Payroll Taxes
4. Other Post-Employment Benefits (OPEB) – Service Cost
5. Other Post-Employment Benefits (OPEB) – Non-Service Cost
6. Pension Service Cost
7. Pension Non-Service Cost
8. Employee Benefits
9. Injuries & Damages

Please note: these labor-related A&G costs are allocated to direct labor charges to all accounts; however, per FERC and GAAP accounting rules, all non-PTO costs are pulled back to A&G from all accounts, except for the following:

- Construction Work in Progress
- Retirements
- Materials and Supplies (i.e., inventory)
- Other Noncurrent assets (i.e., suspense)
- Asset Retirement Obligations (i.e., trojan decommissioning)

- Non-Utility O&M
- Transmission Study costs (for billing purposes)
- Any O&M account that received certain service provider allocations.
- Reg assets/liabilities (not for Injuries & Damages or Corporate Governance)

Service Providers

It is not practical or cost-effective to maintain corporate service expertise in each area of the company. Accordingly, service groups are formed to provide these services to all organizations within the company. PGE has several departments that provide services for the benefit of the other functional areas of the company. These services include the following:

- World Trade Center (WTC) facilities management
- Air and fleet vehicle transportation services
- Information processing, telecommunications, and computer hardware and software support

Except for WTC, FERC account 184 serves as the allocation "base" that accumulates costs. Departments whose functions fall within the services listed above charge their time and expenses to this account. The total costs are then reclassified (or allocated) to those functional areas of the company receiving the services.

Currently, the Service Provider cost allocations include:

1. WTC Floorspace
2. Helicopter
3. Enterprise IT Service Provider
4. Utility Operations IT Service Provider
5. Fleet Services (TRANSPORTATION)

Service Provider allocations and the loadings thereon are distributed to various income statement accounts outside of the general rule associated with capital and non-utility accounts and all co-owner accounts. These costs are distributed to reflect the fully allocated cost of the services provided in a manner similar to the results of services provided by a third party. This approach recognizes the full value of the service groups to the user groups and reflects the costs of these services in the income statement line items where the services are used.

Administrative Overheads

PGE utilizes a series of system allocations to reclassify various pools of administrative services that support functional areas of the company in both capital and O&M work activities. Thus, these administrative expenses are allocated out as an overhead cost to capital, utility, non-utility and the co-owned generation plants. These allocations use data from underlying "driver" account(s) for the purpose of calculating the relative proportion to apply to the summary of "balance" (source) costs. The balance costs are in turn multiplied by the calculated rates to determine the dollar values to reclassify.

The various pools of administrative overhead allocations include:

1. Corporate A&G (Corporate Governance)
2. Generation Engineering Support
3. Transmission & Distribution Plan, Analyze, and Design (PAD)
4. Distribution Admin Overhead (DOSE)

5. Transmission Admin Overhead (TOSE)

In addition, there are some other administrative overheads related to materials and inventory:

1. Line Expendables
2. Substation Expendables
3. Materials Overhead

Other Allocations

There're miscellaneous allocations related to the co-owner of generation plants as well as dividend:

1. PGE Share: the co-owner credit entry
2. Plant: the co-owner credit entry for specific capital jobs
3. Dividend Close: reclass from retained earnings to undistributed earnings.

Key Allocation Terms

Source

The allocation source, also known as the “Allocation Balance,” is an account or set of accounts that provides the total amount to be allocated for an allocation.

Driver

The allocation driver provides the criteria for how and how much of the allocation source is distributed.

Destination

The allocation destination provides the criteria for where the allocation balance is distributed.

Offset

The allocation offset can be either a clearing account or an allocation credit account.

A clearing account is the account in which we collect costs, then fully allocate them to other accounting strings each period. The offsetting credit goes to the same account as the expenses. Clearing accounts are all FERC 184 accounts. An allocation credit account records the amount that was allocated from the balance. Both balance and credit accounts roll up within the same FERC designation.

Allocation Run Sequence

1 Labor Loadings
   a. Paid Time Off
   b. Corporate Incentives
   c. Payroll Taxes
   d. OPEB – Non-Service Cost
   e. OPEB – Service Cost
   f. Pension Service Cost
   g. Pension Non-Service Cost
   h. Employee Benefits
   i. Injuries & Damages

2 Service Providers
   a. WTC Floorspace
   b. Helicopter
   c. Enterprise IT Service Provider
   d. Utility IT Service Provider
   e. Fleet Transportation

3 Administrative Overheads
   a. Corporate A&G
   b. Generation Engineering
   c. PAD
   d. DOSE
   e. TOSE

4 Other Administrative Overheads
   a. Line Expendables
   b. Substation Expendables
   c. Material Overhead

5 Other Allocations
   a. PGE Share
   b. Plant
   c. Dividend Close

Labor Loadings

Allocation Methodology:
Labor loadings are mostly allocated to straight-time labor charges, using a fixed percentage rate determined during the annual budget process. The fixed rate is based on the budgeted labor loading cost as a percentage of budgeted labor.

Each month, any variance between the fixed rate and the actual rate is applied to department 806, HR's transfer department. This removes the variability of the labor loadings at the department level that are outside of the manager's control.

Paid Time Off (PTO)

Cost Element: 5104

Definition: Paid Time Off (PTO) consists of employee pay for vacation, holiday, sick leave, and funeral leave. Costs for vacation pay include amount taken as well as an accrual of earned vacation, while costs for holiday, sick and funeral leave are expensed as taken. PTO is the only A&G expense that is fully allocated to balance sheet and income statement accounts.

Loadings Criteria:

	Source	Driver	Destination	Offset
Entity	PGE01	*	Same as driver	PGE01
Unit	18100	*	Same as driver	18100
Account	1840017	<>1840017	Same as driver	1840017
Department	*	*	Same as driver	Same as Source
Cost Element	<> 5104	1101,1102,1103	5104	5104
AWO	*	*	Same as driver	2000013300

Corporate Incentives

Cost Element: 5103

Definition: The Corporate Incentive loadings represent the cost of PGE's general incentive pay program that is incurred in the Performance Incentive Compensation accounts. Please note, the Corporate Incentive program does not include the following generating facilities, because they have their own incentive programs:

- Coyote Springs (Unit 16100, 86100, 95500 and 95599)
- Port Westward I (Unit 16400 and 16600)
- Carty (Unit 16800)
- Biglow (Unit 17200)

- Tucannon (Unit 17400)
- Wheatridge (Unit 17500)
- Trojan (Unit 91100)
- Boardman (Unit 92100)
- Pelton Round Butte (Unit 96100 and 99100)

Loadings Criteria:

	Source	Driver	Destination	Offset
Entity	PGE01	*	Same as driver	PGE01
Unit	18100	<> Units listed above	Same as driver	18100
Account	9200004, 9200005, 9210004, 9210005	<> Source Accounts	Same as driver	9220003
Department	*	*	Same as driver	Same as Source
Cost Element	*	1101,1103	5103	5103
AWO	*	*	Same as driver	2000013301

Payroll Taxes

Cost Element: 5106

Definition: The Payroll Tax loading consists of employer-paid, labor-related taxes such as FICA (Social Security & Medicare), federal unemployment, state unemployment, and SIAC (workers' compensation premiums). For accounting purposes, incurred payroll taxes are classified as Taxes Other Than Income Taxes. However, it is appropriate to capitalize a portion of these costs as they relate to direct labor costs that have been capitalized.

Loadings Criteria:

	Source	Driver	Destination	Offset
Entity	PGE01	*	Same as driver	PGE01
Unit	18100	*	Same as driver	18100
Account	4081004, 4081005, 4081006, 4081007, 4081008	<> Source Accounts	Same as driver	4081009
Department	*	*	Same as driver	Same as Source
Cost Element	*	11*, 12*, 14*, 1501, 1601	5106	5106
AWO	*	*	Same as driver	2000013302

Other Post-Employment Benefits (OPEB)

Cost Element: 5112 OPEB Service; 5117 OPEB Non-Service

Definition: OPEB allocation includes the actuarial cost component of Other Post Employment (retirement) Benefit (OPEB) loading. For SEC/GAAP purposes, only the service cost can be capitalized, therefore the labor loadings for OPEB is split into a non-service cost loading and a service cost loading.

Loadings Criteria:

- **OPEB Non-Service Cost:**

	Source	Driver	Destination	Offset
Entity	PGE01	*	Same as driver	PGE01
Unit	18100	*	Same as driver	18100
Account	9260032	<> 9260032	Same as driver	9260037
Department	*	*	Same as driver	Same as Source
Cost Element	*	1101,1102,1103	5117	5117
AWO	*	*	Same as driver	2000013303

- **OPEB Service Cost:**

	Source	Driver	Destination	Offset
Entity	PGE01	*	Same as driver	PGE01
Unit	18100	*	Same as driver	18100
Account	9260031	<> 9260031	Same as driver	9260036
Department	*	*	Same as driver	Same as Source
Cost Element	*	1101,1102,1103	5112	5112
AWO	*	*	Same as driver	2000013304

Pension Service Cost

Cost Element: 5101 Pension Service; 5118 Pension Non-Service

Definition: Pension service cost allocation includes service cost component and non-service cost component. For SEC/GAAP purposes, only the service cost component of the actuarial costs can be capitalized, therefore the labor loadings for pension have been split into a service cost loading and a non-service cost loading.

Loadings Criteria:

- **Pension Non-Service Cost**

	Source	Driver	Destination	Offset
Entity	PGE01	*	Same as driver	PGE01
Unit	18100	*	Same as driver	18100
Account	9260002	<> 9260002	Same as driver	9260027
Department	*	*	Same as driver	Same as Source
Cost Element	*	1101, 1102, 1103	5118	5118
AWO	*	*	Same as driver	2000013309

- **Pension Service Cost**

	Source	Driver	Destination	Offset
Entity	PGE01	*	Same as driver	PGE01
Unit	18100	*	Same as driver	18100
Account	9260001	<> 9260001	Same as driver	9260024
Department	*	*	Same as driver	Same as Source
Cost Element	*	1101, 1102, 1103	5101	5101
AWO	*	*	Same as driver	2000013305

Employee Benefits

Cost Element: 5105

Definition: The Employee Benefits loading includes the costs for retirement savings, health, dental, disability, life insurance, and education & recreation programs. For accounting purposes, these costs are classified as A&G costs. However, it is appropriate to capitalize a portion of these costs as they relate to direct labor costs that have been capitalized.

Loadings Criteria:

	Source	Driver	Destination	Offset
Entity	PGE01	*	Same as driver	PGE01
Unit	18100	*	Same as driver	18100
Account	9260003, 9260004, 9260005, 9260008,9260009, 9260011, 9260013, 9260014, 9260016, 9260017, 9260018, 9260019, 9260020, 9260021, 9260022	<> Source Accounts	Same as driver	9260015
Department	*	*	Same as driver	Same as Source
Cost Element	*	1101, 1102, 1103	5105	5105
AWO	*	*	Same as driver	2000013312

Injuries & Damages

Cost Element: 5107

Definition: The Injuries & Damages loading includes the cost of administering PGE's health and safety programs plus claims from general liability damages, workers' compensation injuries, and auto accidents.

Please note, since most injuries and damages occur in fieldwork, the labor basis is reduced by office groups and A&G workers. Consequently, the allocation is weighted to field operation and construction work by excluding the following accounts from the driver basis:

- All Service Provider source accounts (i.e., IT Service Provider)
- Non-Utility O&M
- Customer Expense
- A&G Expense

Loadings Criteria:

	Source	Driver	Destination	Offset
Entity	PGE01	*	Same as driver	PGE01
Unit	18100	*	Same as driver	18100
Account	9250001, 9250003	<> Source Accounts, <> Service Providers, <> Non-Utility O&M, <> Customer Expense, <> A&G Expense	Same as driver	9250004
Department	*	*	Same as driver	Same as Source
Cost Element	*	11*, 12*, 14*, 1501, 1601	5107	5107
AWO	*	*	Same as driver	2000013313

Service Providers

WTC Floorspace

Cost Element: 5206

Definition: PGE leases its corporate headquarters office at the World Trade Center (WTC) from 121 SW Salmon Street Corporation (121SWS), a PGE subsidiary. Portions of the WTC are leased to third parties (non-PGE tenants). The purpose of this allocation is to allocate PGE's base rent and share of the operating and maintenance costs of WTC between PGE functional areas which utilize the WTC complex.

Operating costs include security, general maintenance, cleaning, administration, licenses and fees, utilities, property taxes, insurance, and depreciation.

Allocation Methodology: A monthly recurring entry, SWSREV, records PGE's base rent and its share of operating expenses, based on PGE's percentage of occupancy of the rentable space in the WTC buildings. The amount recorded to PGE is then split between utility portion and non-utility portion according to the annual space study done by WTC property management. The utility portion is allocated into the Corporate A&G (Corporate Governance) allocation pool. The remaining portion is allocated to non-utility expense.

Allocation Criteria:

	Source	Driver	Destination	Offset
Entity	PGE01	PGE01	PGE01	PGE01
Unit	18100	18100	18100	18100
Account	4180900	4171008 (Non-utility % of rent) 9200001 (Utility % of rent)	same as Driver	4180007
Department	*	*	Same as Source	Same as Source
Cost Element	*	*	5206	5206
AWO	*	*	2000013314	2000013314

* See Appendix A for fixed allocation percentage that is applied to accounts noted in the driver.

Helicopter

Cost Element: 5203

Definition: The costs associated with the corporate helicopter allocation include the operations and maintenance of the helicopter (i.e., pilot, fuel, required training, travel expenses, etc.) as well as the depreciation of the aircraft asset.

Allocation Methodology: An annual survey is performed to decide the fixed percentage allocated to Transmission, Distribution and Wildlife based on pilot's mission flight hours of prior year. To appropriately allocate the operational and maintenance costs of the corporate helicopter to the various areas of the company that utilize its services.

Allocation Criteria:

	Source	Driver	Destination	Offset
Entity	PGE	PGE01	Same as Driver	PGE01
Unit	18100	18100, 15200, 99100	Same as Driver	18100
Account	1840002	5710001, 5710002, 5710004, 5930001, 5370002	Same as Driver	1840002
Department	*	*	Same as Source	Same as Source
Cost Element	<> 5203	*	5203	5203
AWO	*	*	2000013315	2000013315

* See Appendix A for fixed allocation percentage that is applied to accounts noted in the driver.

Enterprise IT

Cost Element: 5201

Definition: Enterprise IT includes the operational and maintenance costs of providing the following services:

- Operational and developmental support to end-user application systems (software),
- Develops, operates, and maintains mainframe and LAN computer systems and telecommunication equipment,
- Manages the overall direction for information system and technology issues.

Allocation Methodology: Enterprise IT is allocated dynamically based on all PGE incurred O&M labor across the company. It does not directly allocate to capital. However, it flows to capital indirectly through administrative overhead allocations (i.e., DOSE, PAD, Corporate Governance, etc.).

Allocation Criteria:

	Source	Driver	Destination	Offset
Entity	PGE	*	Same as Driver	PGE01
Unit	18100	*	Same as Driver	18100
Account	1840004	All Net Income Accounts, Trojan ARO, Generation Engineering Support Source Account, PAD Source Account, DOSE and TOSE Source Accounts	Same as Driver	1840004
Department	*	*	Same as Source	Same as Source
Cost Element	<> 5201	1101, 1102, 1103, 1501, 1502	5201	5201
AWO	*	<> Wildfire Mitigation, <> Labor Loading Ony Projects	Same as Driver	2000013316

Utility Operations IT

Cost Element: 5221

Definition: Utility Operations IT is specifically related to the operation of Generation, Transmission and Distribution. It includes the operational and maintenance costs of providing the following services:

- Operational and developmental support to end-user application systems (software),
- Develops, operates, and maintains mainframe and LAN computer systems and telecommunication equipment,
- Manages the overall direction for information system and technology issues.

Allocation Methodology: Utility Operations IT is allocated dynamically based on all PGE incurred labor in transmission, distribution, and generation. It does not directly allocate to capital. However, it flows to capital indirectly through administrative overhead allocations (i.e., DOSE, PAD, Corporate Governance, etc.).

Allocation Criteria:

	Source	Driver	Destination	Offset
Entity	PGE	*	Same as Driver	PGE01
Unit	18100	*	Same as Driver	18100
Account	1840033	Transmission, Distribution and Generation Expenses, DOSE and TOSE source accounts	Same as Driver	1840033
Department	*	*	Same as Source	Same as Source
Cost Element	<> 5221	1101, 1102, 1103, 1501, 1502	5221	5221
AWO	*	Transmission Projects, Distribution Projects or Generation projects; <> Wildfire Mitigation, <> Labor Loading Ony Projects	Same as Driver	2000013316

Fleet Transportation

Cost Element: 5301

Definition: Fleet Transportation is the labor and expenses of the Fleet and Garage Operations organization that maintains the company's vehicle fleet as well as the depreciation expense associated with the vehicle assets.

Allocation Methodology: Prior to allocation runs, a recurring JE (JAL32A) is recorded each month to allocate out fixed fee of non-T&D assigned vehicles. The remaining balance in transportation source pool is then allocated dynamically based on straight time labor of T&D line and substation crews and eagles.

Allocation Criteria:

	Source	Driver	Destination	Offset
Entity	PGE	*	Same as Driver	PGE01
Unit	18100	*	Same as Driver	18100
Account	1840001	<> Service Provider accounts, <> Suspense Accounts, <> Customer Expense, <> A&G Expense	Same as Driver	1840001
Department	*	T&D Line Crews, Substation Crews, Eagles	Same as Source	Same as Source
Cost Element	<> 5301	1101, 1102, 1103	5301	5301
AWO	*	Transmission Projects, Distribution Projects; <> Wildfire Mitigation, <> Labor Loading Ony Projects	Same as Driver	2000013322

Administrative Overheads

Corporate A&G Labor

Cost Element: 5204

Definition: Incurred labor costs for activities such as Human Resources, Accounting, and other corporate functions that support all of PGE's activities are distributed to PGE's capital, non-utility and the co-owned entities. Activities charged to the corporate governance allocation accounts have been identified as supporting all of PGE, including the generating plant co-owners.

Allocation Methodology: Corporate A&G labor is allocated out dynamically based on incurred labor across company. In addition, the capital allocated from Corporate A&G labor is trued up based on the capital rate resulted from a PWC time study. The true-up pool is the allocable A&G labor plus non-allocable A&G labor (9200001, 9200002, 9200009).

Allocation Criteria:

	Source	Driver	Destination	Offset
Entity	PGE	*	Same as Driver	PGE01
Unit	18100	*	Same as Driver	18100
Account	9200001, 9200009	<> Source accounts, <> Service Provider accounts, <> Labor Loading source accounts	Same as Driver	9220001
Department	*	*	Same as Source	Same as Source
Cost Element	<> Service Provider CEs	1101, 1102, 1103, 1501	5204	5204
AWO	*	<> Wildfire Mitigation, <> Labor Loading Only Projects	Same as Driver	2000013318

Corporate A&G Non-labor

Cost Element: 5214

Definition: Incurred non-labor costs for activities such as Human Resources, Accounting, and other corporate functions that support all of PGE's activities are distributed to PGE's capital, non-utility and the co-owned entities. Activities charged to the corporate governance allocation accounts have been identified as supporting all of PGE, including the generating plant co-owners.

Allocation Methodology: Corporate A&G non-labor is allocated out dynamically based on incurred labor across company.

Allocation Criteria:

	Source	Driver	Destination	Offset
Entity	PGE	*	Same as Driver	PGE01
Unit	18100	*	Same as Driver	18100
Account	9210001, 9210009, 9230002	<> Source accounts, <> Service Provider accounts, <> Labor Loading source accounts	Same as Driver	9220001
Department	*	*	Same as Source	Same as Source
Cost Element	<> Service Provider CEs	1101, 1102, 1103, 1501	5214	5214
AWO	*	<> Wildfire Mitigation, <> Labor Loading Only Projects	Same as Driver	2000013318

Generation Engineering Support

Cost Element: 5210

Definition: The incurred charges within the Generation Engineering Overhead allocation represent engineering supervision, planning, design and engineering support function expenses.

Allocation Methodology: Generation Engineering Support is allocated according to the Straight time labor of Generation Engineers (Department 551) specifically working on generation projects.

Allocation Criteria:

	Source	Driver	Destination	Offset
Entity	PGE	*	Same as Driver	PGE01
Unit	18100	*	Same as Driver	18100
Account	1840015	Capital, Trojan ARO, Generation Expense	Same as Driver	1840015
Department	*	551	Same as Source	Same as Source
Cost Element	<> 5210	1101	5210	5210
AWO	*	Generation Projects; <> Wildfire Mitigation, <> Labor Loading Only Projects	Same as Driver	2000013319

Plan, Analyze, and Design (PAD)

Cost Element: 5208

Definition: The cost of labor and expenses incurred in the design and engineering of distribution capital assets.

Allocation Methodology: “PAD” activities are exclusively in support of capital projects. The PAD allocation allocates all of the PAD costs across the T&D capital projects.

Allocation Criteria:

	Source	Driver	Destination	Offset
Entity	PGE	PGE01	Same as Driver	PGE01
Unit	18100	*	Same as Driver	18100
Account	1840016	1070001	Same as Driver	1840016
Department	*	*	Same as Source	Same as Source
Cost Element	<> 5208	11*, 12*, 14*, 15*, 16*, 22*	5208	5208
AWO	*	Transmission Capital, Distribution Capital, <> Wildfire Mitigation, <> Labor Loading Only Projects	Same as Driver	2000013321

Distribution Admin Overhead (DOSE)

Cost Element: 5205

Definition: The allocation includes the costs of the departments that directly support the daily activities of the line crews working on the distribution network. For transparency, the allocation has been broken into six functions:

- **Distribution System**
- General Supervision & Support
- Engineering & Design
- Load Dispatch
- Operations Technology

- **Distribution Line**
- Line Crew Supervision, Support & Misc. Operations

- **Distribution Substation**
- Substation Crew Supervision, Support, Misc. Operations, etc.

Allocation Methodology: The costs incurred within the DOSE allocation pool(s) are allocated out based on where PGE's line crews and contract crews charged their straight time to distribution capital and O&M projects.

Allocation Criteria:

Distribution System - General Supervision & Support

	Source	Driver	Destination	Offset
Entity	PGE	PGE01	Same as Driver	PGE01
Unit	18100	18100	Same as Driver	18100
Account	1840020	1070001, Distribution Operations (58%), Distribution Maintenance (59%)	1070001, 5800013 (Operations), 5900013 (Maintenance)	1840020
Department	*	T&D Line and Substation Crews	Same as Source	Same as Source
Cost Element	<> 5205	1102, 1502	5205	5205
AWO	*	Distribution Projects, <> Wildfire Mitigation, <> Labor Loading Only Projects	Same as Driver	2000013323

Distribution System - Engineering & Design

	Source	Driver	Destination	Offset
Entity	PGE	PGE01	Same as Driver	PGE01
Unit	18100	18100	Same as Driver	18100
Account	1840021	1070001, Distribution Operations (58%), Distribution Maintenance (59%)	1070001, 5800014 (Operations), 5900014 (Maintenance)	1840021
Department	*	T&D Line and Substation Crews	Same as Source	Same as Source
Cost Element	<> 5205	1102, 1502	5205	5205
AWO	*	Distribution Projects, <> Wildfire Mitigation, <> Labor Loading Only Projects	Same as Driver	2000013323

Distribution System - Load Dispatch

	Source	Driver	Destination	Offset
Entity	PGE	PGE01	Same as Driver	PGE01
Unit	18100	18100	Same as Driver	18100
Account	1840022	1070001, Distribution Operations (58%), Distribution Maintenance (59%)	1070001, 5810001	1840022
Department	*	T&D Line and Substation Crews	Same as Source	Same as Source
Cost Element	<> 5205	1102, 1502	5205	5205
AWO	*	Distribution Projects, <> Wildfire Mitigation, <> Labor Loading Only Projects	Same as Driver	2000013323

Distribution System - Operations Technology

	Source	Driver	Destination	Offset
Entity	PGE	PGE01	Same as Driver	PGE01
Unit	18100	18100	Same as Driver	18100
Account	1840023	1070001, Distribution Operations (58%), Distribution Maintenance (59%)	1070001, 5980001	1840023
Department	*	T&D Line and Substation Crews	Same as Source	Same as Source
Cost Element	<> 5205	1102, 1502	5205	5205
AWO	*	Distribution Projects, <> Wildfire Mitigation, <> Labor Loading Only Projects	Same as Driver	2000013323

Distribution Line

	Source	Driver	Destination	Offset
Entity	PGE	PGE01	Same as Driver	PGE01
Unit	18100	18100	Same as Driver	18100
Account	1840024	1070001, Distribution Operations (58%), Distribution Maintenance (59%)	Same as Driver	1840024
Department	*	T&D Line Crews	Same as Source	Same as Source
Cost Element	<> 5205	1102, 1502	5205	5205
AWO	*	Distribution Projects, <> Wildfire Mitigation, <> Labor Loading Only Projects	Same as Driver	2000013323

Distribution Substation

	Source	Driver	Destination	Offset
Entity	PGE	PGE01	Same as Driver	PGE01
Unit	18100	18100	Same as Driver	18100
Account	1840025	1070001, Distribution Operations (58%), Distribution Maintenance (59%)	Same as Driver	1840025
Department	*	T&D Substation Crews	Same as Source	Same as Source
Cost Element	<> 5205	1102, 1502	5205	5205
AWO	*	Distribution Projects, <> Wildfire Mitigation, <> Labor Loading Only Projects	Same as Driver	2000013323

Transmission Admin Overhead (TOSE)

Cost Element: 5215

Definition: The allocation includes the costs of the departments that directly support the daily activities of the line crews working on the Transmission network. For transparency, the allocation has been broken into six functions:

- **Transmission System**
  - General Supervision & Support
  - Engineering & Design
  - Load Dispatch
  - Operations Technology
- **Transmission Line**
  - Line Crew Supervision, Support & Misc. Operations
- **Transmission Substation**
  - Substation Crew Supervision, Support, Misc. Operations, etc.

Allocation Methodology: The costs incurred within the TOSE allocation pool(s) are allocated out based on where PGE's line crews and contract crews charged their straight time to transmission capital and O&M projects.

Allocation Criteria:

Transmission System - General Supervision & Support

	Source	Driver	Destination	Offset
Entity	PGE	PGE01	Same as Driver	PGE01
Unit	18100	18100	Same as Driver	18100
Account	1840026	1070001, Transmission Operations (56%), Transmission Maintenance (57%)	1070001, 5600013 (Operations), 5680013 (Maintenance)	1840026
Department	*	T&D Line and Substation Crews	Same as Source	Same as Source
Cost Element	<> 5215	1102, 1502	5215	5215
AWO	*	Transmission Projects, <> Wildfire Mitigation, <> Labor Loading Only Projects	Same as Driver	2000013324

Transmission System - Engineering & Design

	Source	Driver	Destination	Offset
Entity	PGE	PGE01	Same as Driver	PGE01
Unit	18100	18100	Same as Driver	18100
Account	1840027	1070001, Transmission Operations (56%), Transmission Maintenance (57%)	1070001, 5600014 (Operations), 5680014 (Maintenance)	1840027
Department	*	T&D Line and Substation Crews	Same as Source	Same as Source
Cost Element	<> 5215	1102, 1502	5215	5215
AWO	*	Transmission Projects, <> Wildfire Mitigation, <> Labor Loading Only Projects	Same as Driver	2000013324

Transmission System - Load Dispatch

	Source	Driver	Destination	Offset
Entity	PGE	PGE01	Same as Driver	PGE01
Unit	18100	18100	Same as Driver	18100
Account	1840028	1070001, Transmission Operations (56%), Transmission Maintenance (57%)	1070001, 5612001	1840028
Department	*	T&D Line and Substation Crews	Same as Source	Same as Source
Cost Element	<> 5215	1102, 1502	5215	5215
AWO	*	Transmission Projects, <> Wildfire Mitigation, <> Labor Loading Only Projects	Same as Driver	2000013324

Transmission System - Operations Technology

	Source	Driver	Destination	Offset
Entity	PGE	PGE01	Same as Driver	PGE01
Unit	18100	18100	Same as Driver	18100
Account	1840029	1070001, Transmission Operations (56%), Transmission Maintenance (57%)	1070001, 5692001	1840029
Department	*	T&D Line and Substation Crews	Same as Source	Same as Source
Cost Element	<> 5215	1102, 1502	5215	5215
AWO	*	Transmission Projects, <> Wildfire Mitigation, <> Labor Loading Only Projects	Same as Driver	2000013324

Transmission Line

	Source	Driver	Destination	Offset
Entity	PGE	PGE01	Same as Driver	PGE01
Unit	18100	18100	Same as Driver	18100
Account	1840030	1070001, Transmission Operations (56%), Transmission Maintenance (57%)	Same as Driver	1840030
Department	*	T&D Line Crews	Same as Source	Same as Source
Cost Element	<> 5215	1102, 1502	5215	5215
AWO	*	Transmission Projects, <> Wildfire Mitigation, <> Labor Loading Only Projects	Same as Driver	2000013324

Transmission Substation

	Source	Driver	Destination	Offset
Entity	PGE	PGE01	Same as Driver	PGE01
Unit	18100	18100	Same as Driver	18100
Account	1840031	1070001, Transmission Operations (56%), Transmission Maintenance (57%)	Same as Driver	1840031
Department	*	T&D Substation Crews	Same as Source	Same as Source
Cost Element	<> 5215	1102, 1502	5215	5215
AWO	*	Transmission Projects, <> Wildfire Mitigation, <> Labor Loading Only Projects	Same as Driver	2000013324

Other Administrative Overheads

Expendables

Cost Element: 5304 Line Expendables; 5305 Substation Expendables

Definition: The evaluation for designating items as Expendables/Tools includes the consideration of the following material characteristics: low unit cost, high usage, issuance unit is not equal to actual unit usage (rolls, tape, nails), high frequency of returns, sustained high rate of turns, consumable commonly reusable and predictable pattern of usage.

Allocation Methodology: The costs incurred within the Expendable allocation pools are allocated out based on where PGE's line/substation crews charged their time to T&D capital and O&M projects.

Allocation Criteria:

Line Expendables

	Source	Driver	Destination	Offset
Entity	PGE	PGE01	Same as Driver	PGE01
Unit	18100	*	Same as Driver	18100
Account	1840012	<> Expendable Source accounts, <> DOSE, <> TOSE, <> Service Providers, <> Suspense accounts, <> Customer Expense, <> A&G Expense	Same as Driver	1840012
Department	*	T&D Line Crews, Eagles	391	391
Cost Element	<> 5304	11*, 12*, 14*, 1501, 1601	5304	5304
AWO	*	Distribution Projects, Transmission Projects, <> Labor Loading Only Projects	Same as Driver	2000013325

Substation Expendables

	Source	Driver	Destination	Offset
Entity	PGE	PGE01	Same as Driver	PGE01
Unit	18100	*	Same as Driver	18100
Account	1840013	<> Expendable Source accounts, <> DOSE, <> TOSE, <> Service Providers, <> Suspense accounts, <> Customer Expense, <> A&G Expense	Same as Driver	1840013
Department	*	T&D Substation Crews	391	391
Cost Element	<> 5305	11*, 12*, 14*, 1501, 1601	5305	5305
AWO	*	Distribution Projects, Transmission Projects, <> Labor Loading Only Projects	Same as Driver	2000013326

Materials Overhead

Cost Element: 5302

Definition: The cost of labor and expenses incurred in operating Transmission and Distribution materials inventory storerooms.

Allocation Methodology: The allocation loads a fixed rate calculated during the budget cycle to all accounting strings which contain cost element 2101 - Storeroom Material Issue/Returns and 5304/5305 - Expendables. Throughout the year, material overhead balance is reviewed to make sure the balance is as expected and manual true-up will be made at year end if necessary. The true-up portion will be allocated dynamically under the same criteria of Material Overhead.

Allocation Criteria:

	Source	Driver	Destination	Offset
Entity	N/A	PGE01	Same as Driver	PGE01
Unit	N/A	18100	Same as Driver	18100
Account	N/A	<> Expendable Source accounts, <> DOSE, <> TOSE, <> Service Providers, <> Suspense accounts, <> Customer Expense, <> A&G Expense	Same as Driver	1630001
Department	N/A	*	617	617
Cost Element	N/A	2101, 5304 ,5305	5302	5302
AWO	N/A	Distribution Projects, Transmission Projects, <> Labor Loading Only Projects	Same as Driver	2000013327

* See Appendix A for fixed allocation percentage that is applied to accounts noted in the driver.

Other Allocations

PGE Share

Cost Element: 7001

GL Journal Category: PGE_SHARE

Definition: To allocate PGE's share of capital and operational costs of co-owned plants according to co-ownership agreement. The co-owned plants include KB Pipeline, Coyote Springs, Trojan, Boardman, Pelton Project, and Round Butte.

Allocation Criteria:

OU	Plant Name	PGE's Share	Co-owner's Share
82100	KB Pipeline	79.50%	20.50%
86100	Coyote Springs	50.00%	50%
91100	Trojan	67.50%	32.50%
92100	Boardman	90.00%	10%
96100	Pelton Project	50.01%	49.99%
99100	Round Butte Project	50.01%	49.99%
99600	Round Butte Switchyard	64.01%	36%

Plant

Cost Element: 7002

GL Journal Category: PLANT

Definition: To charge the monthly plant activities booked in JPL63 to Co-owners. The co-owned plants include KB Pipeline, Coyote Springs, Trojan, Boardman, Pelton Project and Round Butte.

Dividend Close

Cost Element: 5498

GL Journal Category: DIVIDEND_CLOSE

Definition: To reclass the monthly retained earning balance in 4380001 and 4390001 to 2161003- undistributed earnings.

Appendix A

2024 WTC Cost Allocation Spread

	Accounting String	Fixed %
Corporate A&G	PGE01-18100-9200001	68%
Non-Utility Space	PGE01-18100-4171008	32%

2024 Helicopter Allocation Rates

	Accounting String	Fixed %
Transmission 500kv	PGE01-18100-5710001	25.5%
Transmission 230kv	PGE01-18100-5710002	31.6%
Transmission 115kv	PGE01-18100-5710004	16.8%
Distribution 57kv	PGE01-18100-5930001	0%
Wildlife (East)	PGE01-99100-5370002	20.9%
Wildlife (West)	PGE01-15200-5370002	5.2%

2024 Material Overhead Rate

Fixed %
16%

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PORTLAND GENERAL ELECTRIC
COST ALLOCATION ACTUALS
FOR THE YEAR 2024

Following is a table which includes the actual labor loading rates for 2024:

Labor Loading Rates	2024 Actual Rates	2024 Actual Costs
Payroll Taxes	10.70%	35,322,893.39
Employee Benefits	31.74%	89,487,928.05
Corporate Incentives	7.78%	15,980,371.58
Injuries & Damages	8.34%	23,242,969.41
Vacation (PTO)	17.18%	48,563,507.33
Pension Service Cost *	3.36%	3,525,424.68
Net Periodic Pension Cost *	-2.11%	
Other Post-Retirement Benefits	0.46%	1,304,504.65
2024 Actual Total		217,427,599.09

*Note: Since the pension related loadings share components of pension expense, total pension expense is shown for both loadings in order to calculate total allocable costs.

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PORTLAND GENERAL ELECTRIC
COST ALLOCATION ACTUALS
FOR THE YEAR 2024

Operating costs which are identifiable to specific utility or non-utility operations are directly allocated.

WTC Cost Distribution (Actual)		
PGE (Utility/Non-Utility Tenants)		66%
Non-PGE Tenants		34%
Total Cost Pool	$	12,353,200
PGE's Share Allocated	$	8,213,942

Below is a table of the actual distribution percentages of the 2024 WTC costs allocated to PGE:

World Trade Center Allocation	**% Lease Cost**
Utility Capital	0.04%
Trojan	1.86%
Utility Expense	1.94%
Non-Utility	96.16%
2024 Actual Total	**100.00%**

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PORTLAND GENERAL ELECTRIC
COST ALLOCATION ACTUALS
FOR THE YEAR 2024

Included below is a table which lists the 2024 actual percentages and costs for the Service Provider Allocations:

	Information Technology	**Helicopter**
Trojan	1.26%	N/A
Coyote Springs	1.79%	N/A
Pelton/Round Butte	2.64%	21.17%
Generation	17.33%	5.27%
Transmission	0.68%	73.57%
Distribution	8.73%	N/A
Customer Service	12.36%	N/A
Admin & General	15.60%	N/A
Utility	38.77%	N/A
Non-Utility	0.48%	N/A
Affiliates	0.36%	N/A
Totals	**100.00%**	**100.00%**
2024 Actual Total	$ 87,052,913	$ 631,168

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PORTLAND GENERAL ELECTRIC
COST ALLOCATION ACTUALS
FOR THE YEAR 2024

Fleet Services

Actual costs associated with operation and maintaining the company vehicle fleet for 2024 total $22,335,578.60

PGE General Inventory

The 2024 Stores loading (also referred to as the materials loading) rate is as follows:

16%

PORTLAND GENERAL ELECTRIC
COST ALLOCATION ACTUALS
FOR THE YEAR 2024

Included below is a table which shows the 2024 actual percentages and costs for the Corporate Governance Allocation:

Corporate Governance

Trojan	0.91%
Coyote Springs	1.25%
Pelton	0.99%
Round Butte	1.30%
KB Pipeline	0.04%
Generation	0.00%
Transmission	0.01%
Distribution	0.00%
Customer Service	0.00%
Admin & General	49.58%
Utility	45.13%
Non-Utility	0.44%
Affiliates	0.35%
	100.00%
2024 Actual Total	$ 23,788,572.07

Capital Accounting Policy

Portland General Electric

Last Revision Date: May 18, 2022

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Introduction

Purpose

This policy provides company guidelines for classifying expenditures as capital for Portland General Electric (PGE). Accounting for capitalization expenditures must use a consistent methodology following generally accepted accounting principles (GAAP), federal requirements, and regulatory reporting.

The Federal Energy Regulatory Commission (FERC) Electric Plant Instructions in CFR 18 Part 101, Uniform System of Accounts is the primary guideline used by PGE for identifying capital expenditures and major units and minor items of property.

Revisions

The capitalization policy of the Company is established by the Chief Financial Officer (CFO) and Controller. A formal review will occur at least annually, and significant updates will be published as soon as practicable. The Controller will implement and administer the corporate capitalization policy in accordance with GAAP and FERC.

Acronyms

The following table defines some key acronyms used throughout this document:

Acronym	Definition
AFUDC	Allowance for funds used during construction
ASC	Accounting Standards Codification
AWO	Accounting work order
CFR	Code of Federal Regulations
CWIP	Construction work-in-progress
FERC	Federal Energy Regulatory Commission
GAAP	Accounting principles generally accepted in the United States of America
OPUC	Public Utility Commission of Oregon
ORS	Oregon Revised Statute
PP&E	Property, Plant and Equipment
RWIP	Retirement Work in Progress
SEC	United States Securities and Exchange Commission
T&D	Transmission & Distribution

Capitalization Policy

General Guidance

PGE follows GAAP and FERC guidelines to determine when expenditures should be classified as capital and considered additions or retirements of Property, Plant, and Equipment (PP&E). Authoritative guidance includes:

- GAAP Guidance – Accounting Standards Codification (ASC) 360 – Property, Plant and Equipment
- FERC Guidance – Code of Federal Regulations (CFR) Title 18, Chapter 1, Electric Plant Instructions

Capitalization Criteria

In general, expenditures will be capitalized and depreciated if they meet the following criteria:

- Have an economic useful life more than one year
- Can be reasonably and cost effectively identified and accounted for
- Results in the creation of a new fixed asset (Retirement Unit)
- Replaces an existing fixed asset (Retirement Unit)
- Capitalizing is consistent with engineering construction techniques and field practices
- Capitalizing is consistent with FERC and GAAP
- Results in the betterment or modification of an existing fixed asset which satisfies either of the following:
    - Significantly extends the useful life of the asset beyond the originally anticipated life period
    - Significantly alters the use of the asset

Electric Utility Plant – Capitalization Policy

Electric utility plant is capitalized at original cost, which includes direct labor, materials and supplies, and contractor costs, as well as indirect costs such as engineering, supervision, employee benefits, and an allowance for funds used during construction (AFUDC). Plant replacements are capitalized, with minor items charged to expense as incurred. Costs to purchase or develop software applications for internal use only are capitalized and amortized over the estimated useful life of the software. Costs of obtaining FERC licenses for the Company's hydroelectric projects are capitalized and amortized over the related license period.

During the period of construction, costs expected to be included in the final value of the constructed asset and depreciated once the asset is complete and placed in service, are classified as Construction work-in-progress (CWIP) in Electric utility plant on the consolidated balance sheets. If the project becomes probable of being abandoned, such costs are expensed in the period such determination is made. If any costs are expensed, PGE may seek recovery of such costs in customer prices, although there can be no guarantee such recovery would be granted. Costs disallowed for recovery in customer prices, if any, are charged to expense at the time such disallowance becomes probable.

PGE records AFUDC, which is intended to represent the Company's cost of funds used for construction purposes, based on the rate granted in the latest general rate case for equity funds and the cost of actual borrowing for debt funds. AFUDC is capitalized as part of the cost of plant and credited to the consolidated statements of income.

Capital Accounting Policy Interpretations

The Capital Accounting Policy Interpretations document contains specific capital policy interpretations and guidance. The document will be updated on a frequent basis as new guidance and interpretations arise.

Retirement Units (Units of Property)

A retirement unit is the smallest item of property which when replaced or removed from service must be retired from the electric plant accounts. It is always capitalized when originally installed and its replacement is always capitalized. Retirement units are generally costly and long lived. A retirement unit may also be referred to as a property unit or units of property. A property unit is either and individual retirement unit or a combination of retirement units.

Retirement units are a representation of PGE's capitalization policy. When retirement units no longer reflect current capitalization policy, a revision to the units should be made. Changes in technology or construction field practices are the primary reasons which support a retirement unit revision.

Asset Accounting is responsible for maintaining the Retirement Unit Catalog. A high-level internal review should be performed annually to support company compliance for capitalization. By performing reviews annually, the retirement unit lists will stay current, support the understanding of the company capitalization policies, improve and maintain an understanding of the purpose of retirement units, and reduce the impact that longer periods between reviews create to the overall capital policy in place.

Minor Item of Property

Minor items of property are all items that are part of a related retirement unit and are generally inexpensive. The cost to add or remove an existing minor item of property shall be expensed to the appropriate maintenance account.

Betterment

Betterment represents an improvement or enlargement of existing depreciable electric plant property by the replacement of minor items of property independent of the retirement units of which they are part. It should only be considered as a reason for capitalization when there is no retirement unit being installed by the project.

Betterment permits capitalization of the difference between the current material costs of the betterment part over the current material costs of the replaced parts. No labor or other costs can be capitalized using these criteria.

Betterment should only be used as a reason for capitalization when there is an improvement or enlargement of existing depreciable electric plant where the improvement has the effect of significantly extending the original life or increasing the capacity or lowering the operating cost of the retirement unit affected. Betterment will only be considered when a substantial addition of $100,000 or greater results.

FERC Chart of Accounts

The FERC has prescribed a Uniform System of Accounts for utilities to use. The following table provides an overview of the account structure:

	Account Group	Range	Type of Account
1	Assets and Other Debits	101-120 121-129 130-176 181-190	Utility Plant Other Property and Investments Current and Accrued Assets Deferred Debits
2	Liabilities and Other Credits	201-219 221-226 227-230 231-245 251-283	Proprietary Capital Long-Term Debt Other Noncurrent Liabilities Current and Accrued Liabilities Deferred Credits
3	Electric Plant		
	Intangible Plant	301-303	Intangible Plant
	Production Plant	310-317 320-326 330-337 340-348	Steam Production Nuclear Production Hydraulic Production Other Production
	Transmission Plant	350-359.1	Transmission Plant
	Distribution Plant	360-374	Distribution Plant
	Regional Transmission & Market Operation	380-387	Regional Transmission & Market Operation Plant
	General Plant	389-399.1	General Plant
4	Income *Includes Non-Utility Income & Expenses	400-414 415-421.1 421.2-426.5 408.2-420 427-432 434-435	Utility Operating Income Other Income Other Income Deductions Taxes Applicable to Other Income and Deductions Interest Charges Extraordinary Items
5,9	Operation and Maintenance Expense		
	Power Production Expense	500-509 510-515	Steam Power Generation – Operation Expense Steam Power Generation – Maintenance Expense
	Nuclear Power Generation Expense	517-525 528-532	Nuclear Power Generation – Operation Expense Nuclear Power Generation – Maintenance Expense
	Hydraulic Power Generation Expense	535-540.1 541-545.1	Hydro Power Generation – Operation Expense Hydro Power Generation – Maintenance Expense
	Other Power Generation Expense	546-550.1 551-554.1	Other Power Generation – Operation Expense Other Power Generation – Maintenance Expense
	Other Power Supply Expense	555-557	Other Power Supply Expenses
	Transmission Expense	560-567.1 568-574	Transmission – Operation Expense Transmission – Maintenance Expense
	Regional Market Expense	575.1-575.8 576.1-576.5	Regional Market – Operation Expense Regional Market – Maintenance Expense
	Distribution Expense	580-589 590-598	Distribution – Operation Expense Distribution – Maintenance Expense
	Customer Accounts Expense	901-905	Customer Accounts – Operation Expense
	Customer Service & Informational Expense	906-910	Customer Service – Operation Expense
	Sales Expense	911-917	Sales – Operation Expense
	Administrative & General Expense	920-933 935	Administrative & General – Operation Expense Administrative & General – Maintenance Expense

Construction Activity

Forecasting of In-Service Dates

Projects managers are responsible for updating the forecasted in-service dates of their projects within PowerPlan. It is important that these dates are regularly updated to ensure that AFUDC is only accrued on projects still under construction and projects are placed in service in a timely manner.

Cost of Removal (COR) and Salvage

Cost of Removal (COR) is the cost of demolishing, dismantling, tearing down or otherwise removing electric plant, including the cost of transportation and handling. Any COR expenditures and proceeds from salvage are to be recorded to account 1080001.

Contributions in Aid of Construction (CIAC)

PGE may receive funding from a customer for a portion of the costs of construction, which offsets the overall capital cost. The amount of CIAC to be received is reflected as a reduction to capital costs. CIAC rates are calculated based on a specific tariff rate approved by the OPUC for the share that a customer agrees to pay.

CIAC received should be recorded to account 1070001 using cost element 6001.

Construction Overheads

Construction overheads are support costs for construction that are not directly assigned to specific construction projects. Support activities relate to the planning, designing, engineering, supervision, administration and constructing and completing of construction projects. Overheads are incurred for activities that charge to construction but are not practical or cost-effective to charge directly to the projects. As a result, the projects bear an equitable share of overheads as prescribed by FERC.

The following are the primary construction overheads:

Plan Analyze and Design (PAD)

The directly incurred engineering and all associated expenses for T&D capital construction projects. These costs – whether incurred by PGE engineers or by contracted engineers are directly and specifically applicable to constructed assets.

Distribution Operations, Supervision & Engineering (DOSE)

Includes costs associated with system planning, engineering, design, system mapping, scheduling, coordinate new customer connects, dispatch crews, system control to ensure continued service during construction, safety inspections, system testing, system reliability, substation engineering, process work orders, dispatch for repair, damage claims, inspection of customers facilities for construction, and permitting. Although this is not an all-inclusive list of every work activity, it demonstrates the high volume of different types of work activities and the difficulties that would arise in trying to capture these costs by direct charging to individual work orders.

A capitalization percentage/rate is developed each month based on the amount of actual capital/O&M work that has been performed on a year-to-date basis. This capitalization rate is applied to the overall DOSE charges at month end, with those charges reclassified to capital.

PSES Administrative Overhead Allocation

Similar concept to DOSE, except for Generation projects. The charges accumulate within a generation cost pool. Throughout the month direct labor charging occurs to both capital and O&M projects which derives an allocation percentage.

Allowance for Funds Used During Construction (AFUDC)

Definition

AFUDC includes the net cost for the period of construction of borrowed funds used for construction purposes (debt) and a reasonable rate of return on other funds when used (equity). The cost of debt and equity funds used during construction is a component of the cost to construct facilities for the production, transmission, distribution, and delivery of electric service, and is capitalized monthly in CWIP to account 1070001.

Exceptions – AWOs Not Eligible for AFUDC

The following AWOs are not eligible to receive AFUDC:

- Jobs that purchase equipment only (vehicles, tools, computers, furniture, etc.)
- Work orders that close monthly, such as customer blanket jobs
- Removal work orders
- Customer funded projects where the customer pays 100% of the construction
- Non-utility work orders
- Operations and Maintenance (O&M) work orders

Work orders that have had no capital activity for three consecutive months will be evaluated to determine if AFUDC should still be accrued.

Rate and Methodology

The AFUDC rate is calculated using the FERC-prescribed formula, with the exceptions PGE requested and FERC approved in 1982. The exceptions are:

- Utilizing monthly balances and applicable cost levels as of the end of the preceding month for all components of capital
- Utilizing CWIP balances and short-term debt cost rates and balances in the month that the AFUDC rate is to be used
- Example: In determining the monthly AFUDC rate, the September 2020 calculation would use:
- August 2020 balances and rates for equity and long-term debt
- September 2020 balances and rates for CWIP and short-term debt

The AFDUC rate applied to CWIP is a gross rate as deferred income taxes for AFUDC are recorded separately.

Computation

For each AWO, AFUDC is computed by applying the calculated rate to the beginning monthly balance and on one-half of the current month's capital charges. For purposes of the AFUDC computation, accruals are not included. In the month a project closes, the rate is applied to one-half of both the beginning monthly balance and to the current month's capital charges. The only exception is for major projects greater than $100 million in gross plant that are placed into service and customer prices either immediately or the revenue requirement is deferred for future collection. For these projects, in the month the project closes the calculated AFUDC rate is applied to the beginning monthly balance for the number of days the project remained in CWIP for the current month plus one-half of the current month charges. AFUDC is compounded no more than semiannually (currently in January and July).

Tax Construction Period Interest (CPI)

Internal Revenue Code (IRC) §263A(f) requires the capitalization of interest costs which are paid during the production period of four types of property:

1. Real property; or

2. Tangible personal property that has a tax class life of 20 years or more under IRC §168,

3. Tangible personal property with an **estimated** production period exceeding two years, or

4. Tangible personal property with an **estimated** production period exceeding one year and an **estimated** cost exceeding $1 million.

Preliminary Survey

The FERC prescribes through the CFR that utilities may use balance sheet account 183 for such costs that are incurred while performing preliminary survey work, planning activities, investigations, etc., for the purpose of determining the feasibility of a utility project under consideration. This account classification does not allow for recovery of costs from PGE customers until such costs are reclassified to capital and the construction project is used and useful. It also does not accrue AFUDC while classified to this account.

There are two definitions in use for engineering and related work activity – detailed engineering and preliminary engineering for this purpose.

- Detailed Engineering – represents design activities (design engineering) that are incurred prior to the contracting, scheduling and ultimate construction of a Capital project defined with a specific scope and outcome written into an approved Funding Project. It is not necessary for a project to have initially incurred work through Preliminary Survey to move to Detailed Engineering. These activities are generally incurred as capitalized accounting.

- Preliminary Survey (Engineering) – represents analysis activities, creating or obtaining survey data, plans and investigation work, which are incurred to determine the feasibility or differing options of a project under contemplation. From this work, engineering should be able to begin proposing plans as required under corporate policy for evaluation and approval/non-approval as determined for a capital project.

Consideration of recording expenditures as preliminary survey should be given when:

- The engineering and other development activities occur over an extended period before approval for moving forward to contracting and construction occurs.

- The Company is in the process of determining feasibility and path of construction that may result in capitalized construction project.

During the period the costs are recorded in this account, a quarterly assessment is made to address the probability that such amounts will ultimately support a capital project.

If the project is approved, preliminary survey costs associated with the resulting defined project scope are reclassified to capital. Costs not associated with the resulting defined project scope and any work that is abandoned are to be expensed to account 426.5 - Other Deductions.

Charges that are eligible include costs that meet capitalization criteria including:

- Direct PGE labor costs where employees are providing significant time and services to directly support these projects

- External costs incurred to directly support these projects such as contract labor, external consultants, business expenses, fees, and legal costs

Software

Effective May 2022, the accounting policy for software has been moved to a separate policy document. Refer to the Internal Use Software Accounting Policy.

Plant-in-Service

The following section describes the definition and process for placing assets in service.

Used and Useful

PGE classifies capitalized construction costs as Closed to Plant when the project and associated capitalized costs can be determined to be used and useful for utility services. Used and useful means the completion of the installation, modification, or construction of the elements essential to the project and that they are ready for their intended use or assigned function. Once an asset becomes used and useful, the useful life and depreciation group of the asset are also identified.

Basic Criteria for Determination of Asset in Service

- Asset is ready for a specific use in an income-producing activity even if the asset is not being used.
- Useful life and timing of when the depreciation begins and ends are clearly identified.

Some factors to consider when deciding on whether a project is complete, and the asset is used and useful:

- Transmission/Distribution - can the asset/equipment be energized?
- Generation facility
  - Major, critical construction work is completed
  - Critical pre-operational testing has been completed
  - The unit can operate at or near its designated capacity for sustained periods and is available for regular operations
  - Energy has synchronized to the grid
- Software/Application/Website
  - Can the product perform the function that was agreed upon during the requirement analysis phase?
- Computers, Furniture, Vehicles, Tools, Lab Equipment, Spare Equipment
  - These asset costs are closed in the same month of their purchase. It is expected that these products are useful to the company at the time of purchase, and not for inventory.
- Line Transformers, Customer Meters
  - These asset costs are closed in the same month of purchase.
  - The Code of Federal Regulations # 18 (CFR) states that capital FERC accounts 368 (transformer) and 370 (meter) will include the cost of these items, whether they are in service or held in reserve.

Placing Assets in Service

When a project is "Substantially Complete", the project will be identified as in-service. Substantial completion means the completion of the installation, modification, or construction of the elements essential to the project and that they are ready for their intended use or assigned function. The Project Manager is responsible for entering the in-service date in the PowerPlan system. This identification allows for accounting to reclassify the capitalized costs from CWIP to Plant-In-Service.

Trailing Charges

When a project is placed in service, it is expected that there may be appropriate capital trailing costs necessary to complete a project. The trailing period is currently set to a maximum of eight months after the project is placed in service. Software projects should only have trailing charges for a period of 1-2 months after go-live. Any charges after the trailing charge period should be expensed or discussed with Asset Accounting.

It may be necessary to create a new AWO for these trailing costs. Asset Accounting will apply company capitalization policy to determine whether trailing costs are capital or expense.

Depreciation and Amortization

Definition

The original cost of a capital asset, including a provision for estimated net salvage, is depreciated on a straight-line basis over its estimated economic useful life.

Group Depreciation

Group depreciation theory is the assumption that the appropriate life for a group of assets is an average of all the individual lives within the group. The dispersion of retirements on that average service life is defined for most utilities by an Iowa-type survivor curve.

For all plant, the straight-line, remaining life, unit-summation depreciation method is used. Under this method, depreciation is determined by applying a depreciation rate (1.0 divided by the average remaining life) to the group's net book value. Any reserve excesses/deficiencies are automatically depreciated over the remaining average lives of the asset groups.

The objective of the unit-summation procedure is to fully recover the cost of each asset during its useful life. Iowa-type survivor curves are used to estimate annual retirements. Each group, in effect, is depreciated separately.

Amortization

Certain general plant accounts are amortized rather than depreciated for administrative ease. Records for these assets are condensed into single retirement units within each asset group. The entire vintage is retired upon reaching an authorized depreciation life. The amortization rate (1.0/average remaining book life) is applied to the original book cost, plus or minus estimated salvage, less accumulated depreciation.

Items that are amortized include software and intangible hydro relicensing assets. Hydro relicensing assets are amortized over the life of the hydro license period, and generation related intangibles (other than software) are amortized over the life of the related generating plant.

Non-Depreciable Assets

Land is not a depreciable asset.

Depreciation Study Requirements

A depreciation study is required to be filed every five years with the OPUC. Studies may be filed more frequently at PGE's discretion. Changes to depreciation parameters (e.g. retirement dispersion patterns, methods, procedures, average service lives and net salvage rates) require OPUC approval and are implemented with changes in approved rates.

Plant Dispositions

Asset Retirement Obligations (ARO)

Definition

An Asset Retirement Obligation (ARO) is a legal obligation resulting from the acquisition, construction, or development and (or) the normal operation of a long-lived asset that compels a company to remove the long-lived asset and (or) to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. A legal obligation can arise from Federal, state, or local government laws, ordinances, licenses, permits, site certificates or zoning variances, public statements of a company official, or written or oral promises to a third-party (promissory estoppel).

Policy

The fair value of a liability for an ARO is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. If a reasonable estimate of fair value cannot be made in the period the asset retirement obligation is incurred, the liability is recognized when a reasonable estimate of fair value can be made. If the fair value of an ARO cannot be reasonably estimated, that fact and the reasons are disclosed.

Regulation

Costs of removal related to the retirement of PGE's regulated long-lived assets have historically been included in depreciation expense allowed in PGE's rates charged to customers. PGE expects any changes in estimated AROs to be incorporated in future rates. Substantially all significant AROs are included in rate regulation. Timing differences between cost of removal recognized for book purposes versus regulation purposes are recorded as regulatory assets and/or regulatory liabilities.

Initial Recognition

Upon initial recognition of ARO's that are measurable, the probability weighted future cash flows for the associated retirement costs, discounted at a credit-adjusted risk-free rate, is recognized as both an ARO liability and as an increase in the capitalized carrying amount of the related long-lived assets (ARC asset). In addition, total-to-date accrued accretion expense is reclassified from Accumulated Depreciation to the ARO liability.

The initial measurement of an ARO is fair value. Because of the long lead time involved until future decommissioning activities occur, quoted market prices and a market-risk premium are not available so PGE estimates cash flows that reflect the cost and timing of internally performing the required retirement activities plus a contingency factor, approximating the amount a third party would demand to take on the risks of the future removal costs.

Ongoing Procedures

PGE's ARO analyses of its long-lived assets are reviewed to ensure all applicable ARO's have been identified and are listed and (or) quantified in the financial statements. Major differences in the expected timing of removal cost activity or the estimated scope of decommissioning

activities are taken into consideration by adding new layers of ARO's. Revisions in the timing or the amount of estimated cash flows are to be recognized as changes in the carrying amount of the liability and the related capital asset and are to be measured using the current credit-adjusted risk-free rate for upward revisions, or using the credit-adjusted risk-free rate applied in the initial measurement for downward revisions.

Capitalized asset retirement costs are depreciated over the life of the related asset. Accretion of the ARO liability is classified as an operating expense. The ARO liability is relieved as removal costs are expended.

Property Sales

Policy

Oregon Revised Statute (ORS) 757.480 requires OPUC approval prior to selling, leasing, donating or otherwise disposing of assets with a value greater than $1,000,000. For sales of utility property with values between $25,000 and $1,000,000, the Company is required to notify the OPUC annually of those sales.

The Company has an obligation to ensure that all asset sales serve the public interest, which means that the assets are not necessary for the Company to provide service to the public. Utility equipment will be priced at market value. If a market value cannot be established, the asset should be priced at current replacement cost less depreciation.

Billing Customers for Plant or Equipment

If PGE intends to bill a customer for plant or equipment (such as poles, full span of conductor, pole to pole, vault to vault, switches, etc.) removed from service, a Depreciation worksheet is used to determine the cost that the customer is responsible for. The Depreciation worksheet is used to determine the remaining value and removal costs for these assets. Relocation, transfer, and modification costs are billed at current costs.

Basis for Installation

When removing (retiring) PGE facilities, the first step is to determine the basis for the installation. The basis for the installation is the dollar amount on PGE's books for the facilities. Typically, this is the fully loaded installation costs minus any customer contributions. A review of the original job installation of the facilities is performed to determine the original cost. If the original job is not available, the assumption is that the customer made no contributions.

If only a portion of the original project is being removed, the current cost of the or equipment needs to be estimated. The current cost is then trended back to the original vintage year of installation to determine the current net book value, which represents the replacement cost of the asset. The replacement costs are added to labor costs to remove to determine the amounts to bill the customer.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Portland General Electric Company

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Portland General Electric Company and subsidiaries (the "Company") as of December 31, 2024 and 2023, the related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows, for each of the three years in the period ended December 31, 2024, and the related notes (collectively referred to as the "financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2024, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2024 and 2023, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2024, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2024, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

Basis for Opinions

The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the financial statements included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail,

accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current-period audit of the financial statements that were communicated or required to be communicated to the audit committee and that (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Regulatory Accounting — Refer to Notes 2 and 7 to the consolidated financial statements

Critical Audit Matter Description

The Company is subject to rate regulation by the Public Utility Commission of Oregon (the "OPUC"), which has jurisdiction with respect to the rates for retail electricity in the state of Oregon, and to wholesale rate regulation by the Federal Energy Regulatory Commission (the "FERC"). Management has determined it meets the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Accounting for the economics of rate regulation impacts certain financial statement line items and disclosures.

The Company's rates are subject to regulatory rate-setting processes and annual earnings oversight. Because the OPUC and the FERC set the rates the Company is allowed to charge customers based on allowable costs, including a reasonable return on equity, the Company applies accounting standards that require the financial statements to reflect the effects of rate regulation. The Company's rates for retail customers are determined and approved in regulatory proceedings based on an analysis of the Company's cost of providing service to retail customers. The OPUC has the authority to disallow the recovery of any costs that it considers imprudently incurred. Although the OPUC is required to establish customer prices that are fair, just and reasonable, it has significant discretion in the interpretation of this standard. The Company assesses whether the regulatory assets and regulatory liabilities continue to meet the criteria for probable future recovery or settlement at each balance sheet date and when regulatory events occur. This assessment includes consideration of recent rate orders, historical regulatory treatment for similar costs, and factors such as changes in applicable regulatory and political environments. While the Company has indicated it expects to recover costs from customers through regulated rates, there is a risk that the OPUC and the FERC will not approve: (1) full recovery of the costs of providing utility service, or (2) full recovery of amounts invested in the utility business and a reasonable return on that investment.

We identified the impact of rate regulation as a critical audit matter due to its pervasive impact on the Company's financial statements and the significant judgments made by management to support its assertions about certain account balances and disclosures. Given that management's accounting judgments are based on assumptions about the outcome of future decisions by the OPUC or FERC, including decisions regarding the prudency of costs which have been deferred as regulatory assets, auditing these judgments required specialized knowledge of accounting for

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 459

Application for Distribution System Plan Alternative Rate Mechanism

PORTLAND GENERAL ELECTRIC

Direct Testimony
Pricing

Chris Pleasant, PGE

July 25, 2025

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I. Introduction

Q. Please state your name and position with Portland General Electric Company (PGE).

A. My name is Chris Pleasant. I am a Regulatory Consultant in the Pricing and Tariff Department. My qualifications are included at the end of this testimony.

Q. What is the purpose of your testimony?

A. My testimony describes the following:

- PGE's proposed new tariff Schedule 121.
- The estimated rate impacts from this filing anticipated to be effective on April 1, 2026.
- The calculation and allocation of Schedule 121 prices.

Q. How does PGE propose collecting the costs associated with the Distribution System Plan Alternative Recovery Mechanism (DSP ARM)?

A. PGE is proposing a new limited-single use supplemental tariff, Schedule 121 Distribution System Plan Alternative Recovery Mechanism (DSP ARM), shown in PGE Exhibit 401. This tariff will allow PGE to collect the revenue requirement associated with PGE's DSP ARM, until these costs and benefits can be included in base rates in a future general rate review. Once these costs are included in base rates, PGE will retire the limited-single use DSP ARM tariff.

Q. Why is PGE proposing a new supplemental tariff rather than including the costs associated with the DSP ARM in an existing supplemental tariff?

A. Given that PGE does not currently have an existing supplemental schedule that meets the needs of including the DSP ARM into customer prices between rate proceedings, PGE proposes to use Schedule 121 exclusively for the DSP ARM costs and benefits until they are

included in base rates. When the costs and benefits are included in base rates, PGE will retire the Schedule 121 tariff.

Q. What are the rate impacts of the proposed $72.2 million increase in Schedule 121 prices?

A. Table 1, below, summarizes the estimated April 1, 2026, Cost of Service (COS) rate impacts for selected rate schedules.

Table 1
Estimated Rate Impacts

Schedule	Rate Impact
Sch 7 Residential	2.8 %
Sch 32 Small Non-residential 30 kW or less	2.7 %
Sch 83 Non-residential 31-200 kW	2.2 %
Sch 85 Secondary 201-4,000 kW	1.3 %
Sch 85 Primary 201-4,000 kW	1.3 %
Sch 89 Primary Over 4,000 kW	1.2 %
Sch 89 Subtransmission Over 4,000 kW	1.7%
Schedule 90	0.8%
COS Overall	2.2 %

Q. Please describe how you allocate the Schedule 121 amount to each rate schedule and how you calculate the Schedule 121 price.

A. PGE allocates Schedule 121 to COS and Direct Access customers, using the applicable schedule's forecasted energy on the basis of an equal percent of distribution revenue applied on a cents per kWh basis to each applicable rate schedule.

II. Qualifications

Q. Mr. Pleasant, please state your educational background and qualifications.

A. I received a Bachelor of Arts degree in Art History from the University of Oregon. I have been employed at PGE since 2001, working in various departments including Customer Billing, Automated Metering Infrastructure, Information Technology and Transmission Settlements. I have worked in the Rates and Regulatory Affairs department since January 2020.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
401	Schedule 121 Distribution System Plan Alternative Recovery Mechanism

Portland General Electric Company
P.U.C. Oregon No. E-19 **Original Sheet No. 121-1**

SCHEDULE 121
DISTRIBUTION SYSTEM PLAN ALTERNATIVE RECOVERY MECHANISM

PURPOSE

This Schedule recovers the revenue requirement associated with PGE's Distribution System Plan.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service except Schedules 76R, and 576R.

ADJUSTMENT RATE

The Adjustment Rate, applicable for service on and after the effective date of this schedule are:

Schedule	Adjustment Rate	
7	0.564	¢ per kWh
15/515	0.597	¢ per kWh
32/532	0.524	¢ per kWh
38/538	0.691	¢ per kWh
47	0.910	¢ per kWh
49/549	0.876	¢ per kWh
75/575		
Secondary	0.062	¢ per kWh
Primary	0.062	¢ per kWh
Subtransmission	0.044	¢ per kWh
83/583	0.330	¢ per kWh
85/485/585		
Secondary	0.145	¢ per kWh
Primary	0.110	¢ per kWh

Portland General Electric Company
P.U.C. Oregon No. E-19 **Original Sheet No. 121-2**

SCHEDULE 121 (Concluded)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate	
89/489/589/689		
Secondary	0.062	¢ per kWh
Primary	0.062	¢ per kWh
Subtransmission	0.044	¢ per kWh
90/490/590		
Primary 30-250 MWa	0.064	¢ per kWh
Primary >250 MWa	0.057	¢ per kWh
Subtransmission	0.064	¢ per kWh
91/491/591	0.600	¢ per kWh
92/492/592	0.167	¢ per kWh
95/495/595	0.600	¢ per kWh

SPECIAL CONDITIONS

1. Costs recovered through this schedule will be allocated to each schedule using the applicable schedule's forecasted energy on the basis of an equal percent of distribution revenue applied on a cents per kWh basis to each applicable rate schedule.

2. The costs for projects included under this schedule will be updated annually as provided above and will continue to be recovered under Schedule 121 until such time as the costs are included in base rates.

3. Once the Distribution System Plan is included in base rates or is no longer in service, this Schedule will be withdrawn, and no other assets will be placed within this Schedule.

Oregon Public Utility Commission

e-FILING REPORT COVER SHEET

COMPANY NAME: NW Natural

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☐ No ☐ Yes If yes, submit a redacted public version (or a cover letter) by email. Submit the confidential information as directed in OAR 860-001-0070 or the terms of an applicable protective order.

Select report type: ☐ RE (Electric) ☐ RG (Gas) ☐ RW (Water) ☐ RT (Telecommunications)
☐ RO (Other, for example, industry safety information)

Did you previously file a similar report? ☐ No ☐ Yes, report docket number: RO 16

Report is required by: ■ OAR 860-021-0408
☐ Statute
☐ Order
Note: A one-time submission required by an order is a compliance filing and not a report (file compliance in the applicable docket)
☐ Other
(For example, federal regulations, or requested by Staff)

Is this report associated with a specific docket/case? ☐ No ☐ Yes, docket number: RO 16

List Key Words for this report. We use these to improve search results.

Energy Burden

Send the completed Cover Sheet and the Report in an email addressed to PUC.FilingCenter@state.or.us

Send confidential information, voluminous reports, or energy utility Results of Operations Reports to PUC Filing Center, PO Box 1088, Salem, OR 97308-1088 or by delivery service to 201 High Street SE Suite 100, Salem, OR 97301.

NW Natural®

250 SW Taylor Street
Portland, OR 97204

503-226-4211
nwnatural.com

January 29, 2026

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
Post Office Box 1088
Salem, OR 97308-1088

Re: RO 16 – Energy Burden Metrics Report OAR 860-021-0408

In compliance with OAR 860-021-0408, Northwest Natural Gas Company, dba NW Natural, submits the enclosed Energy Burden Metrics Report for the fourth quarter 2025, using the template provided by Public Utility Commission of Oregon Staff.

Please address correspondence on this matter to me with copies to the following:

eFiling
Rates & Regulatory Affairs
NW Natural
250 SW Taylor Street
Portland, Oregon 97204
Telephone: (503) 610-7330
Fax: (503) 220-2579
Email: eFiling@nwnatural.com

Sincerely,

/s/ Natasha Siores

Natasha Siores
Senior Manager, Regulatory Affairs
NW Natural
250 SW Taylor Street
Portland, OR 97204
Telephone: (503) 610- 7074
Email: natasha.siores@nwnatural.com

Enclosures

cc: Bret Farrell

RO 16 - NWN 4Q 2025 Energy Burden Metrics Report

Oregon Public Utility Commission

Docket No. RO 16 - Energy Burden Metrics Report

Table 1: Utility Information

Line No.	Field	Response
1	Utility Name	NW Natural
2	Reporting Period	Fourth Quarter 2025
3	Date of Submission	

Table 2: Arrearage Information

Line No.	**Month**	October	November	December
	Year	2025	2025	2025
1	Total Customers in Arrears	54,805.00	59,813.00	50,279.00
2	31-60 Days in Arrears	22,198.00	26,762.00	21,615.00
3	61-90 Days in Arrears	10,161.00	10,695.00	10,121.00
4	91 or More Days in Arrears	22,446.00	22,356.00	18,543.00
5	Total Arrears Balance	$ 3,555,503.26	$ 4,419,369.14	$ 4,929,100.62
6	31-60 Days in Arrears	$ 1,385,986.29	$ 2,343,450.91	$ 2,922,085.62
7	61-90 Days in Arrears	$ 676,364.66	$ 742,516.18	$ 905,117.83
8	91 or More Days in Arrears	$ 1,493,152.31	$ 1,333,402.05	$ 1,101,897.17
9	Total number of customers enrolled in Time Payment Arrangements (TPA) or other extended payment plans	6,386.00	1,333,402.05	5,586.00

RO 16 - NWN 4Q 2025 Energy Burden Metrics Report

Table 3: Disconnection Information

Line No.	**Month**	October	November	December
	Year	2025	2025	2025
1	Total number of active residential accounts	648,125.00	649,408.00	650,437.00
2	Total number of service disconnections for non-payment	706.00	404.00	694.00
3	Percentage of accounts with service disconnections for non-payment	0.109%	0.062%	0.107%
4	Total number of disconnection notices sent to residential customers	6,658.00	7,302.00	19,865.00
5	Total number of bill discount recipient service disconnections for non-payment	274.00	139.00	213.00
6	Total number of energy assistance recipient service disconnections for non-payment	32.00	14.00	27.00
7	Total number of service disconnections for non-payment on medical certificate holder accounts	-	-	-

Table 3 Continued: Disconnection Information

Line No.	**Month**	October	November	December
	Year	2025	2025	2025
8	Number of service reconnections following a service disconnection for non‐payment on the same day or next calendar day following disconnection	298.00	175.00	325.00
9	Number of service reconnections following a service disconnection for non‐payment that occur more than one day and within 7 calendar days following disconnection	154.00	89.00	135.00
10	Number of days on which the energy utility was required to impose a moratorium on service disconnection for severe weather as required by OAR 860-021-0407	-	1.00	7.00

Table 4: Usage and Bill Information

Line No.	**Month**	October	November	December
	Year	2,025	2,025	2,025
1	Total Residential Usage	13,164,950.30	30,669,393.40	46,672,730.50
2	Average Residential Usage	20.30	47.20	71.73
3	Average Residential Bill	$ 39.32	$ 77.04	$ 123.53

RO 16 - NWN 4Q 2025 Energy Burden Metrics Report

Table 5: Bill Discount Program Information

Line No.	**Month**	October	November	December
	Year	2,025	2,025	2,025
1	Total number of residential customers which received a bill discount	47,295.00	48,027.00	48,662.00
2	Tier 1	11,983.00	12,056.00	12,142.00
3	Tier 2	13,872.00	14,099.00	14,268.00
4	Tier 3	12,797.00	13,037.00	13,245.00
5	Tier 4	8,643.00	8,835.00	9,007.00
6	Tier 5	-	-	-
7	Total dollars provided to bill discount program participants	$ 734,821.32	$ 1,459,765.13	$ 2,393,776.01
8	Tier 1	$ 65,605.24	$ 130,716.71	$ 212,159.57
9	Tier 2	$ 156,458.82	$ 311,920.16	$ 507,845.55
10	Tier 3	$ 237,530.46	$ 472,897.37	$ 773,667.06
11	Tier 4	$ 275,226.80	$ 544,230.89	$ 900,103.83
12	Tier 5	$ -	$ -	$ -
13	Total bill discount program costs	$ 734,821.32	$ 1,459,765.13	$ 2,393,776.01
14	Incremental administrative costs	$ -	$ -	$ -
15	Applied Credits	$ 734,821.32	$ 1,459,765.13	$ 2,393,776.01
16	Total number of new enrollments	1,287.00	1,098.00	1,445.00
17	Total number of disenrollments	891.00	783.00	1,136.00

Table 5 Continued: Bill Discount Program Information

Line No.	**Month**	October	November	December
	Year	2025	2025	2025
18	Average bill discount program participant usage	19.22	44.80	67.98
19	Tier 1	18.71	44.39	67.35
20	Tier 2	19.51	45.42	68.82
21	Tier 3	19.21	44.60	67.56
22	Tier 4	19.46	44.65	68.11
23	Tier 5	-	-	-
24	Pre-discount average bill discount program participant bill	$ 38.27	$ 73.71	$ 118.39
25	Tier 1	$ 37.73	$ 73.82	$ 118.35
26	Tier 2	$ 38.78	$ 75.11	$ 120.32
27	Tier 3	$ 38.79	$ 73.73	$ 118.58
28	Tier 4	$ 37.44	$ 71.29	$ 115.10
29	Tier 5	$ -	$ -	$ -
30	Post-discount average bill discount program participant bill	$ 22.73	$ 43.32	$ 69.20
31	Tier 1	$ 32.25	$ 62.98	$ 100.88
32	Tier 2	$ 27.50	$ 52.99	$ 84.73
33	Tier 3	$ 20.23	$ 37.46	$ 60.16
34	Tier 4	$ 5.60	$ 9.69	$ 15.17
35	Tier 5	$ -	$ -	$ -

Table 5 Continued: Bill Discount Program Information

Line No.	**Month**	October	November	December
	Year	2025	2025	2025
36	Total number of bill discount program participants with an arrearage balance	10,065.00	10,866.00	10,830.00
37	31-60 Days in Arrears	2,895.00	3,484.00	3,223.00
38	61-90 Days in Arrears	1,805.00	1,938.00	2,136.00
39	91 or More Days in Arrears	5,365.00	5,444.00	5,471.00
40	Total arrears balance of program participants	$ 602,826.12	$ 713,389.78	$ 901,710.48
41	31-60 Days in Arrears	$ 183,517.98	$ 292,314.43	$ 431,932.95
42	61-90 Days in Arrears	$ 109,305.24	$ 124,125.36	$ 176,391.72
43	91 or More Days in Arrears	$ 310,002.90	$ 296,949.99	$ 293,385.81

Appendix Table 1: Utility Bill Discount Program Information

LINE NO.	Utility Bill Discount Tier	SMI Range (%)	Discount
1	Tier 1	46% - 60% SMI	15%
2	Tier 2	31% - 45% SMI	30%
3	Tier 3	16% - 30% SMI	50%
4	Tier 4	0% - 15% SMI	85%
5	0	0	0

Oregon Public Utility Commission

e-FILING REPORT COVER SHEET

COMPANY NAME: NW Natural

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☐ No ☐ Yes If yes, submit a redacted public version (or a cover letter) by email. Submit the confidential information as directed in OAR 860-001-0070 or the terms of an applicable protective order.

Select report type: ☐ RE (Electric) ☐ RG (Gas) ☐ RW (Water) ☐ RT (Telecommunications)
☐ RO (Other, for example, industry safety information)

Did you previously file a similar report? ☐ No ☐ Yes, report docket number: RO 16

Report is required by: ■ OAR 860-021-0408
☐ Statute
☐ Order
Note: A one-time submission required by an order is a compliance filing and not a report (file compliance in the applicable docket)
☐ Other
(For example, federal regulations, or requested by Staff)

Is this report associated with a specific docket/case? ☐ No ☐ Yes, docket number: RO 16

List Key Words for this report. We use these to improve search results.

Energy Burden

Send the completed Cover Sheet and the Report in an email addressed to PUC.FilingCenter@state.or.us

Send confidential information, voluminous reports, or energy utility Results of Operations Reports to PUC Filing Center, PO Box 1088, Salem, OR 97308-1088 or by delivery service to 201 High Street SE Suite 100, Salem, OR 97301.

NW Natural®

250 SW Taylor Street
Portland, OR 97204

503-226-4211
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February 23, 2026

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
Post Office Box 1088
Salem, OR 97308-1088

Re: RO 16 – Energy Burden Metrics Report OAR 860-021-0408 – 2025 Annual Supplement

In compliance with OAR 860-021-0408, Northwest Natural Gas Company, dba NW Natural, submits the enclosed Energy Burden Metrics Report Annual Supplement for 2025.

Please address correspondence on this matter to me, with copies to the following:

eFiling
Rates & Regulatory Affairs
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Sincerely,

/s/ Natasha Siores

Natasha Siores
Senior Manager, Regulatory Affairs
NW Natural
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Portland, OR 97204
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Enclosures

cc: Bret Farrell

NW Natural
Energy Burden Metrics Report - Annual Supplement - 2025
Requirements per OAR 860-021-0408(7)(a)-(f)

2025	(a) High Usage Customers	(b) Average Usage	(c) Average Bill	(d) 31-60 Arrears Count	(d) 61-90 Arrears Count	(d) 91+ Arrears Count	(e) 31-60 Arrears Amt	(e) 61-90 Arrears Amt	(e) 91+ Arrears Amt	(f) Disconnects
January	4,467	205	$292.77	670	413	638	$241,577	$89,950	$106,258	14
February	4,532	218	$269.30	812	537	560	$298,297	$134,294	$102,061	26
March	4,596	154	$223.07	715	589	600	$287,824	$158,888	$119,519	52
April	4,681	112	$169.62	730	621	689	$261,120	$169,378	$145,890	52
May	4,006	74	$116.45	530	557	736	$188,294	$155,114	$165,142	49
June	4,686	59	$90.16	249	566	1,004	$83,323	$129,897	$214,180	51
July	4,723	38	$63.22	456	330	1,137	$98,270	$66,516	$196,152	63
August	4,647	33	$54.90	415	417	1,057	$71,083	$66,925	$155,627	54
September	4,653	34	$57.19	363	330	1,027	$59,067	$47,185	$132,081	47
October	4,761	56	$87.06	365	250	930	$49,997	$32,238	$121,755	37
November	8,627	73	$109.87	795	451	1,661	$150,428	$55,281	$179,529	27
December	5,302	148	$232.02	532	324	866	$142,113	$55,617	$88,066	26

Definitions per OAR 860-021-0408(1):

(e) "Average bill of high-usage customer" means the average monthly dollar amount the utility billed all high-usage customers.

(h) "Average usage of high-usage customers" means the average monthly energy consumption of all customers classified as high usage.

(m) "High-usage customer" means a residential customer participating in a utility-administered bill discount program whose energy consumption places them in the 90th percentile or above of all other bill discount program participants within the utility's service area.

(t) "Total arrears balance of high-usage customers" means the cumulative dollar amount of overdue balances of all high-usage customers in arrears during the reporting period.

NW Natural®

250 SW Taylor Street
Portland, OR 97204

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September 16, 2024

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
P.O. Box 1088
Salem, OR 97308-1088

Re: UM 2211 – NW Natural's Energy Burden Assessment

Northwest Natural Gas Company, dba NW Natural (NW Natural or Company), respectfully submits the results of its Energy Burden Assessment (EBA) in the timeframe identified by Public Utility Commission of Oregon (Commission) Staff's Phase 2 updates in docket UM 2211.

NW Natural contracted with Empower Dataworks to conduct an EBA in May of 2024. Empower Dataworks is a regional consulting firm specializing in energy equity analytics and has conducted similar assessments for numerous utilities throughout the Pacific Northwest.

The Company submits the complete EBA report, along with findings and recommendations as prepared by Empower Dataworks. The findings were presented to Commission Staff, UM 2211 stakeholders, and other stakeholders, including members of the Company's Washington GREAT Advisory Group on September 11, 2024. NW Natural welcomes stakeholder feedback as we begin to carefully evaluate the recommendations made by Empower Dataworks.

NW Natural knows how important it is to identify customers facing energy insecurity to design programs to mitigate these risks and target outreach efforts. Having the results of the EBA will enable NW Natural to develop new programs and/or enhance existing programs that our customers want and programs that help us best serve our energy-burdened customers. NW Natural completed its first EBA in 2022, and the Company is excited to bring this expanded 2024 EBA to the Commission and other interested parties.

NW Natural appreciates the opportunity to submit its EBA documents and remains fully committed to the UM 2211 process. Please contact me, with a copy to the following, with any questions on this filing.

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Respectfully submitted,

/s/ Natasha Siores

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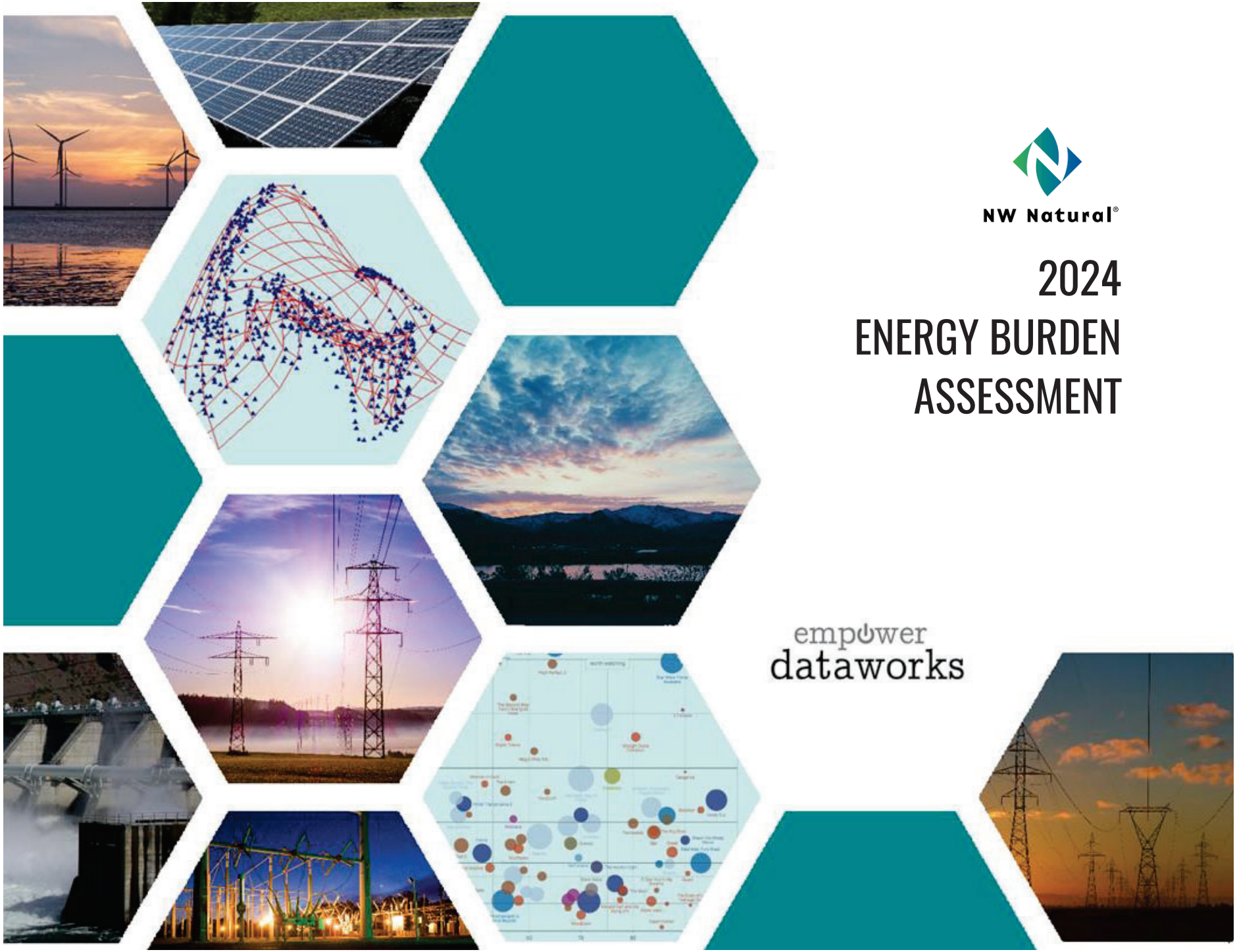
Attachment



NW Natural®

2024 ENERGY BURDEN ASSESSMENT

empower dataworks

2024 ENERGY BURDEN ASSESSMENT

AUGUST 2024

PREPARED FOR

Amy Schulties

Northwest Natural

PREPARED BY

Hassan Shaban, Ph.D.

Empower Dataworks

INTRODUCTION

This brief report presents the methodology and findings from NW Natural (NWN)'s 2024 energy burden assessment for Oregon and Washington.

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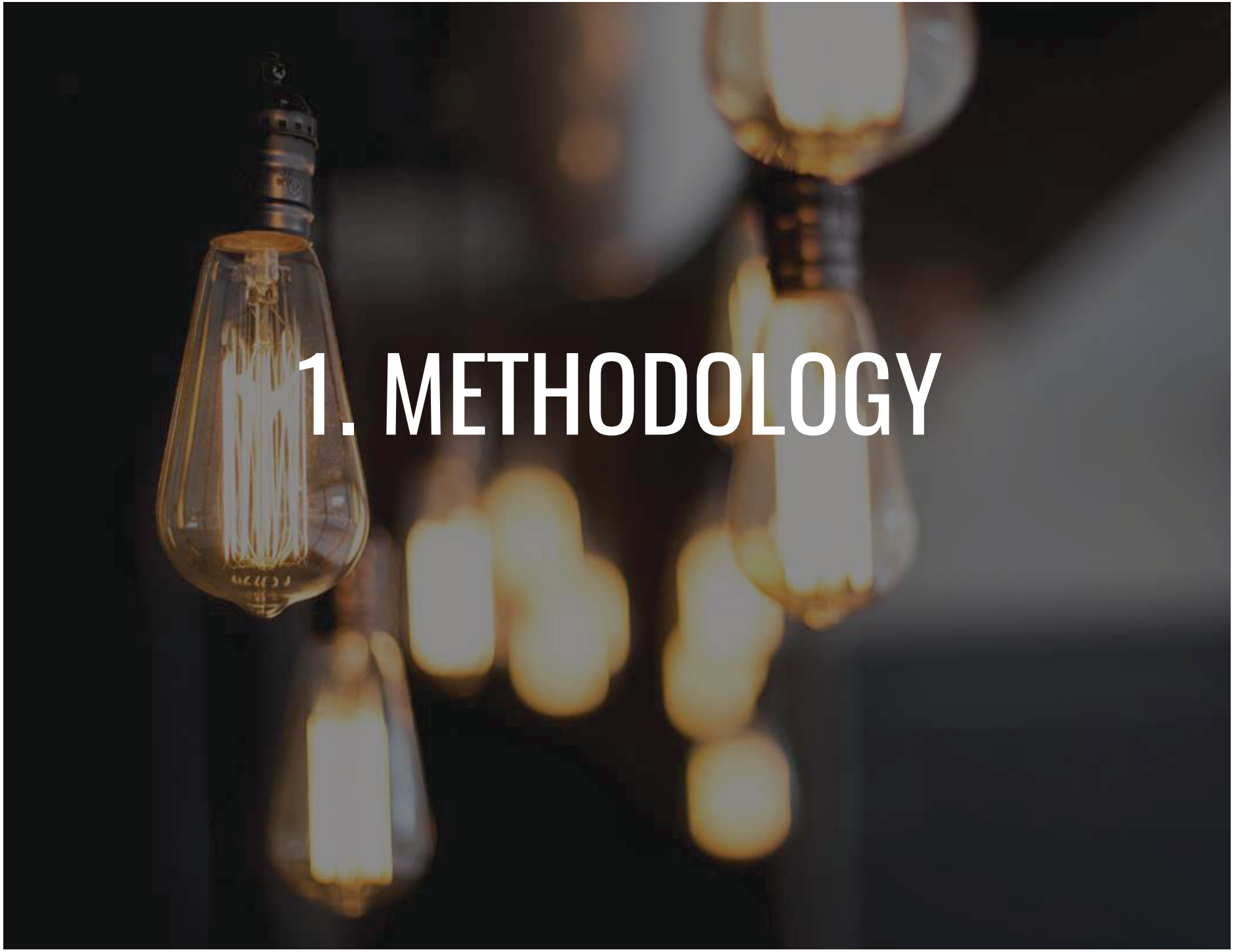


1. METHODOLOGY

1.1 GENERAL APPROACH

This energy burden assessment relies on collecting customer-level data, modeling missing attributes, then aggregating key metrics by geographic, demographic or building variables for analysis. Prior to this project, Empower Dataworks performed energy burden assessments in over 15 utility service areas (both gas and electric) using this approach. The methodology is also updated occasionally to align with energy assistance best practices. The energy burden assessment results are typically used to guide program design, evaluate the performance of energy assistance programs and develop targeted marketing and outreach strategies.

The customer data (including estimated household income) comes from various sources as described in the rest of Section 1. Some demographic attributes were modeled or inferred using statistical techniques due to lack of primary data in the Customer Information System (CIS) or other sources. American Community Survey data was mainly used to sanity check aggregate statistics of customer-level data at the census tract level.

Three types of metrics were calculated:

- Metrics related to energy burden based on demographic and geographic characteristics
- Participation and funding in Energy Assistance Programs
- Customer energy use characteristics

The final dataset and results were provided to NWN staff.

1.2 DATA SOURCES

The data sources leveraged for the analysis are described in this section.

DATA PROVIDED BY NWN

NWN provided various customer-level datasets to Empower Dataworks to enable this analysis. Data sharing was governed by a confidentiality agreement between Empower Dataworks and NWN. Empower Dataworks was also subject to various cybersecurity requirements to safeguard customer data.

Customer Information System (CIS): This data included monthly gas bills for 27 months between January 2022 and March 2024, account numbers and service addresses. A separate data extract included the dates and customer accounts that received late payment and disconnection notices, allowing us to calculate the on-time payment rate for different customer segments.

Direct Assistance Program Data: We received a list of participating accounts in the Bill Discount Program (BDP), other NWN low-income programs (OLGA, GREAT, GAP, LIEE), and LIHEAP between January 2022 and March 2024, along with discount amounts and dates. This allowed us to calculate the total assistance funding at the household level.

Demographic Data: Demographic data was procured from a third-party data compiler that aggregates data from a variety of sources. This data was mapped to the CIS dataset using customer addresses and included estimated household income, and homeownership status for most residential households. Demographic attributes for some customers were modeled due to lack of primary data in CIS or other sources. The modeling approaches are described in the next section.

DATA OBTAINED FROM OTHER SOURCES

Geocoding: We mapped the latitude/longitude of customer premises to census tracts, block groups and blocks in order to pull additional aggregate statistics.

County Assessor Data: We obtained publicly available assessor data from all counties in NWN's service area. The data from most assessors included appraised values for homes, square footage, building year built, land use codes (residential, mobile homes, commercial and industrial), and other minor data points that were useful for performing general QA.

The addresses in this dataset were standardized to US Postal Service format, then matched with addresses in the CIS data. Some addresses existed in the CIS data but not in the assessor data (typically happens when multiple buildings occupy the same land parcel).

American Community Survey (ACS): ACS data (2018-22 5 year averages) was primarily used for QA to ensure that aggregate counts for various demographic attributes match the expected distributions from ACS.

1.3 FINAL ATTRIBUTES AND METRICS

The calculation methods for the metrics and attributes used in this report are described in this section. For all attributes, we also captured metadata related to the source of data and the confidence in the value (for example, data from primary sources has a high confidence, while modeled data has lower confidence). All of the data is robust for aggregate analysis, while high confidence data is better suited to customer-level marketing and program targeting.

Household Income: Estimated household incomes were obtained using three methods: (i) self-attested incomes for program participants, (ii) third-party purchased and calibrated demographic data, and (iii) modeled income for households with missing data. Self-attested household income was available for about 45,000 households that had participated in the BDP and declared their household income. Third-party estimated income data is sourced from public or commercially available data sources. Since household income from data vendors can become outdated quickly, we adjusted the unverified household incomes by a constant percent, so that the median household income in each county matched the median household income from the DOE LEAD tool and the Federal Reserve's FRED tool. For households with missing income data, an estimated income was calculated as the average of the incomes of the five geographically closest households.

Poverty Status: The number of people living in a household cannot be easily obtained from any public data sources. This makes it difficult to identify a household's poverty status compared to the State Median Income, which is defined by household size. According to the Census Bureau, the median household size in the NWN counties varies from 2.2 to 2.8. In general, we used the income limits for two person households in this analysis as they produced the best estimates of state median income tiers compared to the DOE LEAD tool.

Validation: According to the DOE LEAD tool, between 10-18% of gas-heat households in the four largest Oregon counties served by NWN would fall under 60% of the State Median Income. In this assessment, the county poverty rates range from 9-17% (with an approximately

10% margin of error), which is within the census range. The LEAD tool estimates that 24% of gas-heat customers in Clark County, WA fall under 80% of the Area Median Income, compared to 23% estimated through this assessment.

Building type: Meters were classified into one of five building types: single family, mobile homes, multifamily apartments, commercial or master metered and unoccupied. Commercial meters were those tagged with a specific commercial use by the county assessor or that were on a commercial rate class. Additionally, we filtered out meters using in excess of 3,600 Therms per year as those are likely associated with commercial uses or are master metered. Meters that showed energy consumption less than 60 Therms/year were flagged as potentially unoccupied or vacation homes.

Overall, the number of residential meters was 706,000. When excluding high-use and low-use outliers (suspected seasonal, unoccupied or master-metered), the final number of occupied households for the analysis was approximately 645,000 (567k in OR, 78k in WA). NWN provided internal data to identify single family and multifamily building types – this was used in conjunction with county assessor land use codes to categorize building types.

Validation: The aggregate housing type counts (85-89% single family) are very similar to data from the DOE LEAD tool for the five largest counties in NWN's service area.

Homeownership Status: Some homeownership data (rent vs. own) was available from NWN and the third party demographic dataset. For the remainder, households in multifamily apartments were tagged as "Likely Renters", and households without any account changes during the two year analysis period were tagged as "Likely Homeowners".

Validation: The owner-occupied housing rate from the DOE LEAD tool for the five largest counties in NWN's service area (80-85%) is slightly lower than the homeownership rate from this analysis (85-90%).

Energy Burden and Energy Efficiency Potential thresholds: These thresholds were set as follows:

- High-burden threshold: Greater than 2% in marine climate counties and greater than 3% in cold climate counties – using climate zones defined by DOE. Cold climate counties (1% of households): Hood River, Wasco (OR), Klickitat, Skamania (WA).
- High efficiency potential threshold: Greater than 0.6 therms/sq.ft.

Gas Burden: Gas energy burden for a household is calculated simply by dividing annual gas expenses by gross household income.

$$Gas\ Burden\ [\%] = \frac{Annual\ Gas\ Expenses\ [\$]}{Annual\ Household\ Income\ [\$]}$$

Excess Burden: Excess burden is the portion of a household's gas burden in excess of the high burden threshold.

$$\begin{aligned} Excess\ Burden\ [\$] \\ &= \max(0, Energy\ Burden\ [\%] \\ &\quad - High\ Burden\ Threshold[\%]) \\ &\quad \times Annual\ Household\ Income[\$] \end{aligned}$$

On-Time Payment Rate: This is the proportion of all energy bills that did not require a late payment or disconnect notice to be sent out.

Energy Assistance Funding: The dollar amount of funding flowing through energy assistance programs (including discount, donation and weatherization programs) through discounts or rebates.

Customer Bill Reductions (**Avoided Burden**)**:** The total bill impact (in dollars) from energy assistance programs.

Avoided Need: The total bill impact (in dollars) from energy assistance programs, specifically for program participants flagged as "high-burden". Bill impact is equal to the amount of assistance grants or discounts for direct assistance programs and is equal to measure savings (therms/year) multiplied by the residential therms rate ($/therms) for energy efficiency programs.

Census Tract Statistics: Since each customer has been mapped to a census tract and block group, we are also able to match customers to census tract average statistics (e.g. highly impacted communities, presence of children, non-English speakers, education level, environmental pollution etc.).

Energy Assistance Need: This is the sum of excess burden across all customers.

2024 Projections: Since NWN customers experienced a rate change in November 2023, some figures in this assessment related to need and energy burden are projections for 2024 including the impact of the rate change. The 2024 energy bills were projected by using the 2023 energy usage for customers and applying the 2024 rate structure. 2024 household incomes were estimated by adding a 7% multiplier to the estimated 2023 household incomes (LIHEAP applied a 7% income adjustment to their 2024 income guidelines compared to 2023). This will be noted where relevant.

1.4 SOURCES OF UNCERTAINTY

- **Household income** is a dynamic piece of data as residents move in and out of homes and income data can become outdated within a year or two.

- **Poverty status.** Since household size cannot be reliably captured through any available data source, household poverty status is subject to uncertainty. The State Median Income uses household size as a scaling factor. In this analysis, we have used income thresholds for 2-person households for consistency and clarity, but they may under-estimate or over-estimate the actual income eligibility depending on the actual sizes of low-income households in this service area.

- **Individual vs. aggregate data usage.** The underlying dataset has customer-level flags for data quality – data from primary sources is considered high quality while modeled data is considered medium or low quality, depending on the availability of supporting sources of information (example, home values and location). Higher quality data can be used for individual program targeting, lower quality data can be used for program design and aggregate reporting.

- **Building types.** There is some uncertainty in the classification of building types as described in Section 1.3. This could results in misclassifying non-residential meters as occupied households or single family/mobile homes as multifamily.

- **Achievable reductions in energy assistance need.** This analysis presents a *technical* energy assistance need based on energy burden. However, in our experience with energy assistance programs in general, many customers may not participate in programs, regardless of program design or available benefits due to a variety of barriers like access to information, application process difficulties, stigma and lack of trust. Understanding the *economically achievable* reduction in energy assistance need through utility programs would require a qualitative research of non-participants in a utility's service area.

2. NWN'S ENERGY BURDEN BASELINE - OREGON

2.1 NWN RESIDENTIAL SECTOR PROFILE - OR

NWN's service territory in Oregon was composed of approximately **567,000 occupied households** in 2023 (exceeding a minimal level of 60 therms/year of energy use and not exceeding 3,600 therms/year).

Ethnicity: According to the U.S. Census Bureau, approximately 62-78% of residents in NWN's largest counties are non-Hispanic white.

Household Income: The median household income for residents in NWN's service area was approximately $114,000 in 2024, significantly higher than the state median. Approximately **12.5%** of residents would fall under 60% of the State Median Income (see table on following page for SMI values). An additional 13% of households earn between 60-100% of the state median income. These "borderline" customers would be ineligible for almost all energy assistance programs, but may still bear a relatively high level of energy burden. Designs for programs that are ratepayer-funded should take into account the degree of additional burden that would be imposed on these customers.

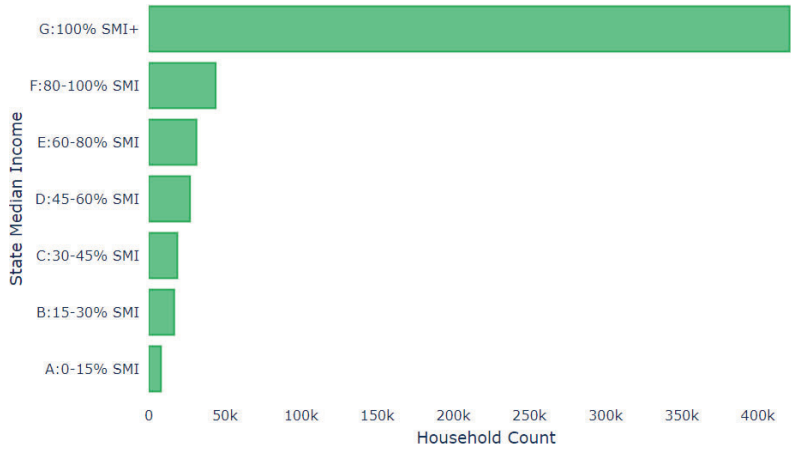


Figure 1. Distribution of households by household income as a percent of state median income for NWN residential customers

	60% of Annual State Median Income (SMI)	
Household Size	2023	2024
1	$31,266	$33,427
2	$40,886	$43,712
3	$50,506	$53,997
4	$60,126	$64,282
5	$69,747	$74,567
6	$79,367	$84,852
Each additional member	$1,803	$1,929

Energy Bills: NWN's residential volumetric gas rates in 2024 were about average for the region, and the basic charge is relatively low. Annual gas bills average **approximately $1,100/year (2024 projection) with an average annual consumption of 720 therms**. Figure 2 shows the distribution of annual gas bills.

Home Vintage: Of the homes with a known age, approximately 48% were built after 1980, 36% were built between 1940 and 1980, with the remainder built prior to 1940. Older homes have more opportunities for weatherization, while newer homes could benefit more from lighting, controls and efficient appliances.

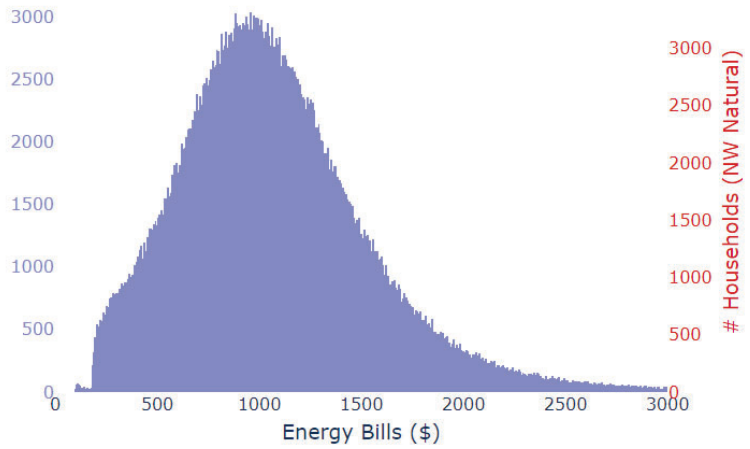


Figure 2. 2024 Household gas bill distribution for NWN residential customers in Oregon

2.2 ENERGY BURDEN

NWN customers in Oregon have an **average and median gas energy burden of 1.4% and 0.9%**, respectively. Figure 3 compares NWN's median total energy burden (including an estimate of electricity burden) to values published in other jurisdictions. The median burden is between other rural and metropolitan regions in the Pacific Northwest.

The average household will pay $1,100/year in gas bills in 2024. Of 567,000 identified households, **75,000 were deemed to have a high energy burden**, of which an estimated 50,000 would fall under 60% State Median income - meaning that annual gas bills exceeded 2/3% of their income, depending on their climate zone. Low-income high-burden customers paid an average of $1,100 in annual gas bills as well; indicating that the high burden is driven by low incomes rather than high gas usage. The **total energy assistance need for NWN customers in Oregon is approximately $38M across all incomes and $29M in households that earn under 60% SMI**—this is the total reduction that would bring all customer gas bills below the high burden threshold.

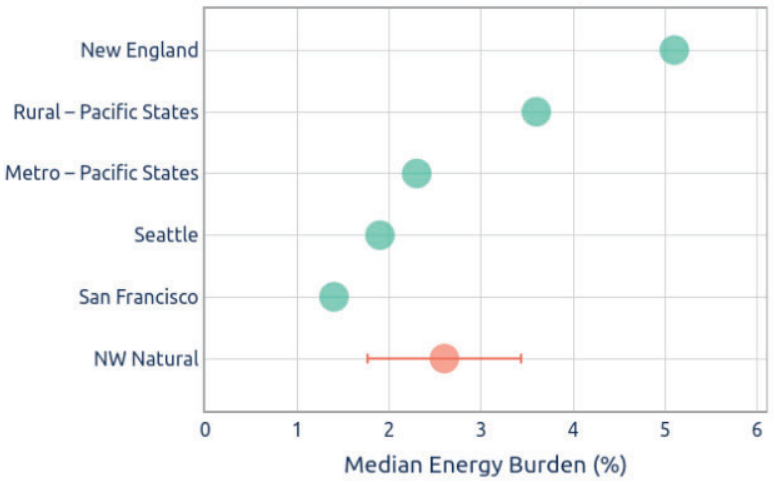


Figure 3. Energy burden benchmarking vs. other regions. Data for other regions is the median across each region, not specific to any utility.

NWN's energy charge in its 2024 residential retail rate is approximately $1.3/therm, which is similar to other gas utilities in the region and slightly lower than the national average of $1.45/therm. Low incomes appear to be the most significant drivers of high energy burden in the area for a minority of customers.

Although averages and medians give a general indication of energy burden across a service territory, the reality is that **energy burden is a customer-level metric** and its distribution is a better indicator of the burden that

customers experience. The distribution of energy burden among NWN customers is shown in Figure 4.

The goal of an effective energy assistance portfolio should be to prioritize the customers who most need the assistance, i.e. the customers exceeding the high burden thresholds.

Approximately 84% of the energy assistance need is borne by single family households. Only 15-20% of the energy assistance need for NWN customers in Oregon is among renters – high-burden single-family homeowners represent a promising opportunity for eliminating gas burden through energy efficiency or weatherization. Other customer segments can be investigated in more detail in the data dashboard.

Number of Occupied Households

~567,000

Low Income Households Under 60% SMI:

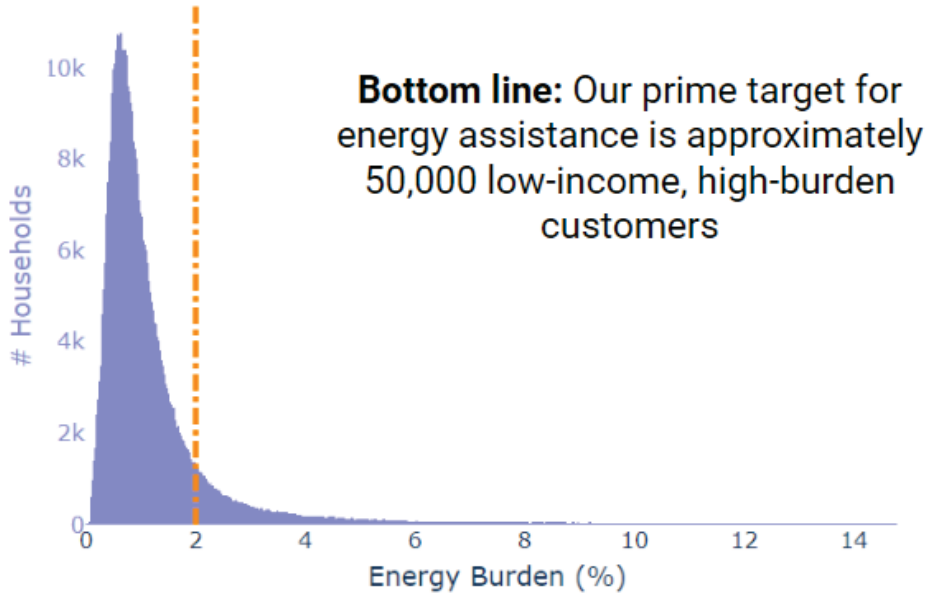
~71k ± 10%

High Burden Households*

~75,000 (all)

~50,000 (LI)

Median Gas Burden
~0.9% (all)
~3% (LI)



Bottom line: Our prime target for energy assistance is approximately 50,000 low-income, high-burden customers

*Energy bills and burden are calculated without factoring in any forms of energy assistance

Figure 4. Distribution of energy burden among NWN customers in Oregon.
Figure shows all homes but dashed line indicating 2% high energy burden threshold applies to marine climate counties (99% of all households).

2.3 ENERGY EFFICIENCY VS DIRECT ASSISTANCE

Figure 5 shows the distribution of energy burden and energy efficiency potential (defined through Energy Use Intensity thresholds) across all low-income residential customers. In a perfect world, the energy assistance portfolio would match these customer segments. For example:

- Energy efficiency and weatherization programs should primarily serve **high burden, high potential** households
- Direct assistance programs should primarily serve **high burden, low potential** households
- Crisis/emergency programs should primarily serve **low burden, low potential** households
- Traditional energy efficiency programs with financing should serve **low burden, high potential** households

Aligning targeted customers with program strengths results are the most cost-effective pathway to energy burden reduction.

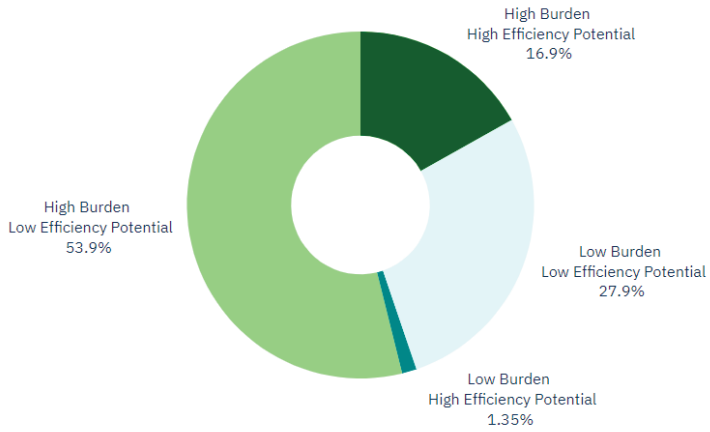
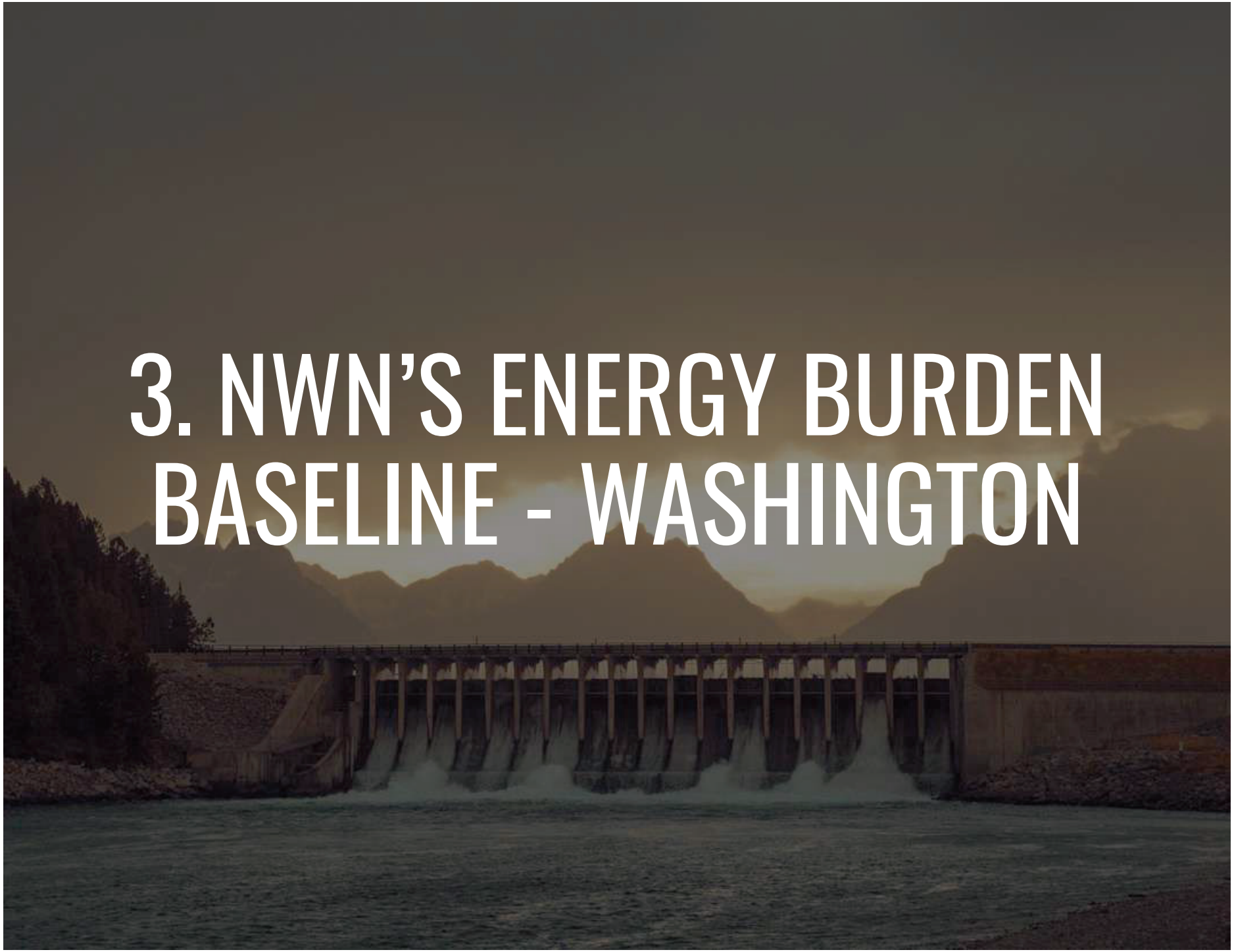


Figure 5. NWN low-income customer segments by energy burden and energy efficiency potential.

Approximately 28% of NWN's low-income customers are low-burden and low-efficiency potential. These customers' energy bills may not be a huge expense relative to housing, medical and education expenses, and they should not be prioritized in the more intensive programs, such as weatherization.

Almost 24% of high burden customers also have a high efficiency potential indicating that the energy assistance program mix should prioritize immediate relief through bill discounts. While energy efficiency is a more sustained form of energy burden reduction, we should recognize that scaling up low-income weatherization faces a host of barriers. Energy efficiency and direct assistance are not mutually exclusive and there is still a large group of households who would benefit most from energy efficiency to alleviate their high gas burden.



3. NWN'S ENERGY BURDEN BASELINE - WASHINGTON

3.1 NWN RESIDENTIAL SECTOR PROFILE - WA

NWN's service territory in Washington was composed of approximately **78,000 occupied households** in 2023 (exceeding a minimal level of 60 therms/year of energy use and not exceeding 3,600 therms/year).

Ethnicity: According to the U.S. Census Bureau, approximately 73% of residents in Clark County are non-Hispanic white.

Household Income: The median household income for residents in NWN's service area was approximately $123,000 in 2024, significantly higher than the state median. Approximately **23%** of residents would fall under 80% of the Area Median Income (see table on following page for AMI values). An additional 11% of households earn between 80-100% of the area median income. These "borderline" customers would be ineligible for almost all energy assistance programs, but may still bear a relatively high level of energy burden. Designs for programs that are ratepayer-funded should take into account the degree of additional burden that would be imposed on these customers.

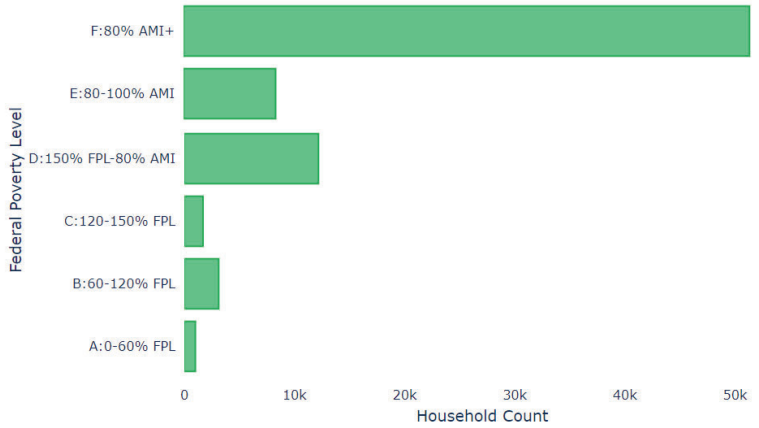


Figure 6. Distribution of households by household income as a percent of federal poverty level and area median income for NWN residential customers

	80% of Annual Area Median Income (AMI) – Clark County, WA	
Household Size	2023	2024
1	$63,150	$66,100
2	$72,200	$75,550
3	$81,200	$85,000
4	$90,200	$94,400
5	$97,450	$102,000
6	$104,650	$109,550
Each additional member	$7,200	$7,550

Energy Bills: NWN's residential volumetric gas rates in 2024 were about average for the region, and the basic charge is relatively low. But the inclusion of the $0.5/therm CCA charge drives up the cost of gas significantly for customers who haven't been certified as low-income. Annual gas bills average **approximately $1,340/year (2024 projection – not including potential CCA credits which are hard to predict) with an average annual consumption of 740 therms**. Figure 7 shows the distribution of annual gas bills.

Home Vintage: Of the homes with a known age, approximately 86% were built after 1980, 11% were built between 1940 and 1980, with the remainder built prior to 1940. Older homes have more opportunities for weatherization, while newer homes could benefit more from lighting, controls and efficient appliances.

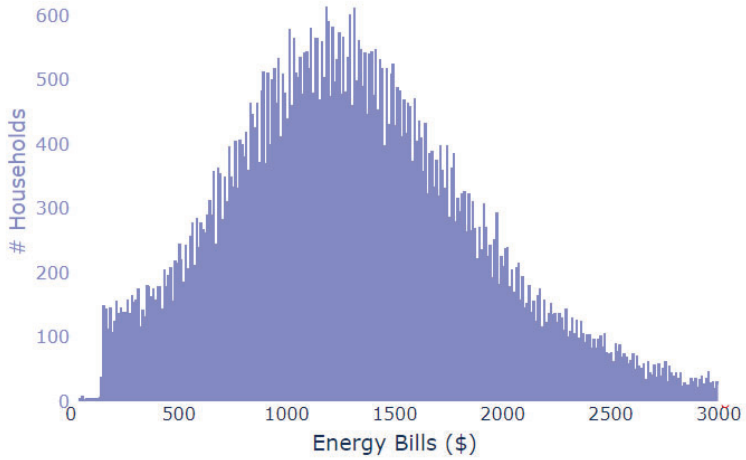


Figure 7. 2024 Household gas bill distribution for NWN residential customers in Oregon

3.2 ENERGY BURDEN

NWN customers in Washington have an **average and median gas energy burden of 1.5% and 1.0%**, respectively. Figure 8 compares NWN's median total energy burden (including an estimate of electricity burden) to values published in other jurisdictions. The median burden is between other rural and metropolitan regions in the Pacific Northwest.

The average household will pay $1,340/year in gas bills in 2024. Of 78,000 identified households, **13,000 were deemed to have a high energy burden**, of which an estimated 10,000 would fall under 80% Area Median income - meaning that annual gas bills exceeded 2/3% of their income, depending on their climate zone. Low-income high-burden customers paid an average of $1,380 in annual gas bills, despite most being exempt from the CCA charges; indicating a higher likelihood of living in less efficient homes. The **total energy assistance need for NWN customers in Washington is approximately $7.3M across all incomes and $5.9M in households that earn under 80% AMI**—this is the total reduction that would bring all customer gas bills below the high burden threshold.

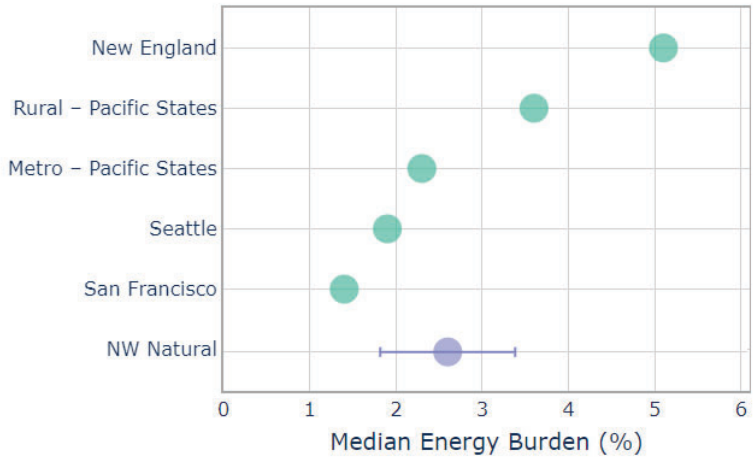


Figure 8. Energy burden benchmarking vs. other regions. Data for other regions is the median across each region, not specific to any utility.

NWN's energy charge in its 2024 residential retail rate is approximately $1.7/therm (inclusing Washington CCA charges), which is higher than other gas utilities in the region and the national average of $1.45/therm. Higher gas use coupled with the CCA charges appear to be a big driver of high energy burden in the region.

Although averages and medians give a general indication of energy burden across a service territory, the reality is

that **energy burden is a customer-level metric** and its distribution is a better indicator of the burden that customers experience. The distribution of energy burden among NWN customers is shown in Figure 9.

The goal of an effective energy assistance portfolio should be to prioritize the customers who most need the assistance, i.e. the customers exceeding the high burden thresholds.

Approximately 88% of the energy assistance need is borne by single family households. Only 9-10% of the energy assistance need for NWN customers in Washington is among renters – high-burden single-family homeowners represent a promising opportunity for eliminating gas burden through energy efficiency or weatherization. Other customer segments can be investigated in more detail in the data dashboard.

Number of Occupied Households

~78,000

Low Income Households Under 80% AMI:

~18k ± 10%

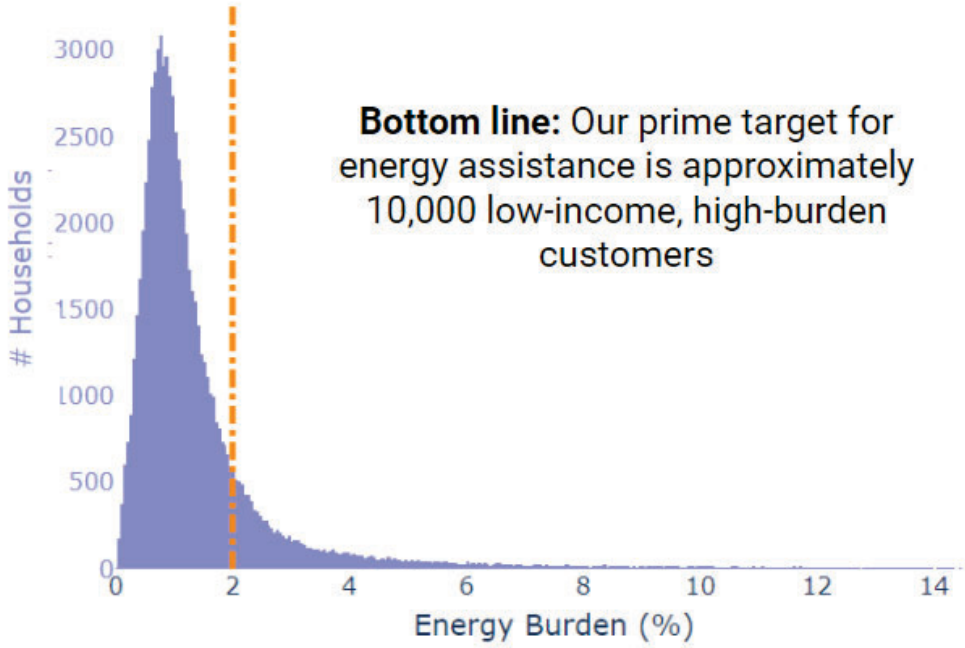
High Burden Households*

~13,000 (all)

~10,000 (LI)

Median Gas Burden

~1% (all)
~2.2% (LI)



Bottom line: Our prime target for energy assistance is approximately 10,000 low-income, high-burden customers

*Energy bills and burden are calculated without factoring in any forms of energy assistance

Figure 9. Distribution of energy burden among NWN customers in Washington.
Figure shows all homes but dashed line indicating 2% high energy burden threshold applies to marine climate counties (99% of all households).

3.3 ENERGY EFFICIENCY VS DIRECT ASSISTANCE

Figure 10 shows the distribution of energy burden and energy efficiency potential (defined through Energy Use Intensity thresholds) across all low-income residential customers. In a perfect world, the energy assistance portfolio would match these customer segments. For example:

- Energy efficiency and weatherization programs should primarily serve **high burden, high potential** households
- Direct assistance programs should primarily serve **high burden, low potential** households
- Crisis/emergency programs should primarily serve **low burden, low potential** households
- Traditional energy efficiency programs with financing should serve **low burden, high potential** households

Aligning targeted customers with program strengths results are the most cost-effective pathway to energy burden reduction.

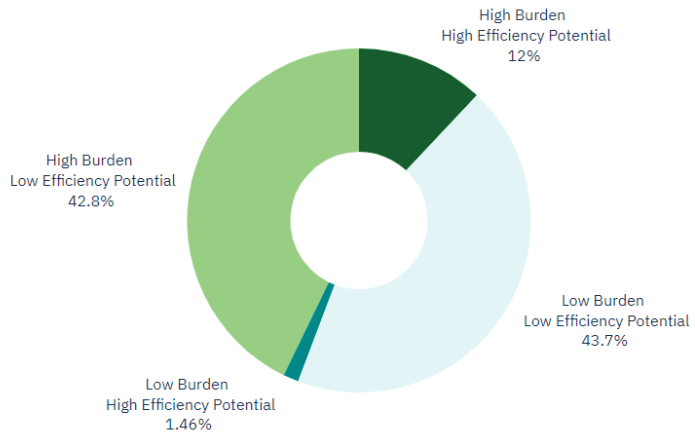


Figure 10. NWN WA low-income customer segments by energy burden and energy efficiency potential.

Approximately 44% of NWN's low-income customers in Washington are low-burden and low-efficiency potential. These customers' energy bills may not be a huge expense relative to housing, medical and education expenses, and they should not be prioritized in the more intensive programs, such as weatherization.

Almost 22% of high burden customers also have a high efficiency potential indicating that the energy assistance program mix should prioritize immediate relief through bill discounts. While energy efficiency is a more sustained form of energy burden reduction, we should

recognize that scaling up low-income weatherization faces a host of barriers. Energy efficiency and direct assistance are not mutually exclusive and there is still a large group of households who would benefit most from energy efficiency to alleviate their high gas burden.

4. KEY CUSTOMER SEGMENTS

4.1 OVERVIEW

This section presents statistics and profiles related to some key customer segments in NWN's service area. These customer segments were selected for a combination of reasons:

1. Flagged in this assessment as having high overall burden or high prevalence of energy burden

2. Identified as having low access to existing programs

3. Identified as vulnerable through the Department of Energy's environmental justice screen

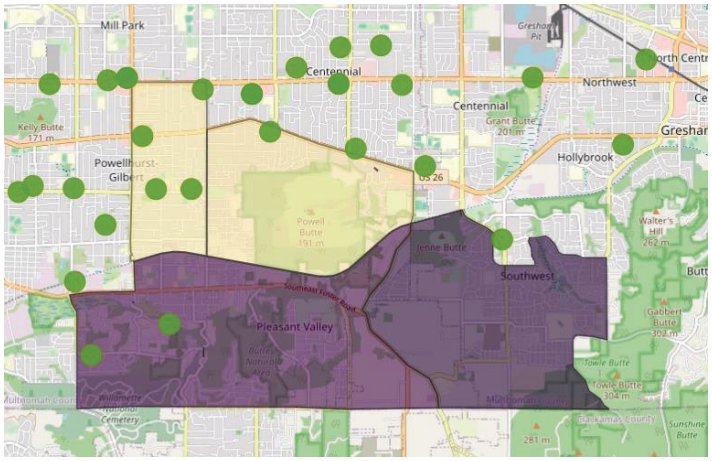
This analysis is primarily geographic, focusing on specific neighborhoods. The maps in the following sections display the level of energy assistance need in these areas as well as locations of social services for potential outreach (green dots).

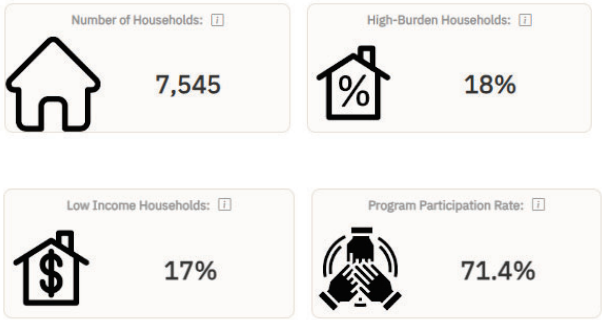
These customer segments represent only a portion of the high energy burden among NWN's customers, but they are intended to serve as an example of the targeting analysis that NWN can perform for their programs or outreach initiatives in the future.

4.2 PLEASANT VALLEY

Census tracts: **41051008901, 41051009000, 41051009102, 41051009903**

Total Assistance Need: **$745k (1.6% of total need)**
Total Assistance Funding: **$414k (2.5% of total funding)**
People of Color: 38%
Linguistic Isolation: 8%





PROFILE: The Pleasant Valley neighborhood in Eastern Multnomah county is a very diverse community with over 38% people of color and over 8% of the population living in linguistic isolation (mix of Spanish, Asian and East European). Members of this community tend to be single family homeowners. On the other hand, it appears to be well served by existing assistance programs.

RECOMMENDATIONS: Households in this area already have very high participation rates, yet the energy assistance funding only covers 56% of the need. It is evident that higher benefits or connecting participants to additional programs may be needed to fully alleviate gas burden.

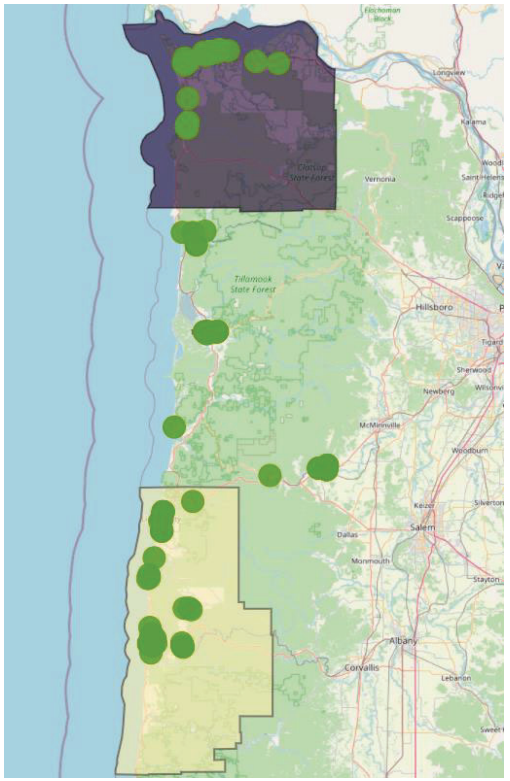
4.3 COASTAL AREAS

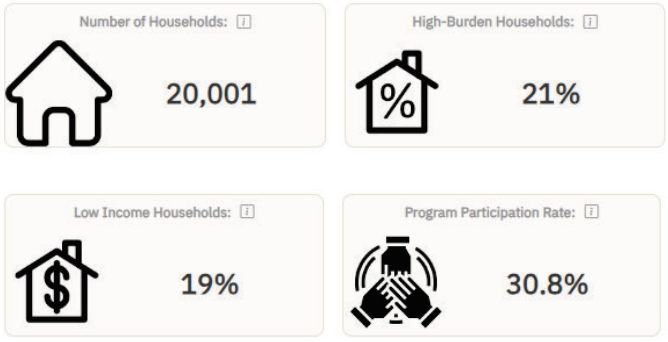
Total Assistance Need: **$2.1M (4.6% of total need)**

Total Assistance Funding: **$0.4M (2.4% of total funding)**

PROFILE: Clatsop and Lincoln counties are characterized by smaller towns and rural areas. Households in these areas experience moderate energy burden – 21% of households are considered high burden. The region was flagged for having relatively low participation rates. Most of these residents are single family homeowners.

RECOMMENDATIONS: Consult with local community-based organizations on the best approach to reaching potentially eligible households. Locally targeted marketing campaigns might be effective at reaching customers as well as collaborating with schools and local.





empower dataworks
www.empowerdataworks.com

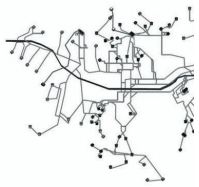
NW Natural

2024 Energy Burden Assessment

Findings (Oregon)

empower dataworks

What is an Energy Burden Assessment?



Data analysis (not a survey) that uses utility and third-party customer data.

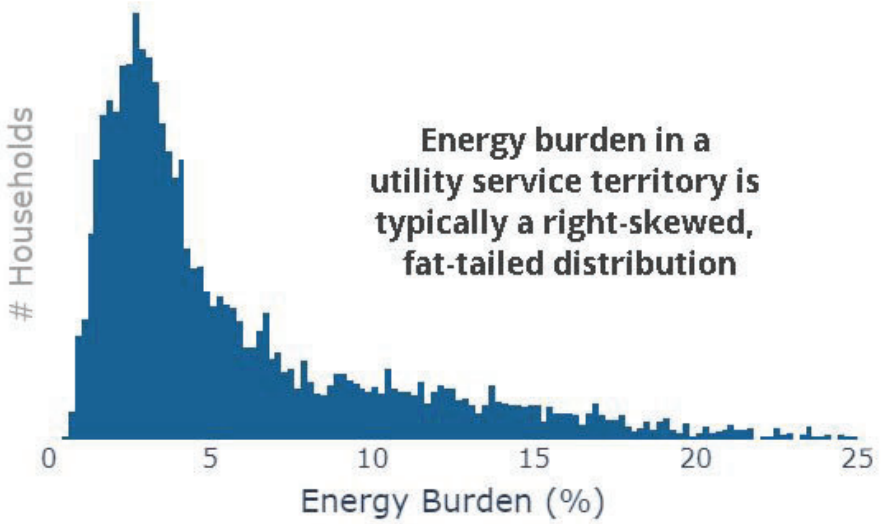
Primary purpose is to estimate the energy assistance need based on customer-level geographic, demographic and building data.

Comparing the need to actual program performance gives us an **actionable** path to improving our energy assistance programs

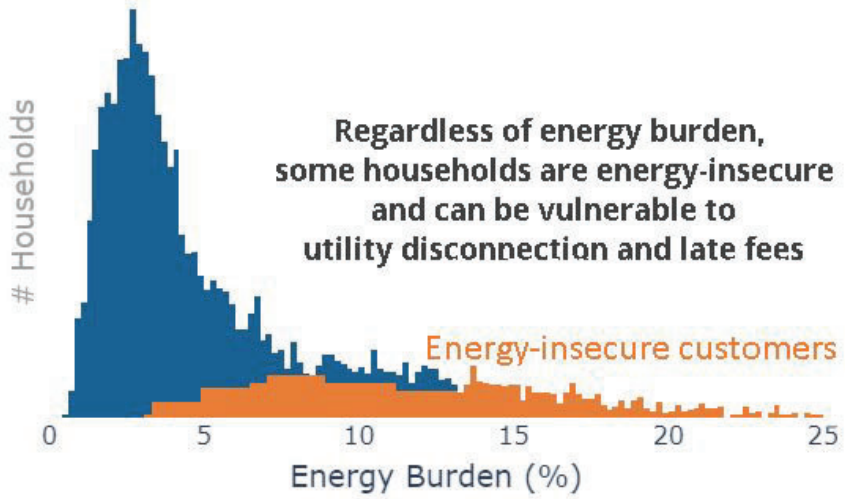
Energy Burden

The primary metric of success is reduction in energy insecurity

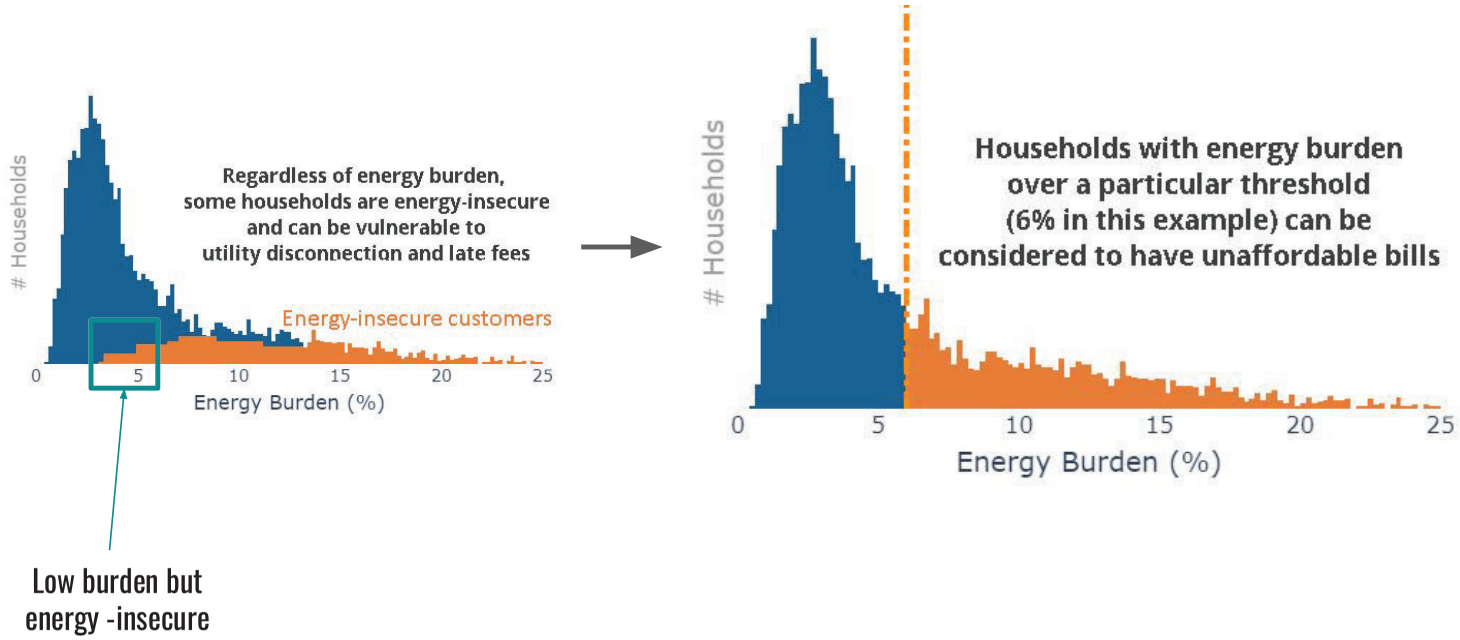
Energy Burden is a Distribution



Energy Insecurity is Harder to Measure



Energy Burden is a Proxy for Energy Insecurity



Definitions

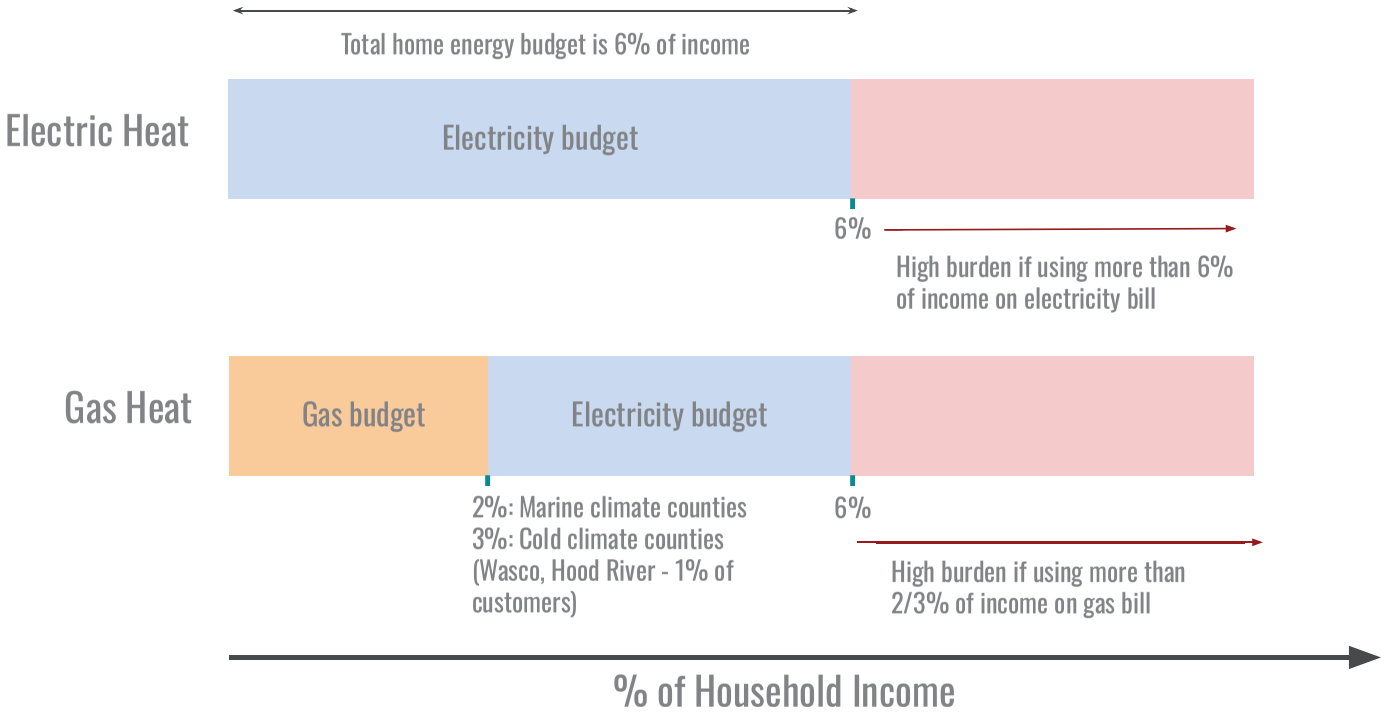
Low-income (Oregon):

Households earning under 60% of the state median income (SMI)

Household Unit Size	Annual Gross Income
1	$33,427
2	$43,712
3	$53,997
4	$64,282
5	$74,567
6	$84,852

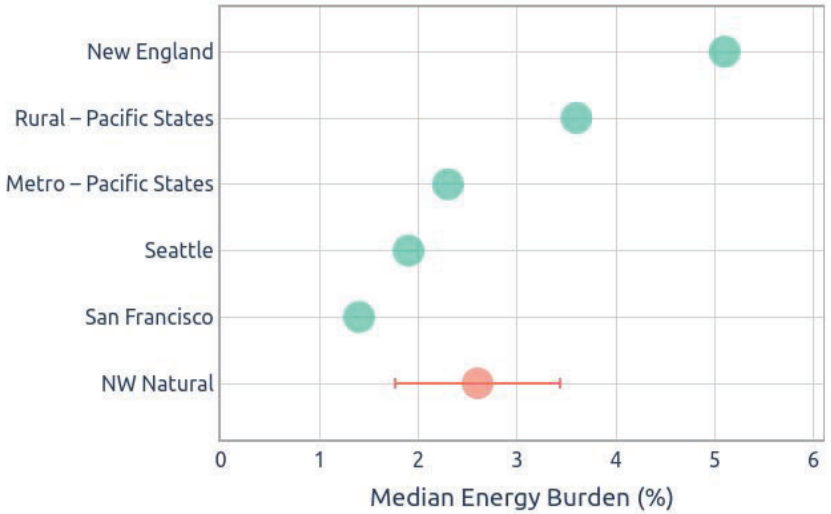
**Most data is reported for the 2023 calendar year. Bills and energy burden are projected for 2024 using 2024 rates and 2023 energy usage. 2024 household incomes are estimated to be 7% over 2023 incomes on average (equal to state median income increase)*

High burden thresholds for multiple fuels



Insights: **Energy Burden**

- ➔ Median total energy burden (~2.6%) is comparable to other metropolitan areas in the Pacific Northwest.
- ➔ Rates are average for the region and NW Natural customers have relatively higher incomes than the general population and experience mostly mild winters.



Insights: **Energy Burden (Oregon)**

Number of Occupied Households

~567,000

Low Income Households Under 60% SMI:

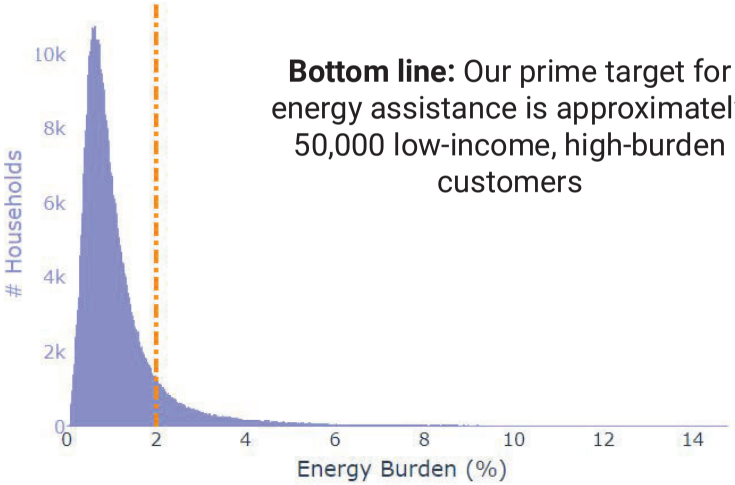
~71k ± 10%

High Burden Households*

~75,000 (all)

~50,000 (LI)

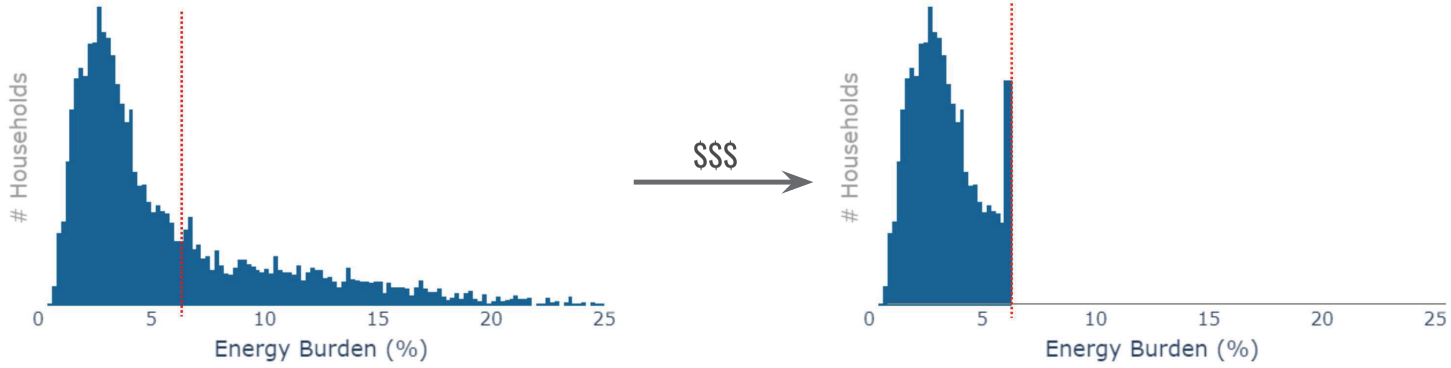
Median Gas Burden
~0.9% (all)
~3% (LI)



Bottom line: Our prime target for energy assistance is approximately 50,000 low-income, high-burden customers

*Energy bills and burden are calculated without factoring in any forms of energy assistance

Energy Assistance Need



Insights: **High-level Assistance Gap (Oregon)**

Low-Income, High Burden Households

~50,000

Income-eligible only

2024 Projection not including additional program participation.
Bill Discount Program (BDP): ~$8.3M

2025: $12M BDP, $18M total - 62% of need

➔ At program maturity (year 5+), best practice is to target at least 60-70% of the need available as program funding - with proposed 2025 rates, BDP would need additional participation. Once this target is reached, participation usually slows down and focus shifts to program optimization and targeted outreach.

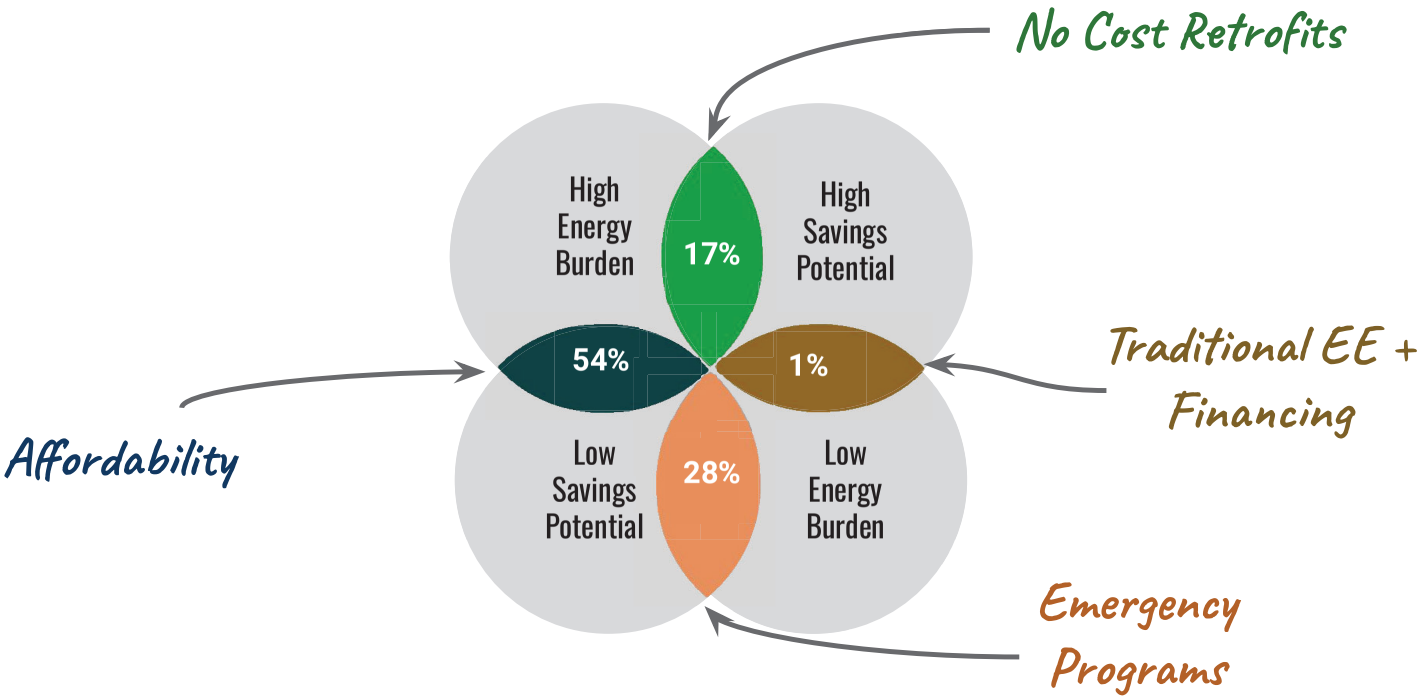
Recommendation: To capture the impact and reach of the program, track total energy assistance funding as a percent of energy assistance need as a program metric (as opposed to solely relying on participation counts)

Insights: **Rate Increase Impact (Oregon)**

2024:	Low-Income, High Burden Households **~50,000**		Existing discounts cover 49% of need Proposed discounts cover 62% of need
2025:	~54,000 (+8%)	$38.3M (+33%)	Proposed discounts cover 47% of need

*Assumes 18% average residential rate increase and 3% average household income increase in 2025

Program Potential (Oregon)



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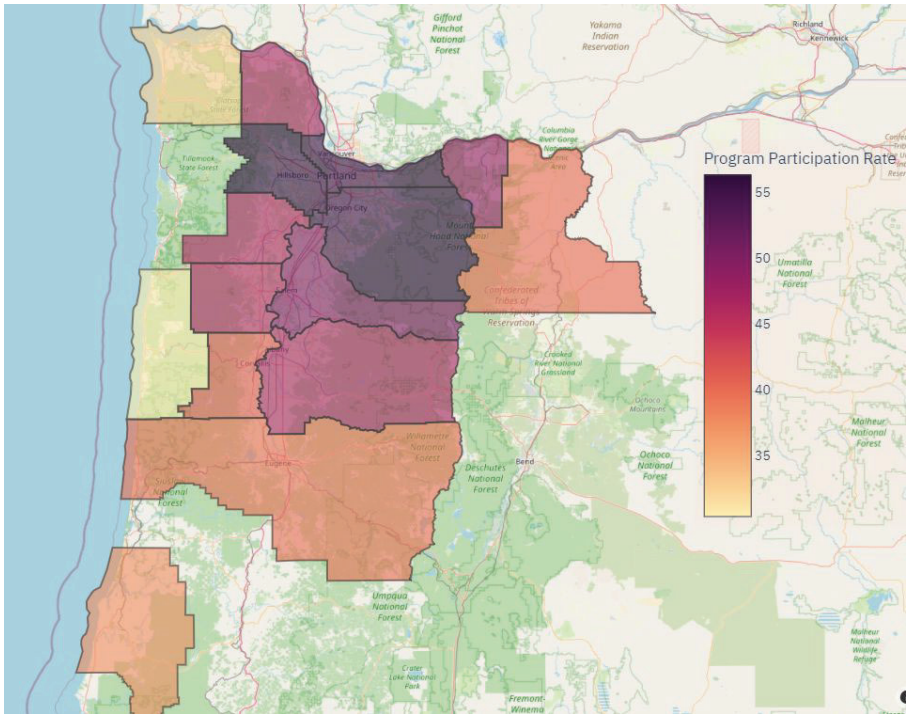
Bill Discount Program

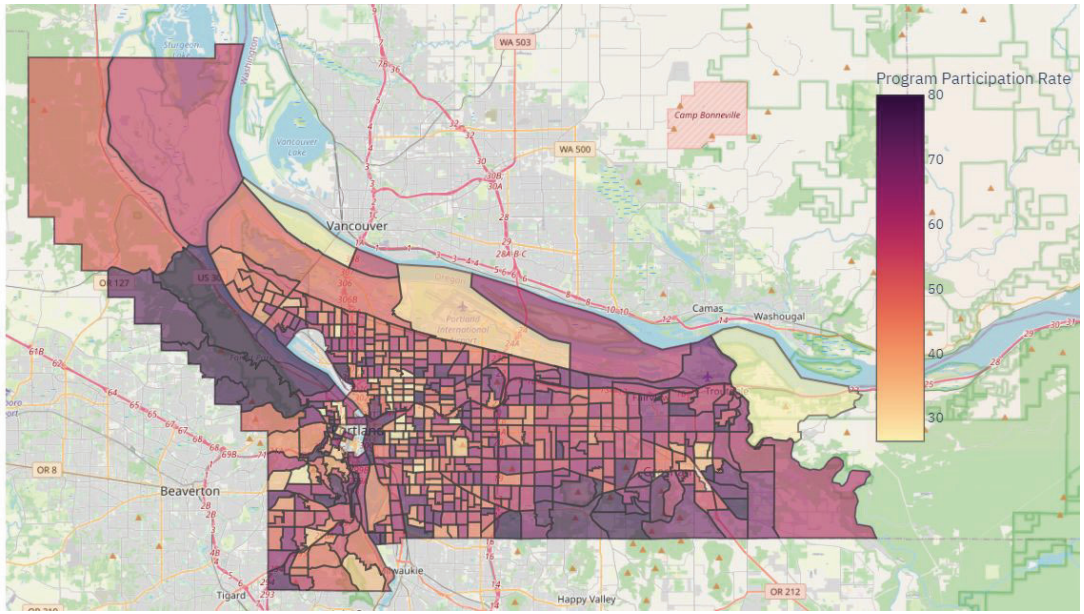
Program Participation Rate (Oregon)

Recommendation: Improve outreach in coastal and outlying areas.



Program Participation Rate (Multnomah County)

Recommendation:
Impressive participation rates in Portland area. Focus outreach on underserved neighborhoods in urban areas.



Program Saturation Rates (Oregon)

Income tier	Estimated number of households	% High-burden	Participation rate
0-15% SMI	8,000	94%	73%
15-30% SMI	17,000	89%	52%
30-45% SMI	19,000	74%	52%
45-60% SMI	27,000	50%	43%

Maintain focused outreach efforts on these groups. Target 80% participation by 2027.

Discount Tier Analysis (Oregon)

Recommendation: Assess the feasibility and benefit vs. cost of enhanced discounts for lower income tiers. This excludes interaction with other utility programs (see next slide).

Income tier	Discount Level	Discount Level (2025)	Average assistance need as a percent of bill (2024)	Average assistance need as a percent of bill (2025)
Tier 0: 0-15% SMI	40%	85%	78%	81%
Tier 1: 15-30% SMI	25%	50%	59%	63%
Tier 2: 30-45% SMI	20%	30%	40%	46%
Tier 3: 45-60% SMI	15%	15%	22%	29%

Example: Increase Tier 1 discount to 60%. Estimated budget impact at current enrollment (Q2 24): ~$1.8M (+15%)

Example: Increase Tier 2 discount to 40%. Estimated budget impact at current enrollment (Q2 24): ~$2M (+17%)

Program Interaction (Oregon)

Discount tier analyses quantify the bill reductions needed to reduce gross customer energy bills to a reasonable percentage of their income. They do not take into account other sources of energy assistance available to low-income households. This is appropriate when a utility uses the discount program as the only type of energy assistance. NW Natural also funds the Oregon Low-Income Gas Assistance (OLGA) program which provide energy assistance grants to eligible customers who apply through a community action agency.

Recommendation:

- *Option 1:* Redesign OLGA.
- *Option 2:* Sunset OLGA and shift funding to BDP.

Program Interaction (Oregon)

Recommendation:

Option 1: Redesign OLGA.

Slightly reduce 2025 proposed discount rates (50%/30%/20%/10%). Move from LIHEAP benefit matrix (fixed grant based on income tier) to bill-based credit that is an **extension of BDP** (e.g. grant for 20% of prior 12 month bills) and is intended to cover difference between BDP discount and assistance need.

Pros:

- Targets funds to customers experiencing hardship even after receiving a discount. Customers are referred to agency to apply if they are still burdened even after receiving the BDP.
- Maintains agencies as a point of application for gas assistance
- Limits over-serving customers who don't need high discounts (the higher income households within each income tier).
- Aligns OLGA with goal of energy burden reduction by tying the grant to energy usage rather than solely income

Cons:

- Complexity - maintains current structure of dual programs, cost recovery etc.
- Difficult for agencies as the redesigned program will not mirror LIHEAP anymore

Making OLGA work with BDP

Current customer journey

Enrolled in OLGA through CAPs and receive a fixed grant

↓

Autoenrolled in BDP

↓

Income tier	BDP Discount	OLGA grant
Tier 0: 0-15% SMI	85%	~$400-600
Tier 1: 15-30% SMI	50%	~$350-500
Tier 2: 30-45% SMI	30%	~$300-400
Tier 3: 45-60% SMI	15%	~$200-300

Likely overserved

Redesigned customer journey

Enrolled in **BDP first** through CAPs/NWN

↓

Customers with additional need (low income/high usage/hardship) referred to OLGA

↓

Complete OLGA application and receive additional discount as a bulk one-time bill credit

↓

Income tier	BDP Discount	OLGA grant
Tier 0: 0-15% SMI	50%	30%
Tier 1: 15-30% SMI	30%	30%
Tier 2: 30-45% SMI	20%	20%
Tier 3: 45-60% SMI	10%	20%

Program Interaction (Oregon)

Recommendation:

Option 2: Sunset OLGA.

Adopt new discount rates for 2025 (e.g. 85%/50%/30%/15%). Unify Schedules 310 and 330 (shift ~$4M to BDP).

Pros:

- Lower administrative costs ($800k per year potentially redirected to customers)
- Much smaller rate impact even with higher discounts
- Simplifies NW Natural energy assistance under one banner

Cons:

- Loses an important pathway for customer participation through the agencies.
- Worse at targeting funds to need - all customers in a tier receive the same discount for at least two years, regardless of their level of need.

Outreach Challenges

Challenge:
NW Natural's service territory has a myriad of cultures and ethnicities, a variety of economic backgrounds, urban and rural households and more. NW Natural cannot feasibly become an expert in outreach to every community within its service area.

Recommendation:

Program Navigator Fund: Incentivize local community-based organizations (CBOs) to refer and support customers in applying for the program. These CBOs would serve as the "Program Navigators" would be CBOs that register with NW Natural and would be compensated per successful customer application. Program Navigators would be trained to refer customers to other programs (e.g. LIHEAP, Energy Trust, etc.) in addition to BDP and assist with the application and post-enrolment verification process.

Pilot estimates: $200k fund, $75 per successful application. Program/pilot may be coordinated jointly with PGE/Pacific Power.

Arrearages and BDP

- NW Natural generally has a low service disconnection rate when considering unique premises (many households may get disconnected multiple times a year)
- 32% of disconnected households are reconnected on the same day and 26% reconnected within one week.
- Very few disconnected households (~100) in past year were likely eligible for energy assistance but didn't participate. **Communication about BDP to customers at risk of disconnection is working well.**

Arrearage Relief

Challenge:
About 10-15% of BDP participants enroll in the program with pre-existing arrears.

Recommendations:
While some BDP participants may need help with arrears, we are not recommending an Arrearage Management Program (AMP). In our experience, AMPs (which typically require consistent payments from customers in exchange for arrearage matching from a utility) are very onerous to implement, hard to explain to customers and typically have low success rates for customers completing the term of the program (customers do not receive the full arrearage matching because they fall behind on their bills). Most NW Natural customers have relatively small arrears. Instead, we are recommending that NW Natural provide arrearage relief using an immediate, much simpler, and no strings attached approach.

Arrearage relief for program participants: Assess the feasibility and benefit vs. cost of a capped budget arrearage relief program. For simplicity, the program should be made available to BDP participants as a retroactive credit. In other words, the customer's bill discount percent gets applied retroactively for arrears up to a limit (e.g. X% discount on first $1,000 of arrears).

Pilot estimate: $500k arrearage relief fund is likely sufficient to serve the 3,000-4,000 BDP customers who enroll with pre-existing arrears.

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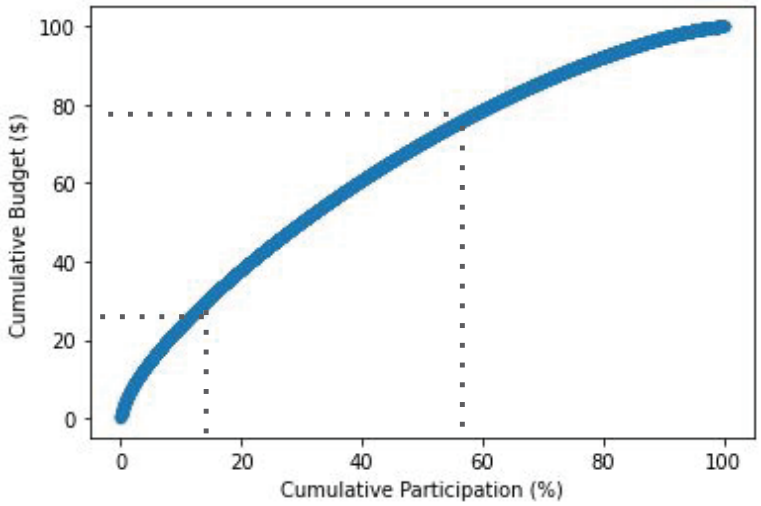
Energy Efficiency

Bill Discount Program utilization



Within each income/discount tier:

Top 10% of participants by energy use utilize 21-24% of budget. Their average energy use is 80% higher than the overall average energy use.

Top 50% of participants by energy use utilize 69-72% of budget. Their average energy use is 30% more than the overall average energy use.

Top 10 energy users will receive $3,000+ in 2025

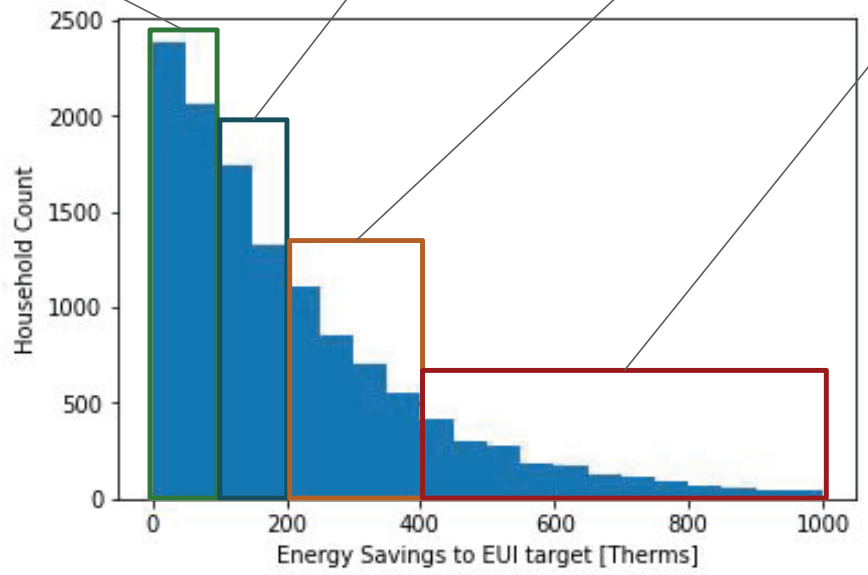
Energy Efficiency Potential (Oregon) (12,500 low-income households)

35% Smart thermostats, pipe insulation, furnace tuneups

24% HE water heater/furnace

25% Weatherization

16% Custom / Energy Audits



EUI target = 0.6 Therms/sq.ft

Energy Efficiency Potential

Challenge:
Overall, energy efficiency potential appears to be concentrated in a small segment of low-income customers. High energy users overutilize program funds while the root cause of their high energy burden remains unaddressed. There are 12,000 low-income customers (7,400 BDP participants) who would potentially be good candidates for energy efficiency measures, but existing low-income EE programs serve relatively few households.

Recommendations:

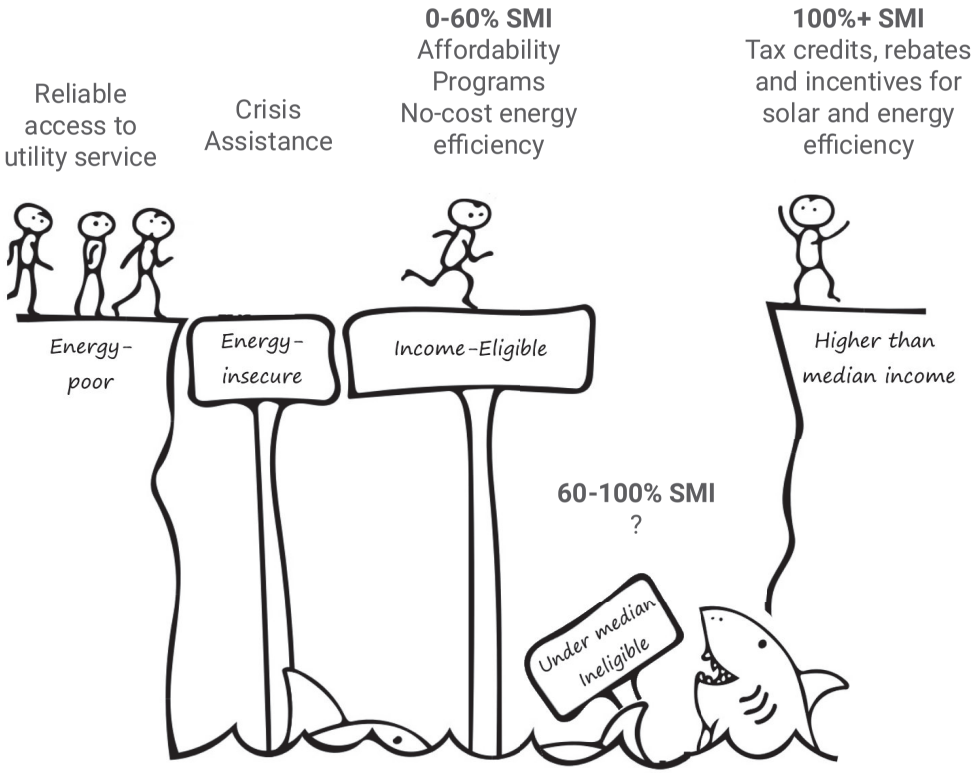
First step towards integrating energy efficiency with BDP is to identify and understand the high use participants.

Energy audit program: Establish a energy audit pilot program (through RFP) that focuses on the top 2,000 or so users in BDP ($1.5M approx. budget). Program should include walkthrough energy audit, ETO and EE credit referrals. List of high priority homes should be provided to program implementer. This program can be designed to be cost-effective through realized savings in BDP discounts.

Unbundled energy efficiency: 35-40% of households could have their energy use reduced to a reasonable level through low-cost measures, without requiring extensive weatherization. Evaluate the feasibility of funding or offering low-cost measures (smart thermostats, pipe insulation, furnace tuneups) and energy education at no-cost to low-income households. This would be most effectively accomplished in collaboration with the Energy Trust of Oregon

The Energy Assistance Hole

The Energy Assistance Hole



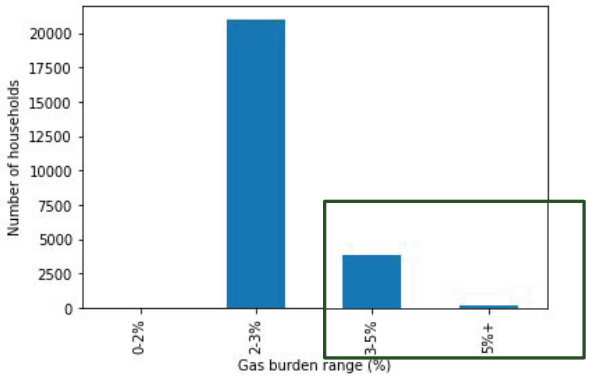
The Energy Assistance Hole (Oregon)

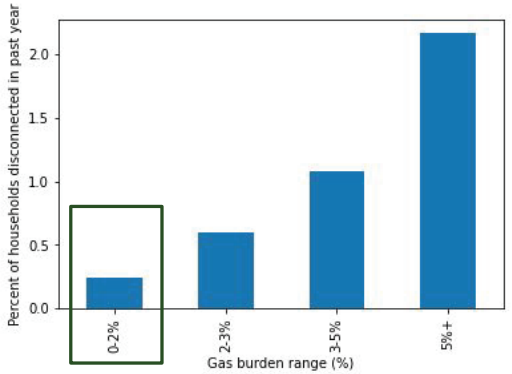
~4k non-low-income households with a high energy burden >3%

~21k borderline (2-3% burden)

Moderate income, high gas use (1,200 Therms/yr on average)

~1k non-low-income households at risk of disconnection despite having a low energy burden





Addressing high-burden, program-ineligible households

Challenge:
There are households that are not eligible for existing programs but may need help improving their bill affordability.

This includes households that:

- Are under the state median income, have a high energy burden, but are ineligible for assistance
- Constrain their energy use due to lack of affordability and lack of program access
- Are **A**sset **L**imited, **I**ncome **C**onstrained, **E**mployed
- Earn above the program income thresholds but under the Self Sufficiency Standard Income

Recommendations:

Customers in this category are high gas users, so discounts and grants do not solve the root causes of their high burden.

Offer no-cost energy weatherization: Expand eligibility for OLIEE to 80% SMI in 2025 and potentially up to 100% SMI in future years

Coordination with energy efficiency providers: Work with ETO and CAP agencies to target EE funds at low-income, high burden households. Consider targeted co-marketing campaigns based on data from this assessment.

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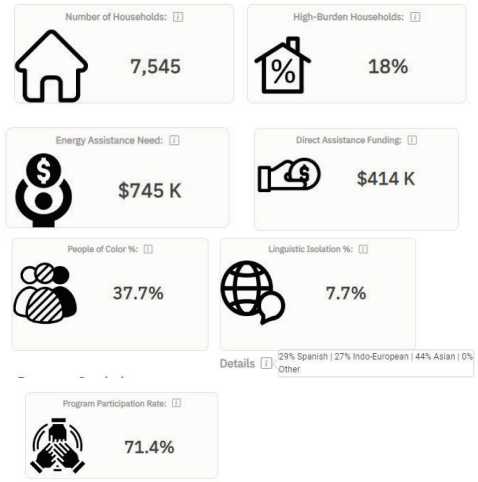
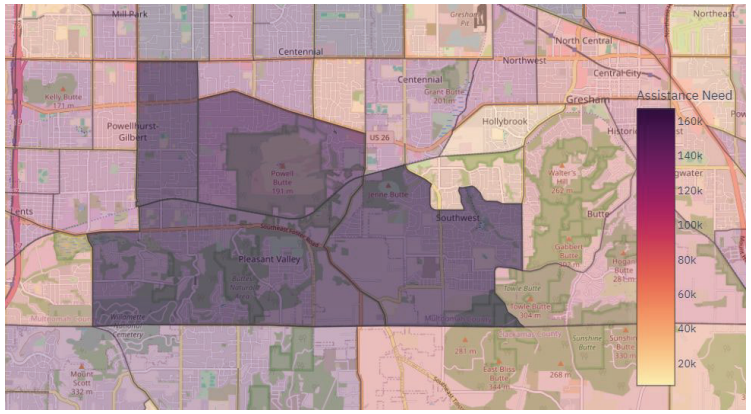
Community Profiles

Pleasant Valley (Multnomah County)

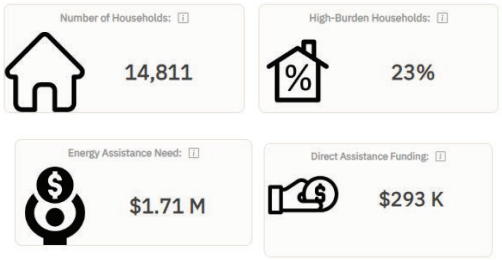
41051008901, 41051009000, 41051009102, 41051009903



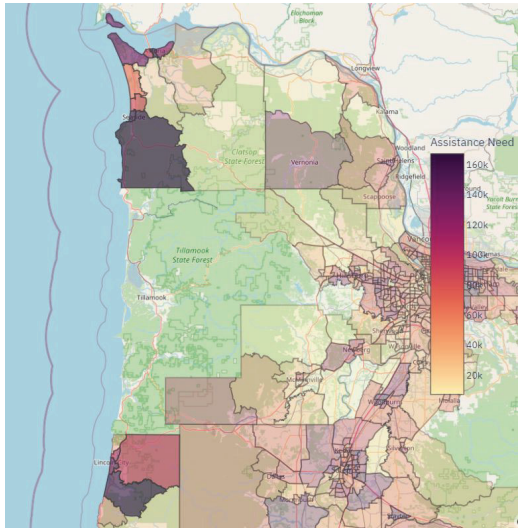


- Diverse community
- Very high participation rates

Coastal Areas (Clatsop/Lincoln)



- Small town communities
- High level of burden
- Underserved by discounts/LIHEAP



Tracts:
41007950100
41007950200
41007950300
41007950500
41007950700
41007950900
41007951100
41007951300
41041950100
41041950304
41041950400
41041950601

Other Recommendations

Post-enrolment verification

Challenge:
BDP was designed with self-declared income and the intent was to establish a post-enrolment verification process for 3% of participants in a random draw.

Recommendations:

Targeted verifications: Consider a more targeted verification protocol. Consult with BDP advisory group to determine criteria for initiating a verification (e.g. high property value, own multiple properties, high estimated income).

Potentially use remunerated program navigators to assist customers with responding to the verification request.

Rough estimates of PEV counts

Risk-based: 2,500 (7%) High value homes - 1,100 (3%) of which are in high discount tiers

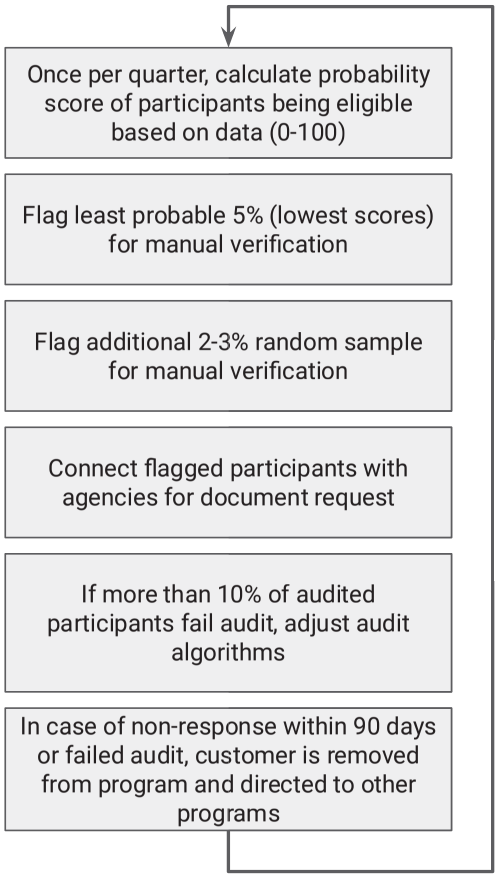
Benefit value-based: 1,700 (5%) receiving over $1,000 from BDP

Audit Protocol for Self-Verification and Auto-Enrollment

The audit process and scoring algorithms are developed and operated within the utility - customer audit lists are shared with agencies.

Data requirements:

- Home values
- Housing type
- Renter/homeowner
- Disconnect/past due notices
- Home location and average neighborhood energy burden
- Participation in other means-tested benefits (optional)
- Estimated customer income range (optional)



Continuous monitoring of audit metrics (esp. equity of audits and failure rates) and iterative improvement of scoring algorithms

Other Issues

Reduce need for reapplication: Allow fixed income customers to reapply every 4-5 years instead of every two.

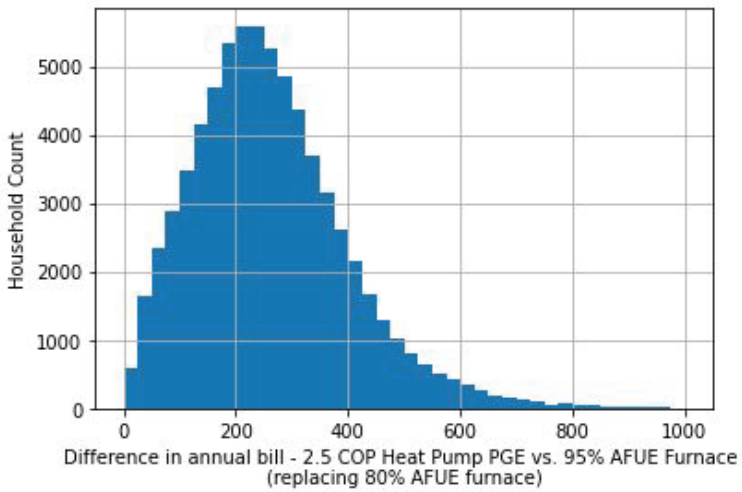
Communication timing: Biggest marketing pushes should be in September/October **before** high bill season. Include communication about projected winter bills including rate increases and energy efficiency tips to encourage customers to apply early.

Rate design: Evaluate raising the fixed charge with a corresponding decrease in the therm charge. The fixed charge also does not reflect NW Natural's true fixed costs (average of $34 for the residential class). This encourages conservation and solar but low-income customers cannot afford these improvements. Higher volumetric rates are a major trigger for falling behind on bills when a customer receives an unplanned bill during the cold season.

Enrolment target: Use energy assistance need in addition to enrolment as a program metric. Participation rates alone do not reflect whether the program is alleviating energy burden. Set program targets in relation to energy assistance need (similar to Washington state) as opposed to enrolment % targets - this incentivizes targeting the highest need customers vs. just a higher number of participants.

Master-metered buildings

Electrification burden through OLIEE



Assumptions:

- 80% of gas usage is for heating
- 80% AFUE gas furnace as baseline
- Cost comparison for a 3 ton central heat pump (2.5 average COP) vs 95% AFUE gas furnace
- Chart is for LI households in Oregon, assuming PGE electric rates
- Not including additional cooling costs

Main Takeaways - Energy Burden Assessment

- NW Natural's customers are relatively higher income and live in a moderate climate. This is reflected in a generally moderate gas burden. Approximately **9% of NW Natural's customers suffer from a high gas burden** (exceeding 2/3% depending on the climate zone)
- The Bill Discount Program (BDP) has been ramping up successfully and along with other assistance programs, is expected to meet **49% of the energy assistance need** for NW Natural's customers in 2024 and 47% of the need in 2025 (including rate increases and proposed discount tiers).
- Recommendations in this assessment are auxiliary components that can be added to NW Natural's energy assistance portfolio to better improve bill affordability:
    - **BDP:** How to deal with the interaction between BDP and OLGA/GREAT to eliminate participants' high energy burden
    - **Arrearages:** How to best serve customers with pre-existing arrears
    - **Energy Efficiency:** How can we leverage energy efficiency for sustained energy burden reduction
    - **Energy assistance hole:** How to best serve customers who have unaffordable bills but are ineligible for assistance programs
    - **Other:** How do we design more equitable rates and target assistance at customers who need it the most

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NW Natural

2024 Energy Burden Assessment

Summary of Recommendations

empower dataworks

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Summary of Recommendations

	Recommendation	Cost/Complexity	Impact/Priority	Timeline
BDP	Track energy assistance funding percent as a BDP evaluation metric	Low	Low	2025
	Focus immediate BDP outreach efforts on 0-30% SMI households	Medium	Medium	Q4 2024
	Re-examine OLGA/GREAT in context of the BDP and consider redesigning or sunsetting those programs	High	High	Q4 2024
	Assess impact of enhanced discounts for lower income tiers, as well as hybrid discount/grant model	High	High	Q4 2024
	Allow fixed income customers to reapply every 4-5 years instead of every two	Low	Low	2025
	Implement a targeted post-enrolment verification protocol	Low	Medium	2025
Program Portfolio	Assess impact of retroactive application of bill discount for customers in arrears (arrearage forgiveness)	Low	Medium	2025
	Biggest marketing pushes should be before high bill season	Low	Low	2025-27
	Initiate a Program Navigator fund for partner nonprofits to help customers access programs	Medium	Medium	2025
	Expand eligibility for OLIEE to 80% SMI and potentially up to 100% SMI in future years	Low	Low	2025
	Consider an energy audit program for high users in energy assistance programs	Medium	High	2025
	Allocate energy efficiency funding for unbundled measures through ETO for low-income, high-burden customers	High	High	2026+
Other	Consult with advisory groups on potential solutions to help households under state median income but above energy assistance income thresholds	Medium	Low	2025
	Adjust timing of rate increases	Low	Medium	2025
	Consider revisiting fixed charge component of residential rate schedule	Medium	Medium	Next GRC

Insights: **High-level Assistance Gap (Oregon)**

Low-Income, High Burden Households

~50,000

Income-eligible only

2024 Projection not including additional program participation.
Bill Discount Program (BDP): ~$8.3M

2025: $12M BDP, $18M total - 62% of need

➔ At program maturity (year 5+), best practice is to target at least 60-70% of the need available as program funding - with proposed 2025 rates, BDP would need additional participation. Once this target is reached, participation usually slows down and focus shifts to program optimization and targeted outreach.

Recommendation: To capture the impact and reach of the program, track total energy assistance funding as a percent of energy assistance need as a program metric (as opposed to solely relying on participation counts)

Program Saturation Rates (Oregon)

Income tier	Estimated number of households	% High-burden	Participation rate
0-15% SMI	8,000	94%	73%
15-30% SMI	17,000	89%	52%
30-45% SMI	19,000	74%	52%
45-60% SMI	27,000	50%	43%

Maintain focused outreach efforts on these groups. Target 80% participation by 2027.

Discount Tier Analysis (Oregon)

Recommendation: Assess the feasibility and benefit vs. cost of enhanced discounts for lower income tiers. This excludes interaction with other utility programs (see next slide).

Income tier	Discount Level	Discount Level (2025)	Average assistance need as a percent of bill (2024)	Average assistance need as a percent of bill (2025)
Tier 0: 0-15% SMI	40%	85%	78%	81%
Tier 1: 15-30% SMI	25%	50%	59%	63%
Tier 2: 30-45% SMI	20%	30%	40%	46%
Tier 3: 45-60% SMI	15%	15%	22%	29%

Example: Increase Tier 1 discount to 60%. Estimated budget impact at current enrollment (Q2 24): ~$1.8M (+15%)

Example: Increase Tier 2 discount to 40%. Estimated budget impact at current enrollment (Q2 24): ~$2M (+17%)

Program Interaction (Oregon)

Discount tier analyses quantify the bill reductions needed to reduce gross customer energy bills to a reasonable percentage of their income. They do not take into account other sources of energy assistance available to low-income households. This is appropriate when a utility uses the discount program as the only type of energy assistance. NW Natural also funds the Oregon Low-Income Gas Assistance (OLGA) program which provide energy assistance grants to eligible customers who apply through a community action agency.

Recommendation:

- *Option 1:* Redesign OLGA.
- *Option 2:* Sunset OLGA and shift funding to BDP.

Program Interaction (Oregon)

Recommendation:

Option 1: Redesign OLGA.

Slightly reduce 2025 proposed discount rates (50%/30%/20%/10%). Move from LIHEAP benefit matrix (fixed grant based on income tier) to bill-based credit that is an **extension of BDP** (e.g. grant for 20% of prior 12 month bills) and is intended to cover difference between BDP discount and assistance need.

Pros:

- Targets funds to customers experiencing hardship even after receiving a discount. Customers are referred to agency to apply if they are still burdened even after receiving the BDP.
- Maintains agencies as a point of application for gas assistance
- Limits over-serving customers who don't need high discounts (the higher income households within each income tier).
- Aligns OLGA with goal of energy burden reduction by tying the grant to energy usage rather than solely income

Cons:

- Complexity - maintains current structure of dual programs, cost recovery etc.
- Difficult for agencies as the redesigned program will not mirror LIHEAP anymore

Making OLGA work with BDP

Current customer journey

Enrolled in OLGA through CAPs and receive a fixed grant

↓

Autoenrolled in BDP

↓

Income tier	BDP Discount	OLGA grant
Tier 0: 0-15% SMI	80%	~$400-600
Tier 1: 15-30% SMI	40%	~$350-500
Tier 2: 30-45% SMI	20%	~$300-400
Tier 3: 45-60% SMI	15%	~$200-300

Likely overserved

Redesigned customer journey

Enrolled in **BDP first** through CAPs/NWN

↓

Customers with additional need (low income/high usage/hardship) referred to OLGA

↓

Complete OLGA application and receive additional discount as a bulk one-time bill credit

↓

Income tier	BDP Discount	OLGA grant
Tier 0: 0-15% SMI	50%	30%
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Tier 2: 30-45% SMI	20%	20%
Tier 3: 45-60% SMI	10%	20%

Program Interaction (Oregon)

Recommendation:

Option 2: Sunset OLGA.

Adopt new discount rates for 2025 (85%/50%/30%/25%). Unify Schedules 310 and 330 (shift ~$4M to BDP).

Pros:

- Lower administrative costs ($800k per year potentially redirected to customers)
- Much smaller rate impact even with higher discounts
- Simplifies NW Natural energy assistance under one banner

Cons:

- Loses an important pathway for customer participation through the agencies.
- Worse at targeting funds to need - all customers in a tier receive the same discount for at least two years, regardless of their level of need.

Outreach Challenges

Challenge:
NW Natural's service territory has a myriad of cultures and ethnicities, a variety of economic backgrounds, urban and rural households and more. NW Natural cannot feasibly become an expert in outreach to every community within its service area.

Recommendation:

Program Navigator Fund: Incentivize local community-based organizations (CBOs) to refer and support customers in applying for the program. These CBOs would serve as the "Program Navigators" would be CBOs that register with NW Natural and would be compensated per successful customer application. Program Navigators would be trained to refer customers to other programs (e.g. LIHEAP, Energy Trust, etc.) in addition to BDP and assist with the application and post-enrolment verification process.

Pilot estimates: $200k fund, $75 per successful application. Program/pilot may be coordinated jointly with other utilities.

Arrearage Relief

Challenge:
About 10-15% of BDP participants enroll in the program with pre-existing arrears.

Recommendations:
While some BDP participants may need help with arrears, we are not recommending an Arrearage Management Program (AMP). In our experience, AMPs (which typically require consistent payments from customers in exchange for arrearage matching from a utility) are very onerous to implement, hard to explain to customers and typically have low success rates for customers completing the term of the program (customers do not receive the full arrearage matching because they fall behind on their bills). Most NW Natural customers have relatively small arrears. Instead, we are recommending that NW Natural provide arrearage relief using an immediate, much simpler, and no strings attached approach.

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Master-metered buildings

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The Chilling Effect of Trump's Indiscriminate Immigration Arrests & Propaganda

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Published: February 14, 2025

Author: Nayna Gupta

Topics: Abuses, Border Enforcement, Interior Enforcement

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American Immigration Council

The American Immigration Council is a non-profit, non-partisan organization. ***Sign up to receive our latest analysis as soon as it's published.***

As we near the one-month mark of the new Trump administration, it is clear that the president's thinly veiled threats of imposing mass deportation on "criminal immigrants" are in fact a promise to target all immigrants—and sometimes even U.S. citizens.

In the first weeks, we have already seen **wrongful immigration arrests of people with U.S. passports**, including a **veteran in New Jersey**, **Native Americans** in the Navajo nation, and others from Puerto Rico. We have reports of the sweeping-in of immigrants with lawful status who pose absolutely no public safety threat, including **Venezuelan people with no criminal record**, shipped off to Guantanamo Bay. A **mi middle-school teacher with DACA** faced arrest and possible deportation.

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American Immigration Council

The consequence of a mass deportation agenda that targets anyone and everyone is a chilling effect. The threat itself of aggressive immigration enforcement imposes fear on immigrant and minority communities. They become scared to leave the house, go to work, or attend school as these everyday activities could end in detention and deportation of themselves or their loved ones. School districts like one in Texas, are **forced to send letters** to their students and parents, warning them that ICE may show up on the morning school bus. And when ICE uses intimidation stunts like posting ominous photos of alleged "criminal immigrants," publicizes its raids, or uses military planes to deport people, the fear mongering becomes theater but also hurts local communities and their economies.

Citrus farmers in California were afraid to show up to work, just like farmers in Florida, New York and Iowa. When ICE threatened enforcement in Chicago, some people **hid in their attics.** In states like Texas, where undocumented people represent approximately 50% of the construction industry's labor force–this chilling effect will have reverberations for local housing costs and economies. This is unsurprising considering that the 11 million undocumented people who live in the U.S. fill critical sectors of the labor market–like agriculture, construction, and health care–in addition to loving U.S. citizen children and partners and having deep ties to our communities.

It doesn't matter whether ICE hits its arrest "quotas" or "targets," the damage is already at play. President Trump has set a goal of approximately 1,000 arrests per day for immigration enforcement agencies–a goal his administration was unable to meet this past week. But using immigration enforcement to score political points and adopting a terrorizing PR strategy means people still won't show up for our country and economy–and that hurts all of us.

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American Immigration Council

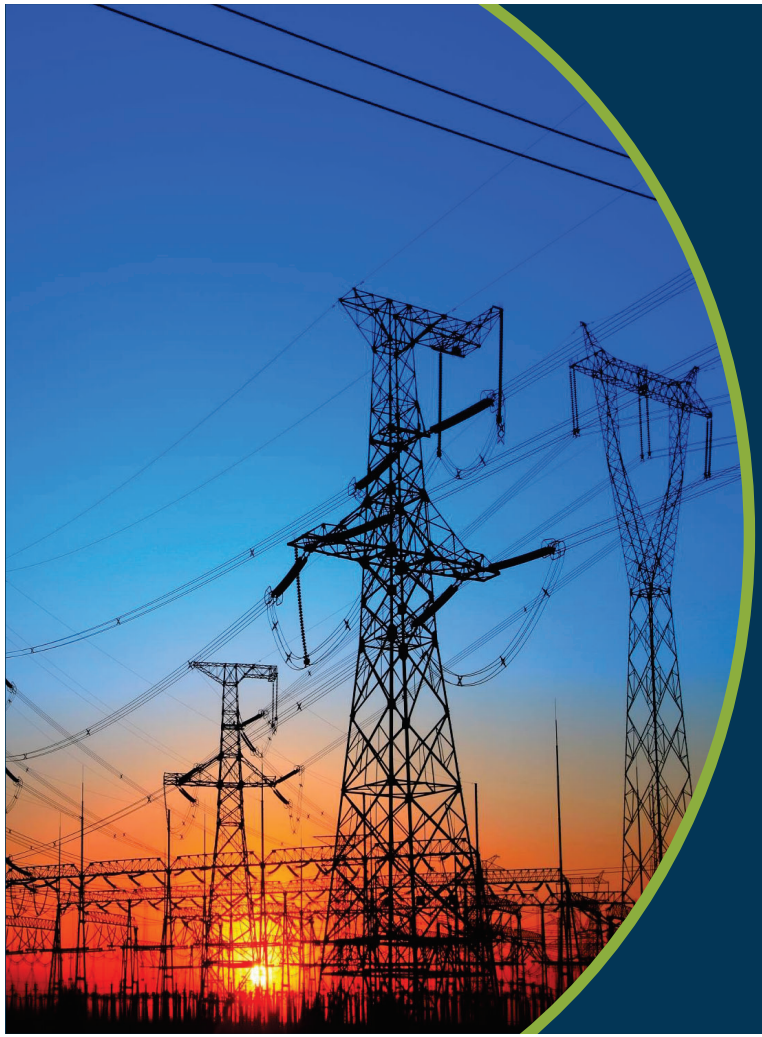
additional $3,745.

To meet these costs, President Trump has redirected law enforcement resources away from critical priorities like combating drug trafficking, terrorism, and child sex crimes to instead focus on arresting and deporting people who pose no threat at all. For example, **Trump ordered** ICE's Homeland Security Investigations (HSI), which typically investigates online child sex abuse material and fights transnational criminal organizations, to make it their "primary mission" instead to investigate immigration law offenses. We have seen this redirection of critical public safety resources before. During Trump's Zero Tolerance policy in 2018—which led to family separations at the border—prosecutors had to drop other cases to focus on charging migrants with misdemeanors. As a result, **prosecutions for drug trafficking** at the border plummeted.

Now, as President Trump signals that he sees ICE's arrests as **too low** in number and frequency, he is working with Congress to seek $175 to $200 billion additional dollars to fuel this mass deportation agenda. This request is six times more than the already historically-high funding levels of around $30 billion for ICE and CBP. We can be assured that if Congress approves these unprecedented dollars, indiscriminate arrests of U.S. citizens and people who pose no public safety threat will continue at the expense of safety and security.

Donald Trump Immigration and Customs Enforcement

Trump Administration



Oregon Public Utility Commission

Ratemaking Framework

Workshop #3: Existing Regulatory Structures

Friday, February 27, 2026
1:30-4:00 pm PT

Meet the GPI Facilitation Team

Aileen Cole
Manager

Trevor Drake
VP, Energy Systems

Val Stori
Senior Policy Manager

Benjamin Stafford
Senior Policy Manager

Audrey Negro
Meeting & Administrative Associate

Hallie Turner
Policy Associate

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The Great Plains Institute is an organization of leaders and experts dedicated to engaging and collaborating with people, organizations, and communities to craft nonpartisan, pragmatic energy solutions that benefit people, the economy, and the environment.

UG 527/CUB/113
Wochele-Jenks/3

Agenda

1:30	Welcome and Introductions
1:40	**Staff Presentation:** Overview of Written Comments and Current Regulatory Landscape
2:05	**Presentation from Pacific Northwest National Laboratory (PNNL):** Oregon's Existing Utility Rates and Related Mechanisms
2:45	**BREAK**
3:00	**Breakout Discussions**: Evaluating Oregon's Current Ratemaking Framework
3:45	Breakout Room Takeaways and Whole-Group Discussion
3:55	Next Steps and Wrap-Up
4:00	Adjourn

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Meeting Ground Rules

1. Respect differences of perspective and the time we have together.
2. Be open to continued learning and growth informed by new information; it is ok for perspectives to shift or change throughout the process.

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Meeting Objectives

1. Develop a shared understanding of Oregon's current ratemaking framework.
2. Discuss aspects of the current framework that are working well and high impact opportunities to enhance our approach.

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AR 676 Phase 1 Workshop Schedule

Date	Workshop	
December 17, 2025	**Kickoff Meeting**	• Review objectives and process • Presentation of MYP report • Presentation of survey results
January 27, 2026	**PBR Foundations**	• Stakeholder input on goals/outcomes approach • Review common PBR mechanisms • Facilitated discussion
February 27, 2026	**Existing Regulatory Structures**	• Review current regulatory structures in Oregon to clarify leverage points for incentive alignment • Facilitated discussion
Early April 2026	**Exploration of MYP and PBR Design for Oregon**	• Participants provide input on MYP design elements and preferred PBR mechanisms • Facilitated discussion
May 2026	• Staff to file report outlining foundational concepts, goals, and outcomes (Phase 1 items) for MYPs in Oregon • Staff to present report findings at Public Meeting	

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Presentation Whiteboard Activity

During the presentations, participants are encouraged to add their thoughts and responses to the following two questions via the shared whiteboard:

1. What aspects of Oregon's existing ratemaking framework do you think are working well?
2. What aspects of Oregon's existing ratemaking framework do you think could be adjusted or evolved as part of this process?

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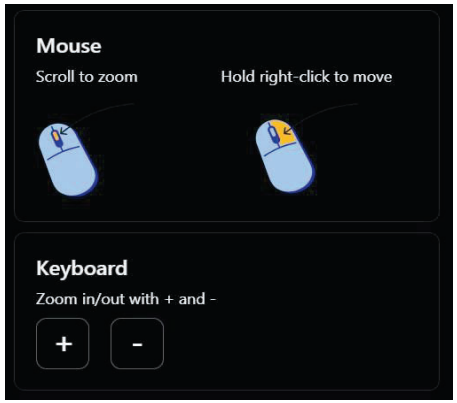
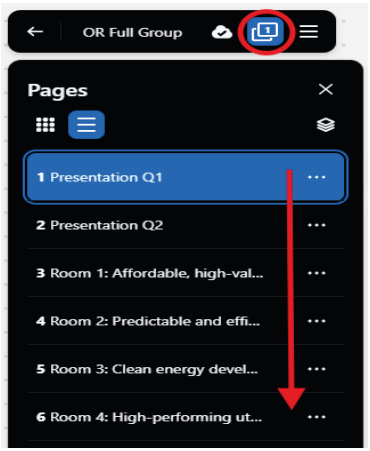
Whiteboard "How To"

- In the bottom right corner, select the hand to move around the whiteboard.

- To place a sticky note, hover over a sticky note stack and click. Move your cursor to where you would like to place the sticky note and click again.



- You may also use your mouse (right click) and keyboard to navigate the whiteboard.



- Whiteboards can have multiple pages. In the upper left corner, select the page icon to open the page navigation bar.

AR 676 Workshop #3
Staff Overview

Stephanie Andrus (DOJ)
Michelle Scala
Bret Stevens

Oregon Public Utility Commission

February 27, 2026

Relevant statutes – Ratemaking

ORS 756.040

- Rates must provide adequate revenue to cover a utility's operating expenses and capital costs
- Rates must allow the utility to earn a return that is commensurate with the return on investments in other enterprises having corresponding risks
- Rates must be sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital

ORS 757.355

- Prohibits recovery in rates for facilities not currently used for providing service ("used and useful")

ORS 757.259

- Authorizes retroactive ratemaking in only limited circumstances

Relevant statutes – Ratemaking

ORS 757.612

- Requires electric companies to surcharge customers a statutorily required amount for the purpose of establishing a public purpose fund

ORS 757.269

- Specific requirements related to recovery of tax expense and deferred tax credits

ORS 757.205, et seq.,

- Establish several procedural requirements related to rate-setting
- Do not authorize any party other than a utility to file a tariff

Relevant statutes – Performance Based Rates

ORS 757.210

- Electric and gas utilities can request an alternative form of regulation (AFOR)
- Defines an AFOR as a plan adopted by the commission *upon petition by a public utility*
- Defines AFOR as a plan that sets rates and revenues and a method for changes in rates and revenues using alternatives to cost-of-service rate regulation

ORS 757.603

- Electric company shall provide all retail electricity consumers that are connected to the electric company's distribution system with a regulated, cost-of-service rate option

Relevant statutes – Performance Based Rates

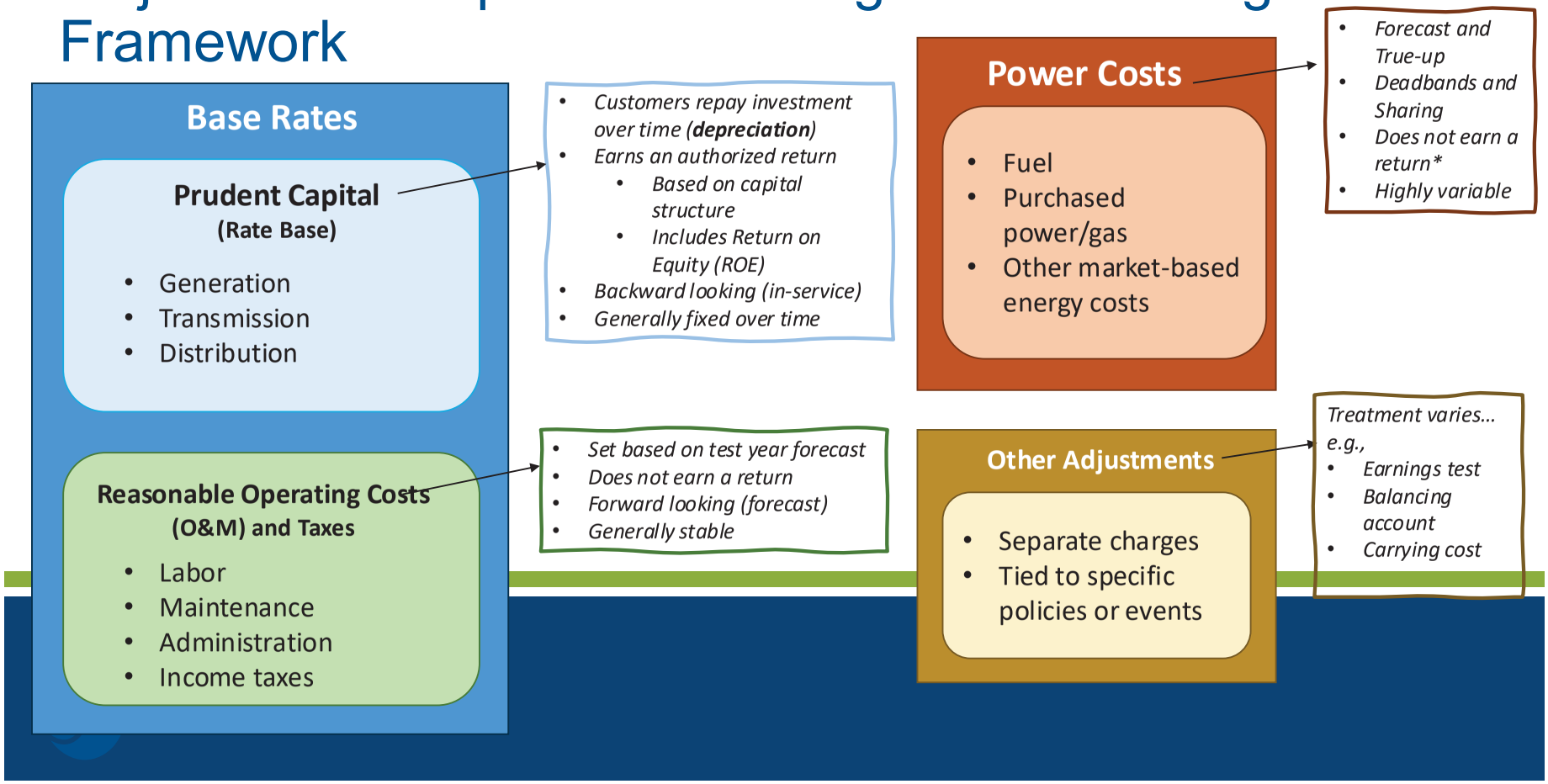
ORS 757.217

- Requires the Commission to adopt rules requiring natural gas and electric utilities to establish multi-year rate plans
- Gives the Commission discretion to *provide incentives* for efficient utility operations

ORS 757.046

- Authorizes the Commission to impose performance-based rates, with incentives and penalties, on *electric utilities* to achieve regulatory objectives listed in the statute

Major Cost Components in Oregon Ratemaking Framework



Stakeholder Comments Overview:
Identified strengths of Oregon's current structure

perspectives vary

- Power and gas cost adjustment mechanisms already mitigate a significant share of cost volatility.
- Earnings tests ensure that customers are sharing in cost savings.
- Commission oversight remains active and iterative through frequent proceedings.
- Adjustment clauses and capital trackers have reduced regulatory lag for large cost categories.

Stakeholder Comments Overview:
Areas to discuss further

- Clarifying which revenue risks remain with utilities versus automatic revenue adjustments
- Determining whether the MRP would consolidate existing trackers and deferrals or layer on top of them.
- Calibrating earnings sharing and performance incentives so they are financially meaningful but bounded.
- Defining guardrails if earnings drift outside an authorized range.
- Establishing clearer criteria for reopeners during stay-out periods.
- Clarifying how affordability would be operationalized before tying it to incentives.
- Considering whether design elements differ between gas and electric utilities.

Stakeholder Comments Overview:
Recurring structural design decision points

- The scope of costs included inside the MRP (particularly capital and O&M categories).
- The length and structure of the stay-out period and its reopener triggers.
- The degree of automatic revenue adjustment versus Commission review.
- The strength and symmetry of earnings sharing mechanisms.
- Whether performance incentives begin with financial exposure or a test phase.
- Whether capital recovery structures remain unchanged or are modified.

Ratemaking Framework Scope: Phases 1-2

Foundational Design Elements	• Plan duration (3-7 years) • Type of MRP (index-based, forecasted, hybrid) • Scope of an MRP (limited or comprehensive) • Goals-outcomes hierarchy
Revenue Mechanisms and Adjustments*	• ROE • Going-in (year 1) rates • Annual adjustments: inflation, productivity, exogenous event treatment, consumer dividend • Treatment of capital expenses
Additional Elements	• Performance measures (PIMs) and metrics • Shared savings mechanisms and earnings sharing mechanism • Off-ramps and re-openers
Transition to the next MRP	• Rebasing process • Efficiency carryover mechanism

* Phase 2 may determine which mechanisms are used while values would be determined in a rate case or other docket

Current Alternative Ratemaking Mechanisms

Cost Control	Service Quality	Risk Allocation	Capital Trackers
• Sharing Mechanisms • Earnings Test	• Vegetation PBR	• Decoupling • PCAM • PGA	• RAC • ARM

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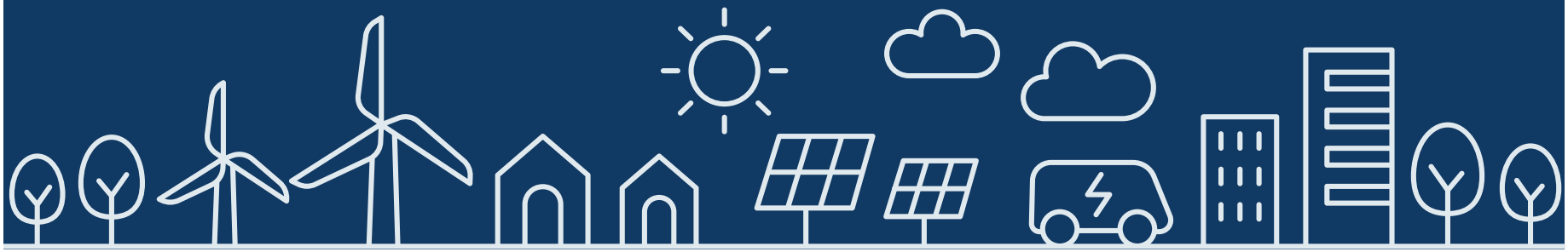
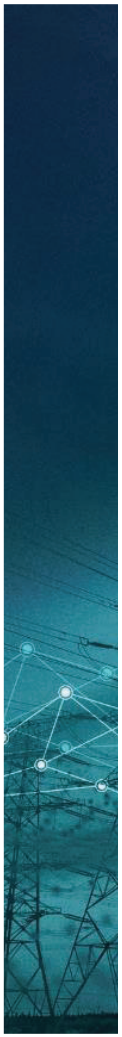
Clarifying Questions





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Oregon's Existing Utility Rates and Related Mechanisms

Jessica Shipley, Sarah Barrows, and Jason Eisdorfer

February 27, 2026

PNNL-SA-220303

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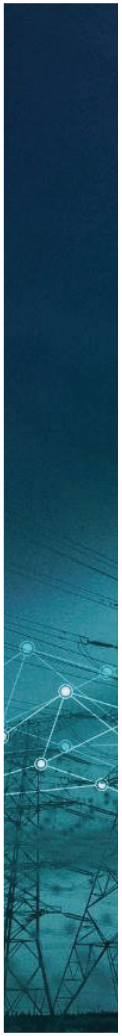

Acknowledgement

The technical assistance activity that produced this resource was funded by the U.S. Department of Energy's: Office of Critical Minerals and Energy Innovation; Office of Cybersecurity, Energy Security, and Emergency Response; and Office of Electricity. The authors are solely responsible for any omissions or errors contained herein.

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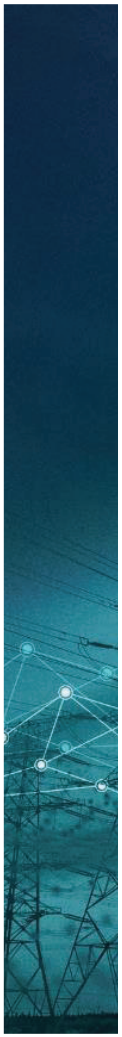
Scope of this Presentation

- Trends in the frequency of rate cases and other rate schedule filings
- Primary cost components of Oregon gas and electric revenue requirements and bills
- Basic overview of how rates are set
- Forecasted or proposed costs
- Existing cost-sharing mechanisms

- For reference, a slide map and key terms are provided in the appendix. Throughout the presentation, key terms are highlighted in blue.



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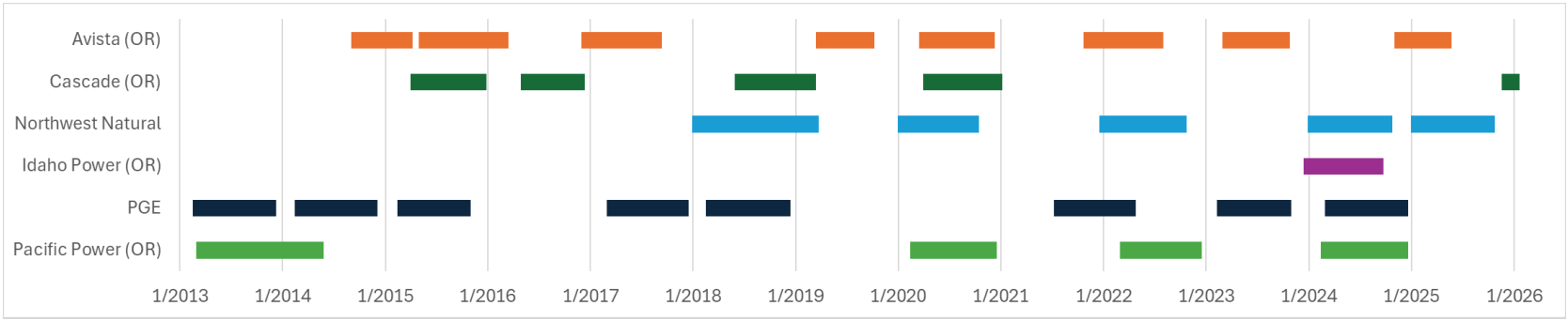
Summary

- Rate case frequency is variable across utilities and over the last decade, but there are time periods when rate case filings are nearly annual.
- Between rate cases, power/gas costs and true-ups occur annually, plus updates to a multitude of other schedules, adders, and automatic adjustment clauses.
- "Single issue" requests for revenue requirement adjustments are a more recent occurrence.
- Structure of authorized revenue for PGE and PacifiCorp is similar:
  - Adders / supplemental schedules: 5-8%
  - Base rates: ~60%
  - Power costs: ~33%
- For Avista and Northwest Natural, the percentage ranges are a bit larger:
  - Adders / supplemental schedules: 8-12%
  - Base rates: 58-66%
  - Gas costs: 22-34%
- IRPs and electric utility representations indicate a new cycle of very large generation and transmission capital investments over the next 3 to 6 years.
- IRPs for natural gas utilities are exploring flat or reduced load over 20 to 30 years in part due to state policies.

Rate Case Timeline: Filing Date to Order Date



Source: PNNL compilation from dockets UE 433, UE 399, UE 374, UE 263, UE 435, UE 416, UE 394, UE 335, UE 319, UE 294, UE 283, UE 262, UE 426, UG 520, UG 490, UG 435, UG 388, UG 344, UG 525, UG 390, UG 347, UG 305, UG 287, UG 519, UG 461, UG 433, UG 389, UG 366, UG 325, UG 288, and UG 284

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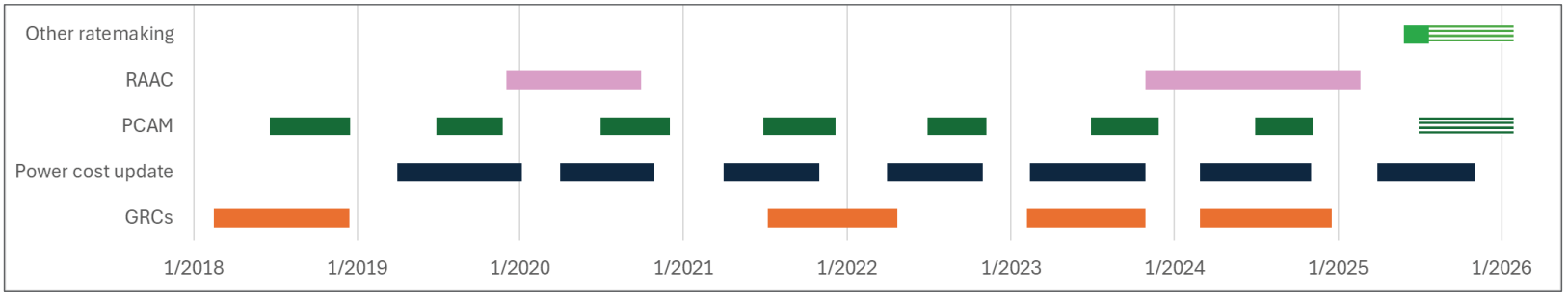
Electric Utilities

Ratemaking-Related Proceedings Timeline

(Illustrative and not exhaustive)

Portland General Electric proceedings used as an illustration:



: docket or proceeding(s) not yet complete

"Other ratemaking": Overlapping proceedings addressing an application for a distribution system plan alternative rate mechanism, and a request for Seaside battery storage alternative rate mechanism

Other schedules not shown here: See next slide for a focus on 2022 – 2024.

Source for this slide and next: PNNL compilation from dockets UE 435, UE 416, UE 394, UE 335, UE 319, UE 294, UE 283, UE 262, UE 427, UE 372, UE 370, UE 459, UE 455, plus power cost update and PCAM dockets.

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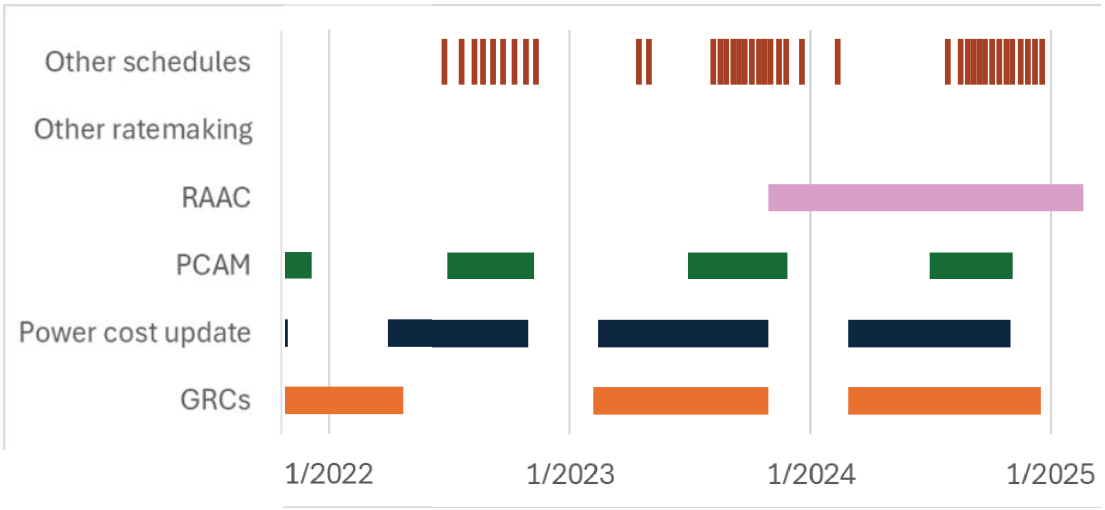
Ratemaking-Related Proceedings Timeline

(Illustrative and not exhaustive)

Portland General Electric proceedings used as an illustration.

Spotlight on 2022-2024; now including thirty-nine Advice Filings impacting rates.



Other schedules: Showing filing dates rather than proceeding length.

Source for this slide and previous: PNNL compilation from dockets UE 435, UE 416, UE 394, UE 427, plus power cost update and PCAM dockets, and thirty-nine Advice Filings from 2022-2024.

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What Happens Between Rate Cases?

Illustrative 5-year Timeline

Rate case

Rate case

Power cost update and PCAM

Power cost update and PCAM

Power cost update and PCAM

Power cost update and PCAM

Power cost update and PCAM

Other schedules updated throughout as needed, for example:

- Transportation electrification
- Community solar
- Income-qualified bill discount program
- Wildfire mitigation cost recovery
- Renewable resource AAC
- Policy compliance costs
- Energy efficiency costs
- Community benefits advisory group
- Major event cost recovery

Other ratemaking application, as determined by the utility

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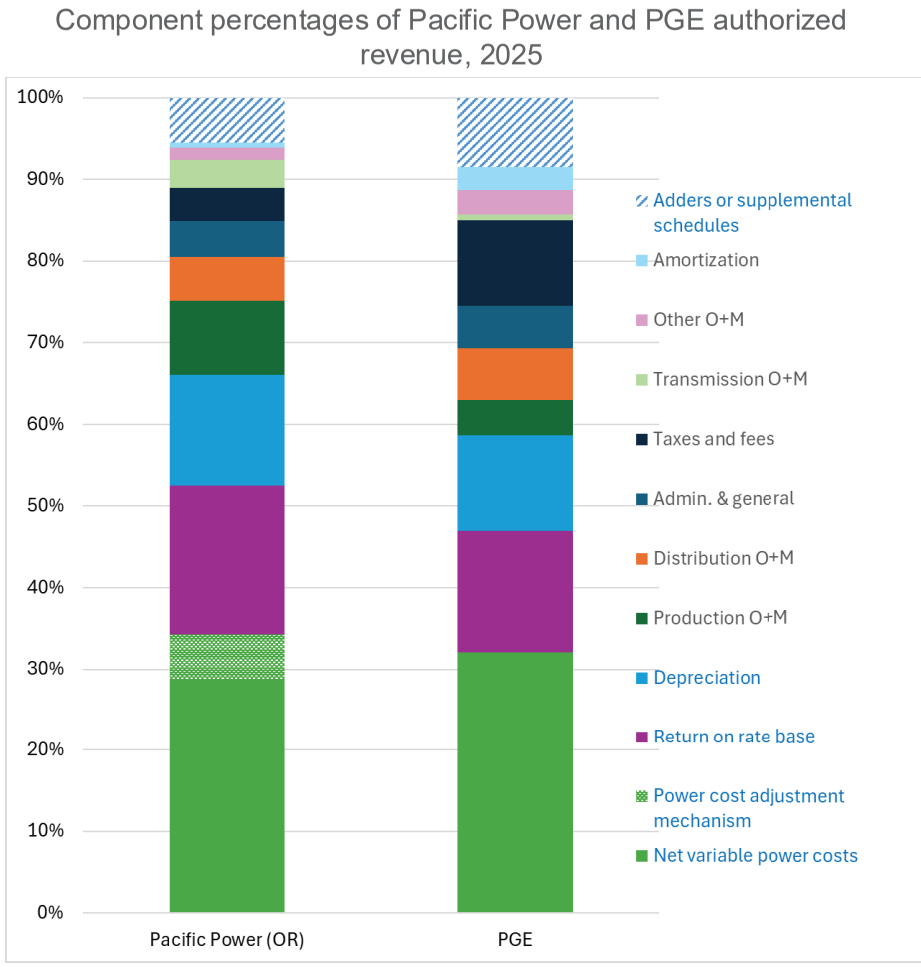
PGE and PacifiCorp 2025 Authorized Revenue



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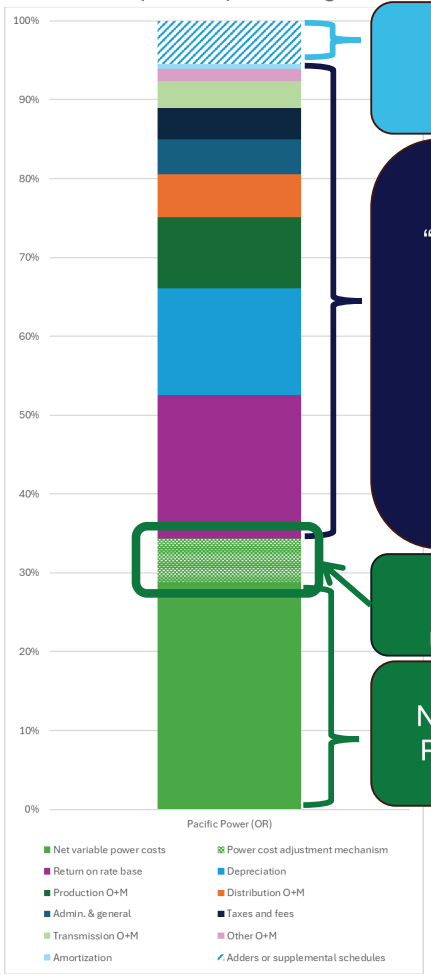
How Rates Are Set (Simplified)

- Using PacifiCorp authorized revenue for illustrative purposes

Chart: Component percentages of Pacific Power authorized revenue, 2025



Adders / Supplemental Schedules
Set in Separate Proceedings (as filed)

~5-8% of Authorized Revenue

"Base Rates" Set in General Rate Cases

Revenue Requirement =
Return on Rate Base + Expenses + Taxes

~60% of Authorized Revenue

Power cost variance mechanism

Net Variable Power Cost

~33% of Authorized Revenue

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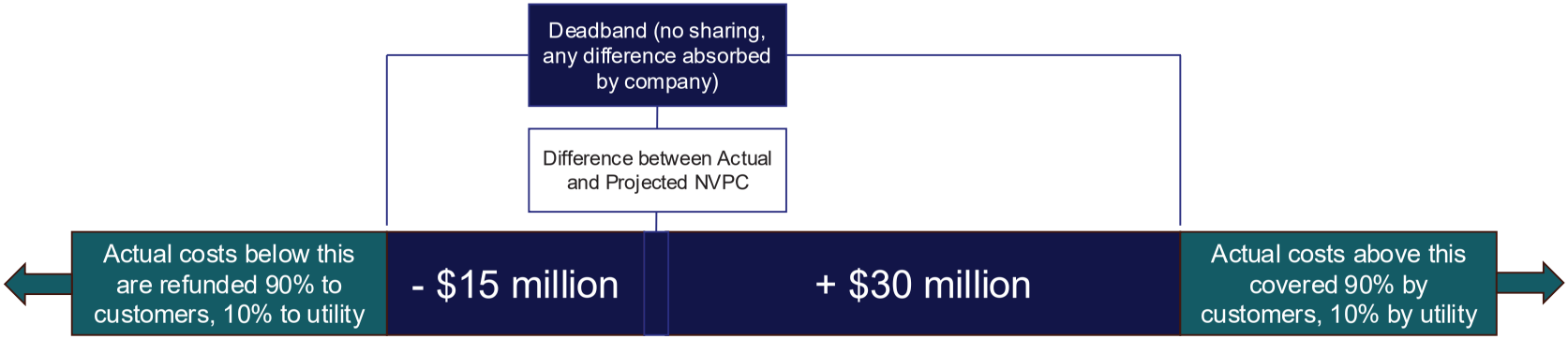
PGE / PacifiCorp Annual Power Cost Variance structure



- Earnings Test: if the utility's earned return on equity (ROE) is within +/- 100 basis points of authorized ROE, there will be no recovery from or refund to customers.
- Amortization cap: the amortization of deferred amounts is capped at 6% of the revenue for the preceding calendar year.

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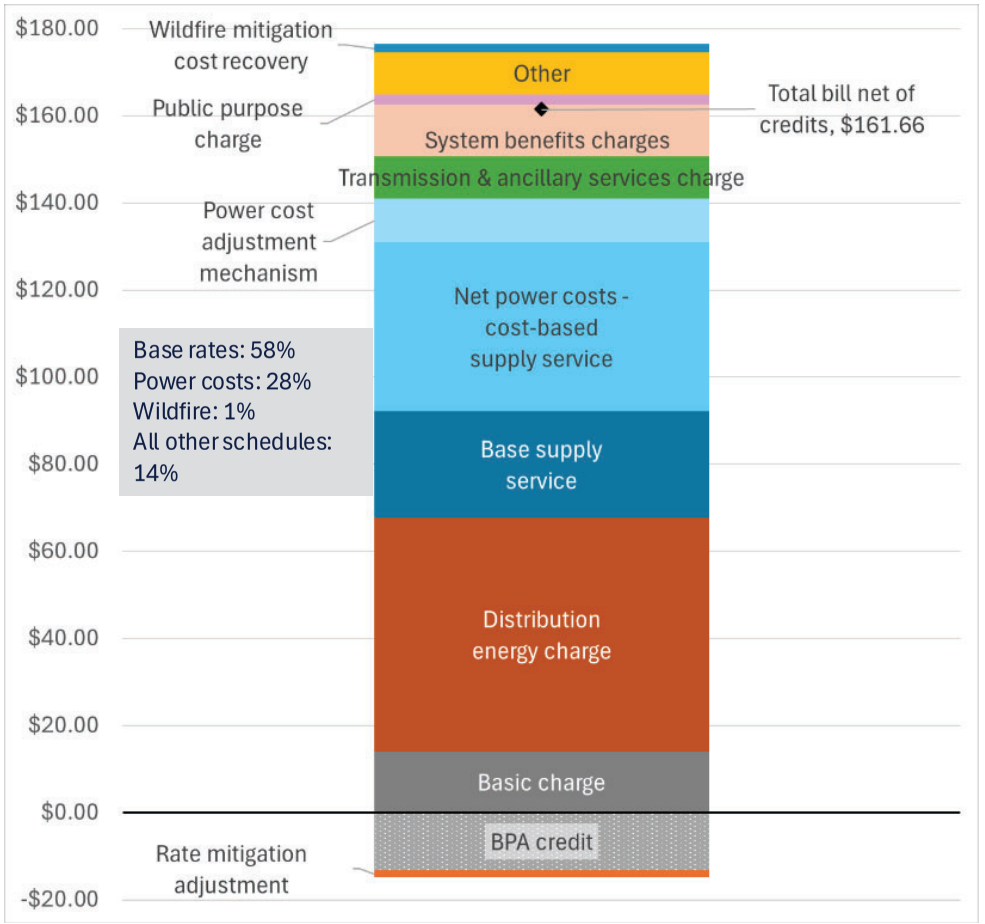
Illustrative 2025 Residential Electric Customer Monthly Bill

- Using PacifiCorp Schedule 4 for illustrative purposes



Note: Illustrative estimate based on 1000 kWh monthly usage

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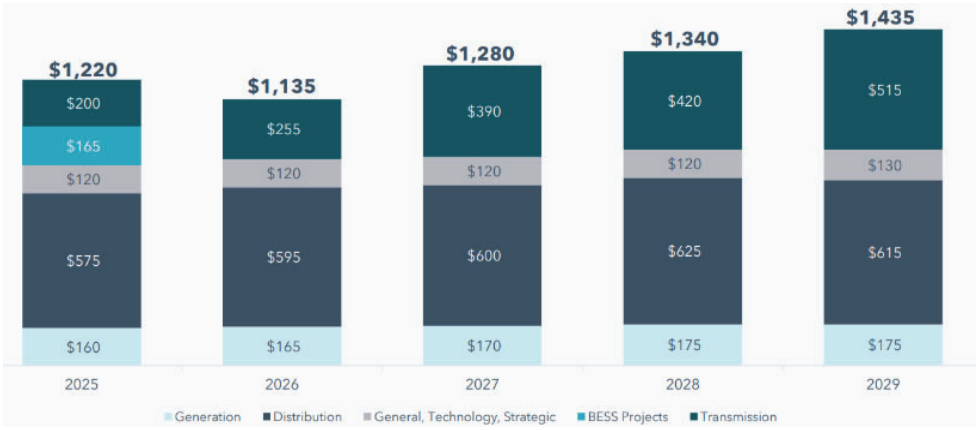
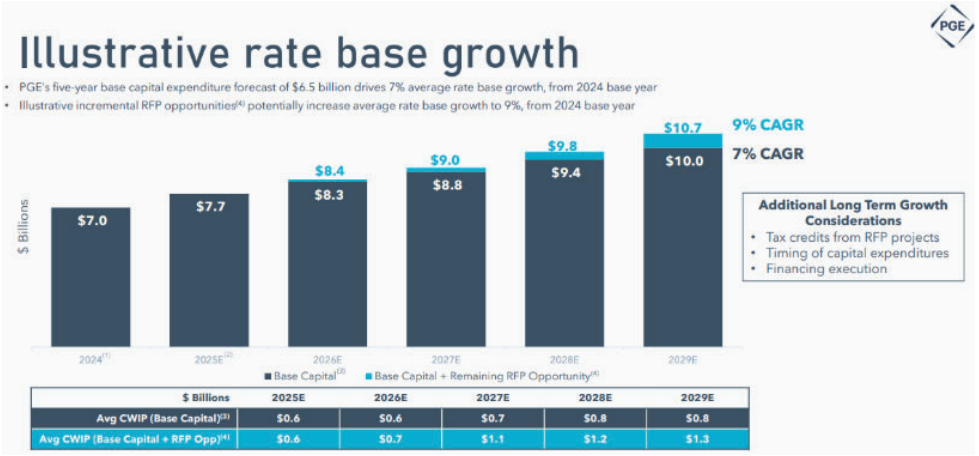
Looking Ahead: PGE potential system investments

Sources:

- October 31, 2025 PGE Investor Presentation
- February 14, 2025 PGE Investor Presentation





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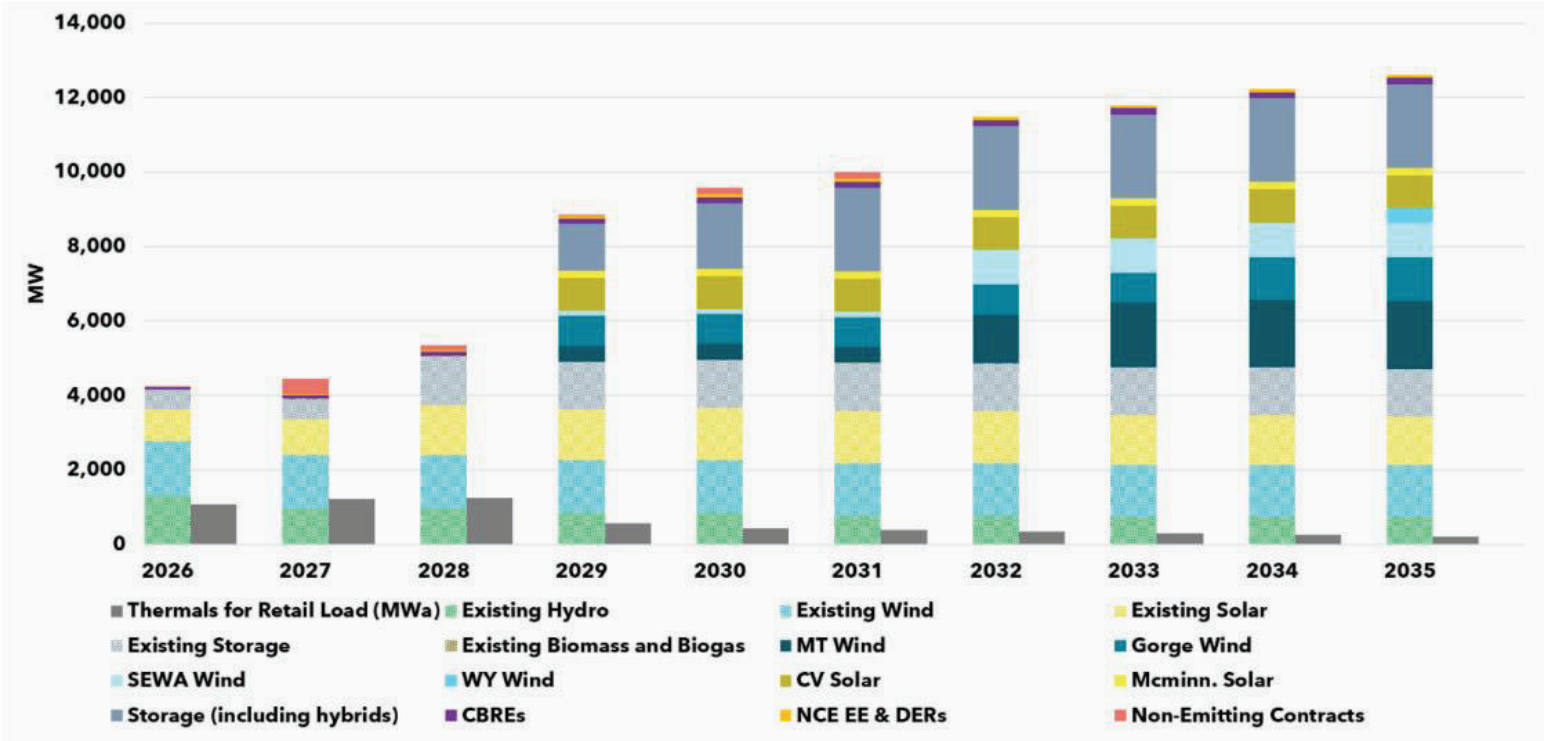
Looking Ahead: PGE Clean Energy Plan



- Source: [PGE 2023 CEP/IRP Update Chapter 6]

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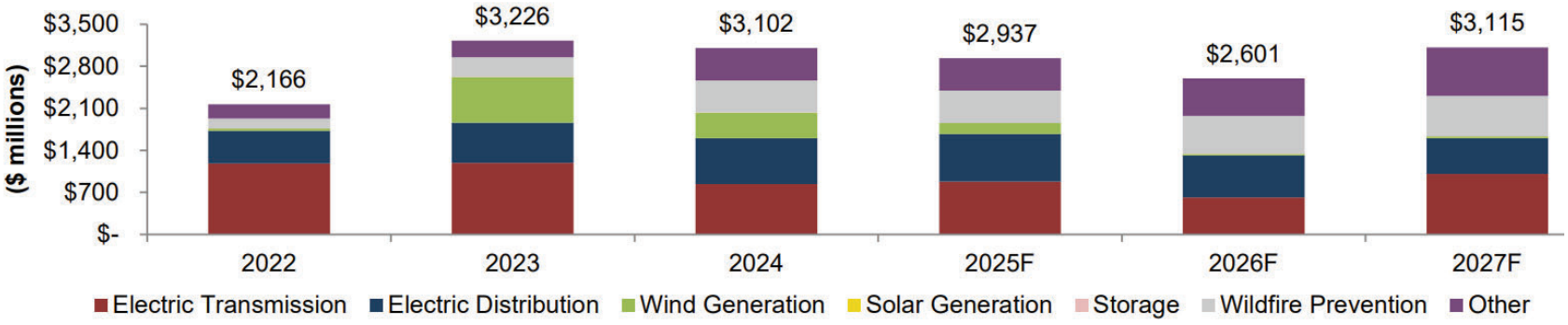
Looking Ahead: PacifiCorp System Investment Trends

Capex by Type *($ millions)*	Current Plan 2025-2027	Prior Plan 2025-2027
Electric Transmission	$ 2,504	$ 3,080
Electric Distribution	2,082	2,124
Wildfire Prevention	1,845	1,821
Wind Generation	238	239
Solar Generation	6	6
Other	1,978	2,091
Total	**$ 8,653**	**$ 9,361**



Source: BHE 2025 Fixed-Income Investor Conference

Looking Ahead: PacifiCorp Oregon CEP

25 CEP Preferred Portfolio OR Shares by Resource Type and Year, Installed MW																						
	Installed Capacity, MW																					
Resource	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Nuclear	-	-	-	-	-	-	-	130	-	-	-	-	-	-	-	-	-	-	-	-	-	130
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	-	-	97	101	107	114	115	110	114	108	109	111	110	105	102	117	122	107	114	92	89	2,045
DSM - Demand Response	-	-	-	48	15	7	-	5	1	3	3	11	-	12	4	23	4	-	9	-	8	153
Renewable - Wind	-	-	-	11	140	1,650	165	128	172	74	-	1	1	-	-	-	-	-	-	-	150	2,491
Renewable - Utility Solar	-	-	-	2	-	414	-	-	-	91	231	243	266	265	257	245	-	-	33	104	-	2,152
Renewable - Small Scale Solar	-	-	-	-	-	275	-	14	19	18	26	27	29	62	-	23	257	154	84	18	26	1,032
Renewable - Battery, < 8 hour	-	-	-	185	1	428	-	-	35	-	25	75	137	145	114	400	180	266	241	-	-	2,231
Renewable - Battery, 24+ hour	-	-	-	-	-	286	-	-	-	8	-	2	-	-	-	823	-	5	128	176	175	1,603

Source: PacifiCorp 2025 Clean Energy Plan Table 25

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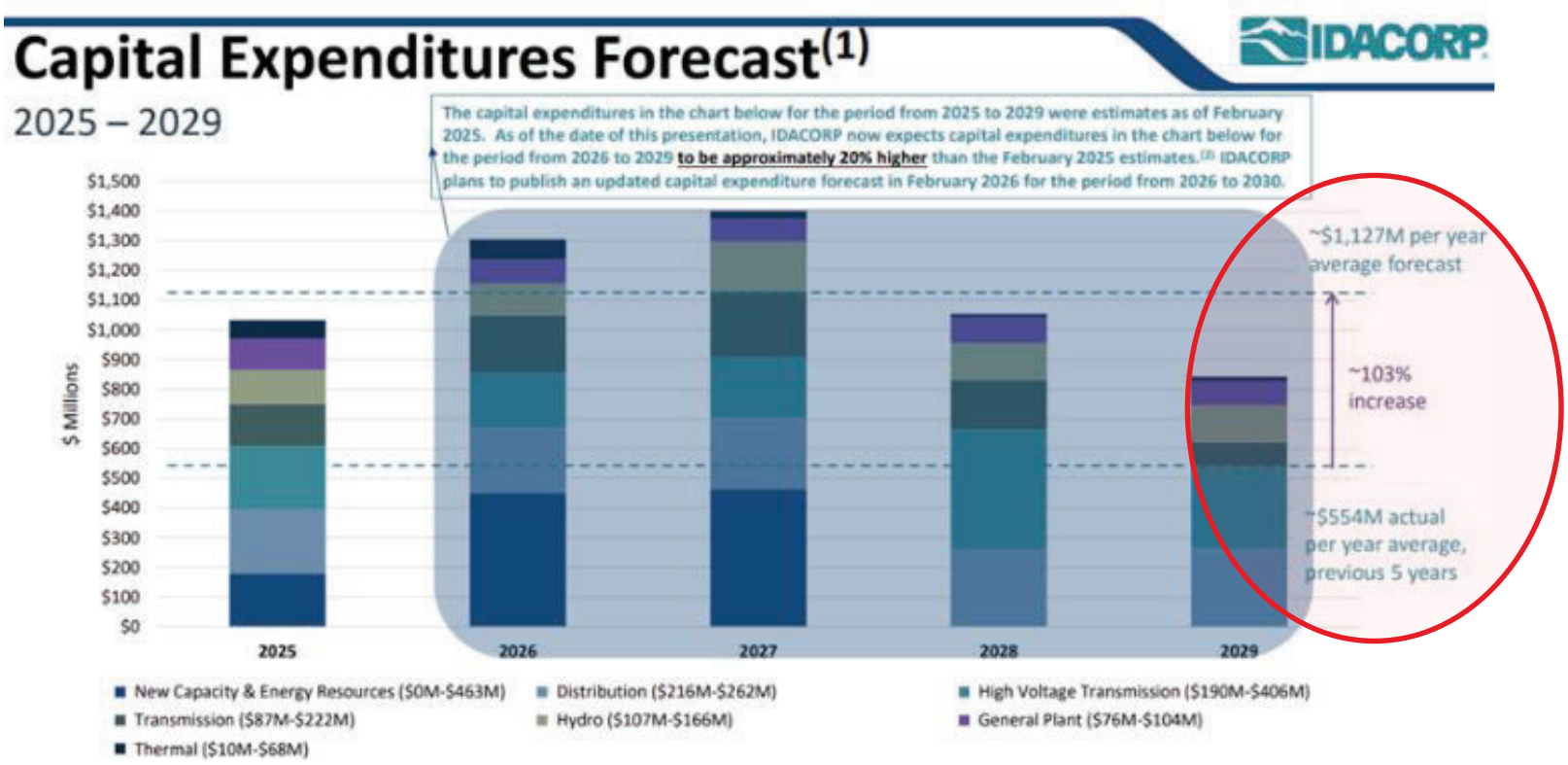
Looking Ahead: Idaho Power



Source: https://s26.q4cdn.com/720254477/files/doc_presentations/2025-12-IDACORP-Investor-Outreach.pdf IDACORP Dec 2025 Investor Outreach.

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Gas Utilities

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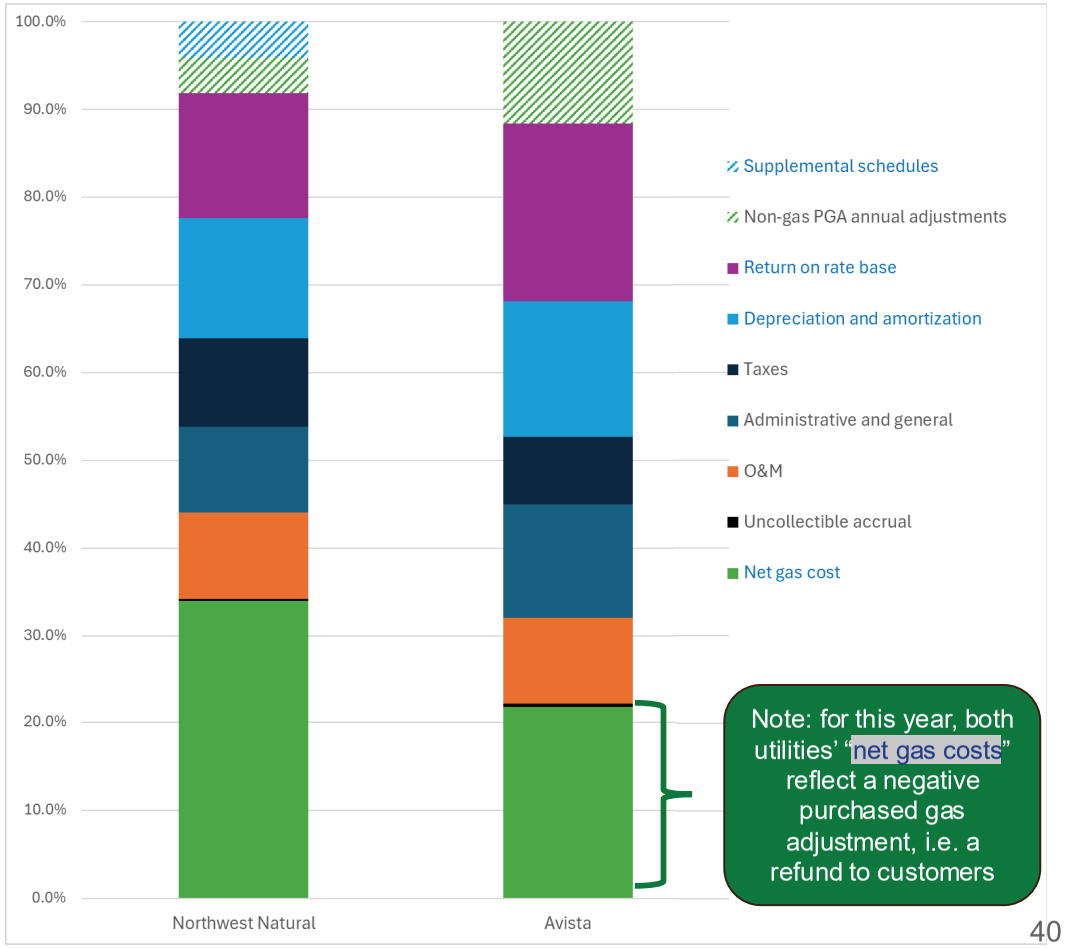
NWN and Avista 2025 Authorized Revenue

Component percentages of Northwest Natural and Avista authorized revenue, 2025



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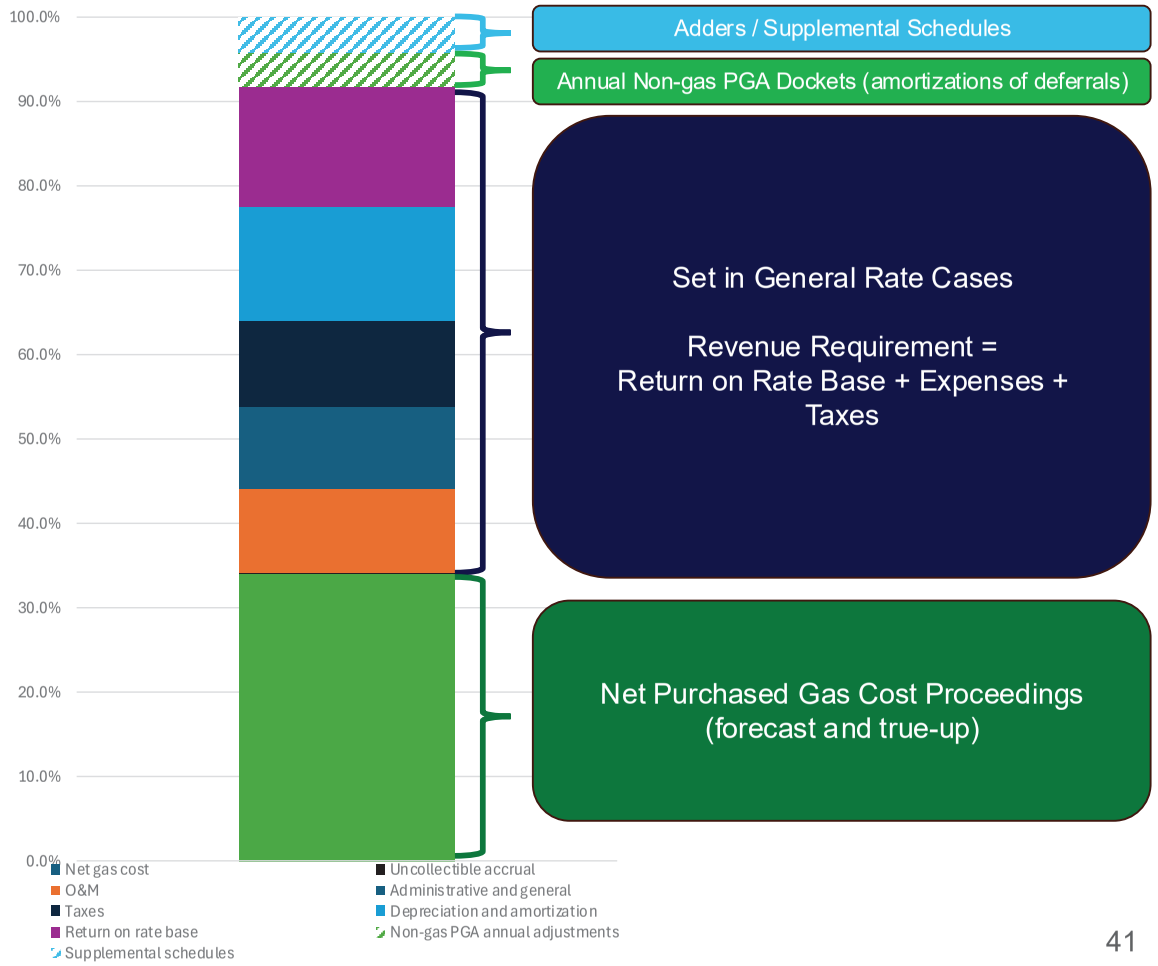
How NG Rates Are Set (Simplified)

- Using Northwest Natural authorized revenue for illustrative purposes

Chart: Component percentages of Northwest Natural authorized revenue, 2025



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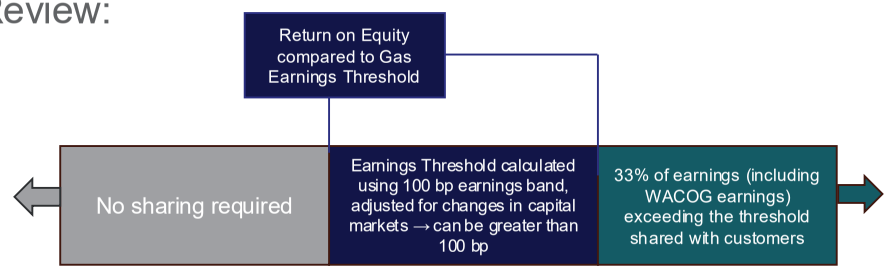
Purchased Gas Adjustment and Spring Earnings Review

- The PGA is designed to recover costs for gas purchases, passing through costs to customers
  - Two components:
    - ✓ Prospective reset of base gas costs (Commodity and Pipeline Capacity components)
    - ✓ Retroactive true-up for differences between actual and base costs

NWN and Avista currently have 90/10 sharing of Weighted Average Cost of Gas (WACOG) variance (90% customers, 10% utility)

- Gas utilities with a PGA are also subject to a Spring Earnings Review:



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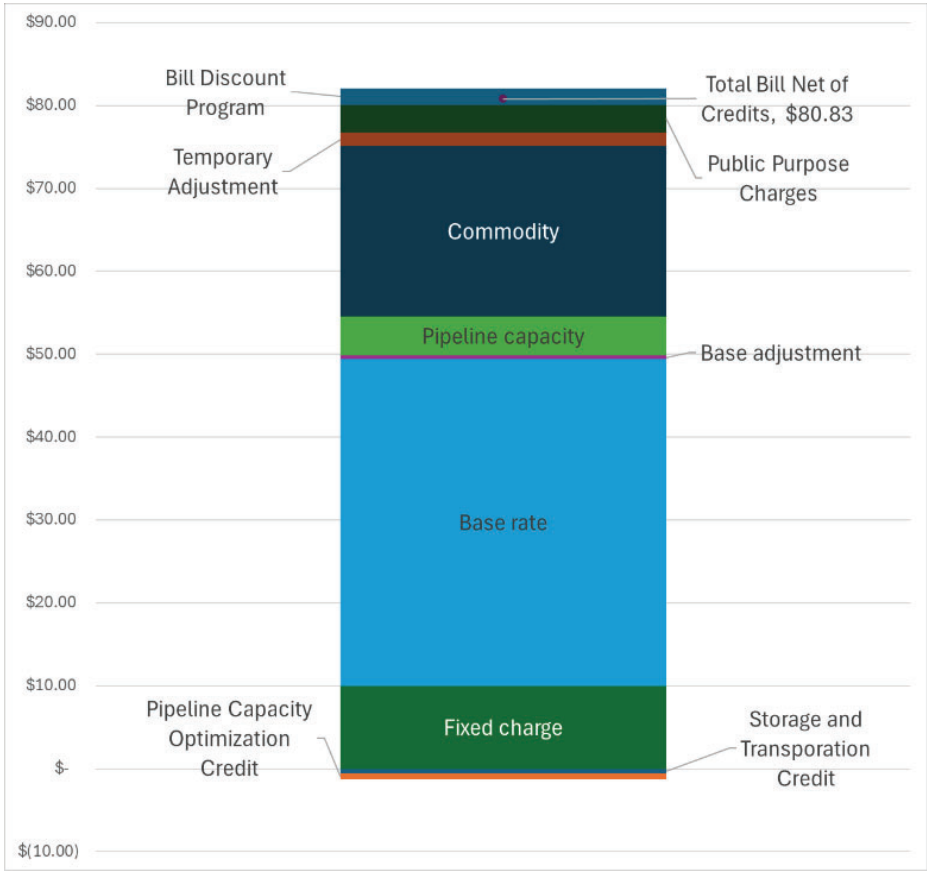
Illustrative 2025 Residential Natural Gas Customer Monthly Bill

- Using Northwest Natural Schedule 2 for illustrative purposes



Note: Illustrative estimate based on 47 therms monthly usage

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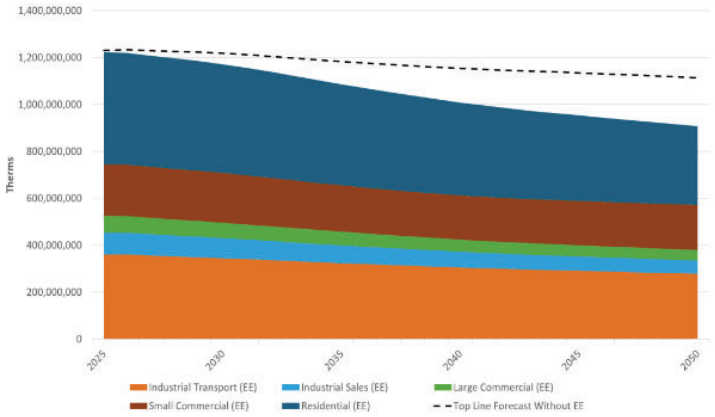
Looking Ahead: NWN Forecast and Future Resource Stack

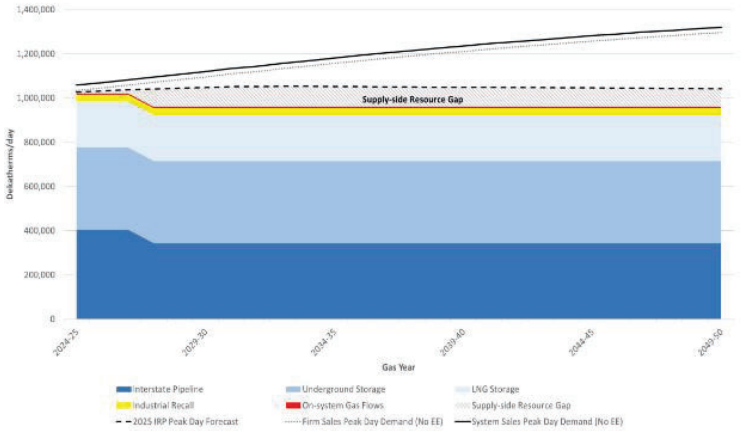
Source:

- [September 2025 OPUC Public Meeting on IRP LC-86]

Forecast Annual System Load



2025 IRP Resource Stack



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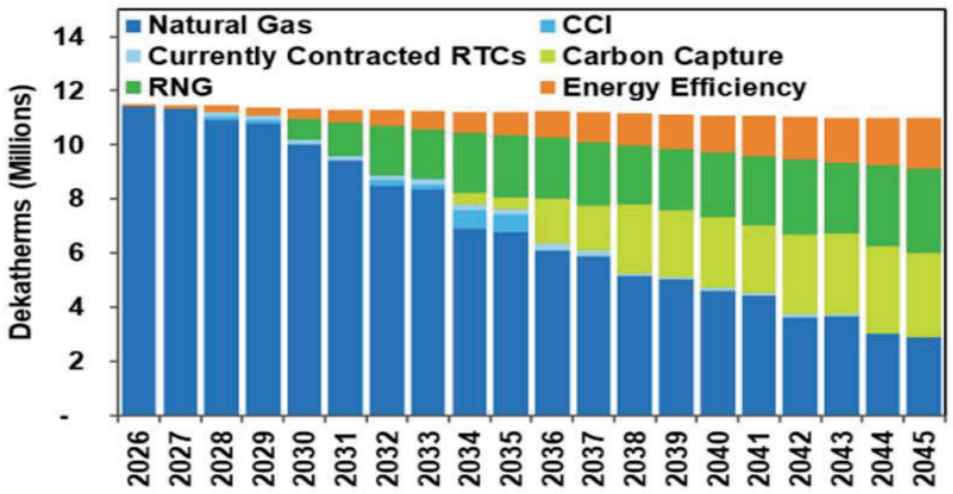
Looking Ahead: Avista

Figure 5: Oregon Preferred Resource Strategy



Avista 2025 Natural Gas Integrated Resource Plan Update, April 2025.
https://edocs.puc.state.or.us/efdocs/HAQ/lc81haq335811026.pdf

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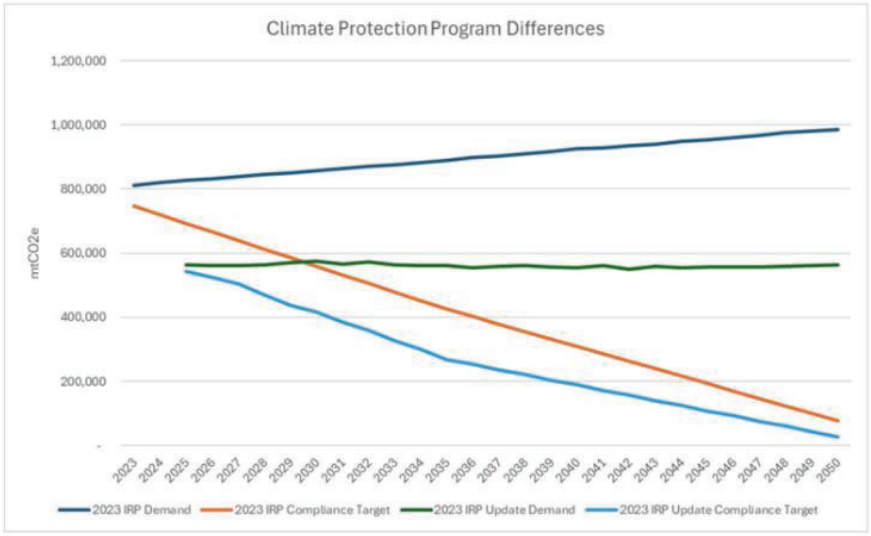
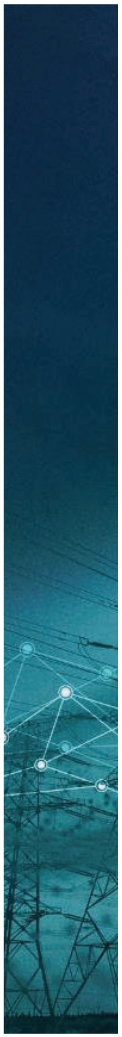
Looking Ahead: Cascade

Figure 8: Climate Protect Program Differences



"In the 2023 IRP, Cascade anticipated 0.86% annual growth in usage after DSM throughout the planning horizon and in the IRP update, Cascade anticipates growth will be relatively flat at 0.03% growth."

Demand and compliance targets in Oregon under the Climate Protection Program. Cascade 2023 IRP Update, May 2025. https://edocs.puc.state.or.us/efdocs/HAH/lc83hah337142055.pdf



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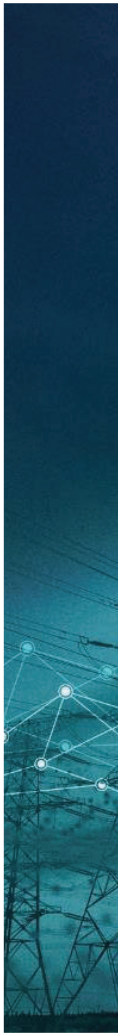
Summary

- Rate cases, power/gas costs and true-up proceedings, other revenue adjustment requests, and other schedules, adders, and automatic adjustment clauses collectively represent a meaningful administrative workload for OPUC staff and others.
- Electric utilities' rates are generally comprised of:
  - Adders / supplemental schedules: 5-8%
  - Base rates: ~60%
  - ✓ Power costs: ~33%
- Gas utilities' rates are generally comprised of:
  - ✓ Adders / supplemental schedules: 8-12%
  - Base rates: 58-66%
  - ✓ Gas costs: 22-34%
- Going forward:
  - Electric utilities expect significant capital investments over the next 3 to 6 years.
  - Gas utilities are exploring flat or reduced load over 20 to 30 years in part due to state policies.



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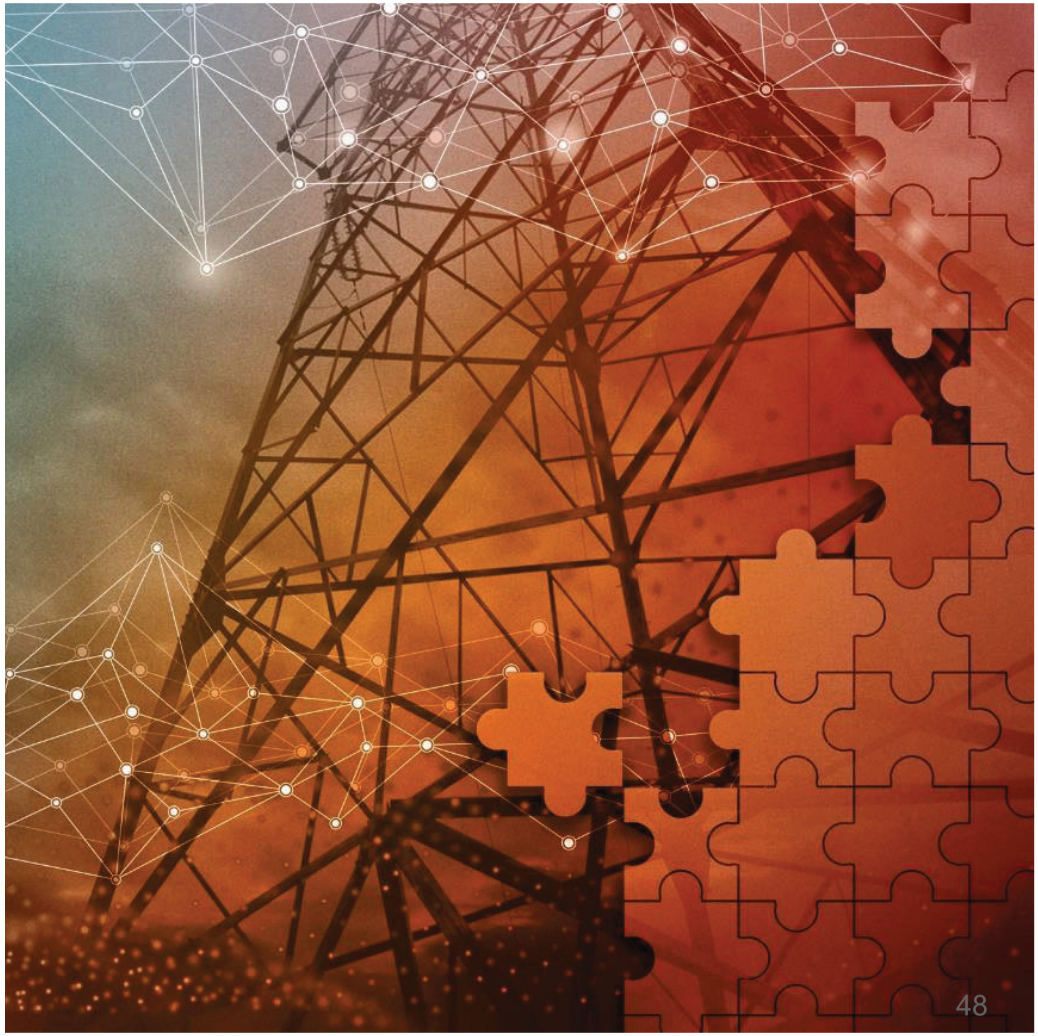
Thank you



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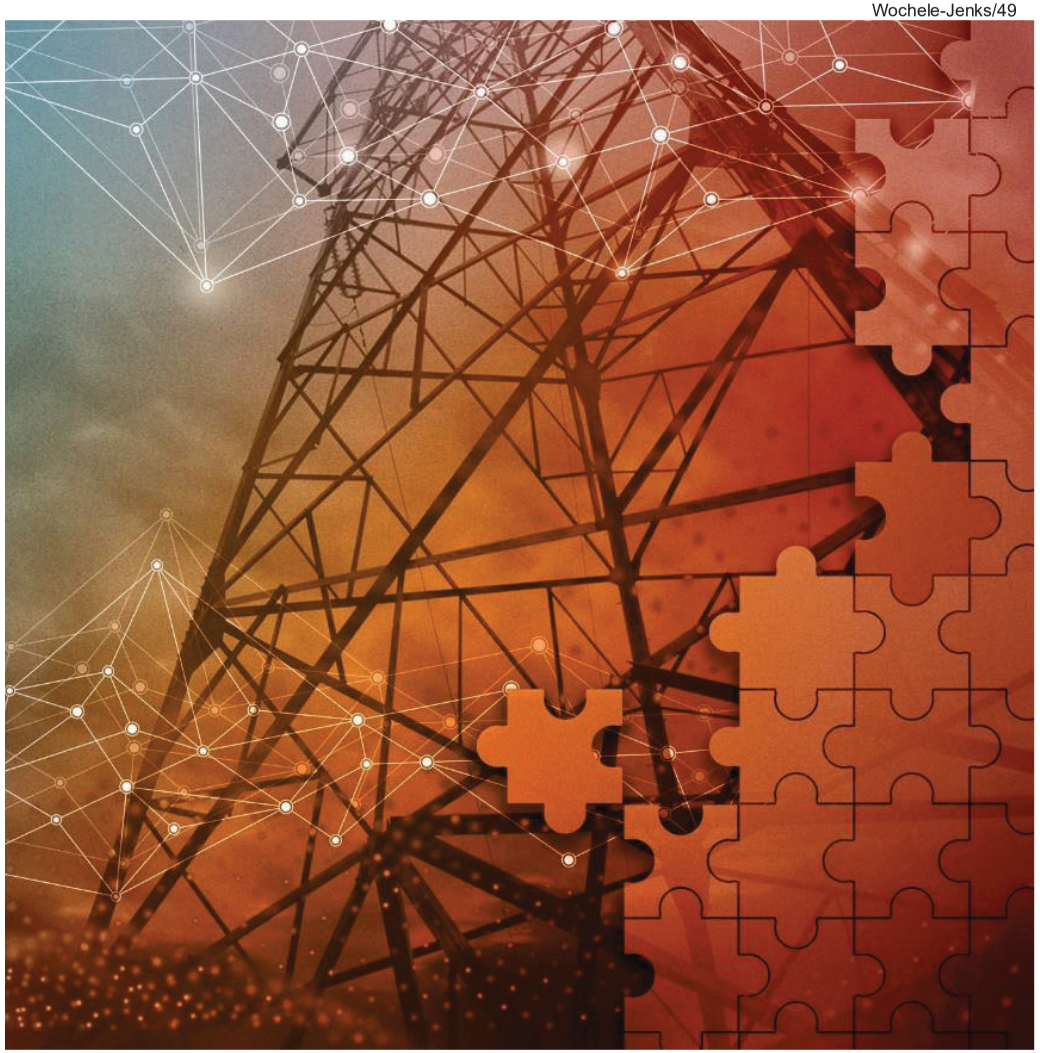
Appendix



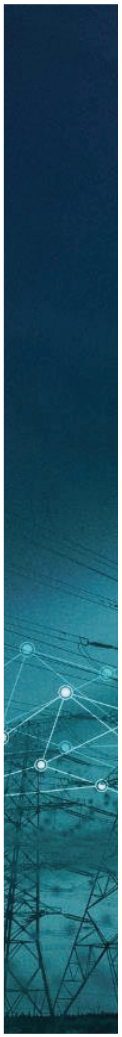
U.S. DEPARTMENT of ENERGY BATTELLE

PNNL is operated by Battelle for the U.S. Department of Energy

Nomenclature – 1/3

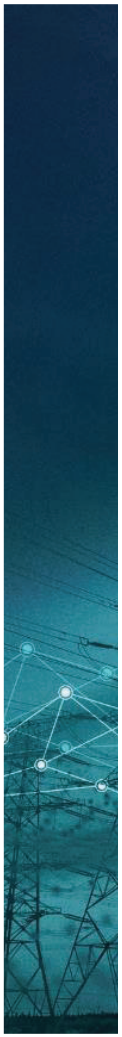
Note: Definitions included here are not necessarily the same definitions as may be used in Oregon statute or rule for the same or a similar term. These definitions have been compiled by PNNL from multiple sources, some of which are cited below.

- **Adders:** a fee, surcharge, or adjustment to energy prices that recovers a specific cost that is not otherwise recovered through base rates.
- **Alternative Rate Mechanism (ARM):** a mechanism to adjust rates that diverges from the traditional, retroactive rate-setting that occurs through rate cases. One use of ARMs is to reduce the time between a utility's investment and cost recovery.
- **Amortization:** the recovery over time of an investment in intangible plant. For example, a payment to a city for entering into a franchise agreement, or the investment in an abandoned power plant that no longer provides service, but for which the regulator has determined cost recovery is appropriate.*
- **Authorized Revenue:** the total amount of money approved by regulators that a utility is authorized to collect from customers. In this analysis, it is being used to mean the total of revenue requirement set in rate cases, plus the net power/gas costs and any supplemental schedules or adders.
- **Automatic Adjustment Clause:** a mechanism that allows for cost recovery outside of a general rate case process. These are typically governed by formulas and rules that are separately evaluated. Historically, these dealt with specific factors that have effects on costs and the company's bottom line and are beyond the control of the utility.
- **Base Rates:** represents the costs that are core to providing service to customers, as determined through a general rate case. Typically consists of the non-power/fuel expenses, such as labor, the return on capital investment, depreciation expense, taxes, and other fees.
- **Cost allocation**: one of the major steps in the regulatory process for setting utility rates where regulators determine how to equitably divide the revenue requirement among several broadly defined classes of ratepayers.
- **Cost effectiveness tests**: Cost-benefit tests are used to determine the cost efficacy of different energy resources to ensure utility customer investments benefit customers, utility systems, and society.
- **Cost of service regulation**: an approach for determining a fair price for electric service that uses aggregate costs for providing each class of service (e.g. residential, commercial, industrial). Prices are set to recover those costs, plus a reasonable return on the invested capital portion of those costs.



Nomenclature – 2/3

- **Decoupling and Decoupling Adjustment:** a regulatory mechanism that separates a utility's collected revenue from its energy sold, ensuring that the authorized revenue requirement is recovered regardless of whether customers consume more or less energy.
- **Depreciation expense:** the recovery over time of a capital investment in a tangible plant that provides service. The return *of* capital (different from the return *on* capital) to the utility's investors over time, as the capital asset is used.*
- **Distributed Energy Resources, or DERs**: Energy resources located on the distribution system, including solar, wind, battery storage, energy efficiency and demand response.
- **Earnings Test**: a mechanism for assessing a utility's overall earnings as compared to an expected level of earnings and using that information to determine whether cost recovery or refunds to customers are appropriate.
- **Gold Plating:** A regulated utility investing more in capital infrastructure than is strictly necessary for the grid's performance or improving customer outcomes.
- **Hosting capacity**: The amount of distributed generation (or demand) that can be added to the distribution system before control changes or system upgrades are required to keep the system safe and reliable and to add more resources
- **Integrated resource plans**: Electricity system planning documents that include a roadmap to meet forecasted energy demand using both supply and demand side resources in the least cost and risk manner.
- **Investor-owned utility**: a utility owned by shareholders or other for-profit owners. A majority of US electricity customers are served by IOUs.
- **Net gas costs:** the net cost of gas supply, including the forecasted costs for the following year and the true-up that results from the PGA calculation described below.
- **Net Variable Power Cost:** the projected cost of the power needed to serve customers for the year ahead, including the cost for utilities to generate its own energy and predicted cost to buy supplemental energy from the wholesale power market.
- **Power Cost Adjustment:** a mechanism to recognize in rates part of the difference for a given year between the actual net variable power costs and the forecasted net variable power costs. The mechanism consists of a deadband, within which no adjustment to rates is made, and a power cost variance amount which dictates the sharing of costs between customers and the utility. The recovery from or refund to customers through the PCA is subject to an earnings review.
- **Prudence:** a regulatory determination by commissions to assess whether a utility project has been completed or implemented as proposed, according to sound management practices, and at a reasonable cost and with reasonable care.
- **Purchased Gas Adjustment:** annual rate mechanism that allows natural gas utilities to pass through the actual costs of buying and transporting natural gas to customers without markup. It accounts for the difference between forecast costs and actual costs and may result in a credit in cases where costs were lower than forecast.

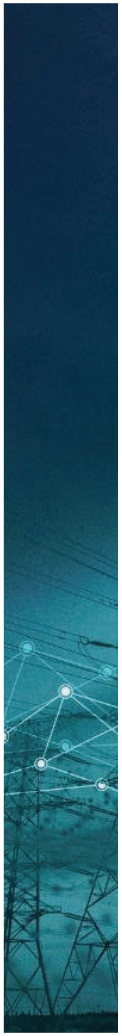


Nomenclature – 3/3

- **Rate base**: the net investment of a utility in property that is used to serve the public. Typically, consists of the original cost net of depreciation, adjusted by working capital, deferred taxes, and various regulatory assets.
- **Rate case**: a formal proceeding, usually before a regulatory commission, involving expert testimony, discovery and briefing, and taking anywhere from 6 to 13 months, principally involving the rates and revenues of a public utility.
- **Rate design:** structure of prices for each component of rates for each class of customers, which are calculated to produce the revenue requirement.
- **Rate of return**: the level of return (profit) that a utility can collect from ratepayers for each source of capital funding the utility receives. Different sources of capital funding have different rates of return. The overall rate of return is calculated by using the weighted average of the cost of debt and common equity within the utility's capital structure.
- **Restructured or deregulated:** Replacement of the traditional vertically integrated utility with some form of competitive market. In some cases, transmission and generation components are purchased by the customer-serving distribution utility in a wholesale competitive market. In others, retail customers are allowed to choose their generation suppliers in a competitive market.
- **Revenue requirement**: the annual revenues that the utility needs to collect to cover its costs, including a return of and on its investment, given an expected level of demand for energy. It is the sum of operation and maintenance expenses, depreciation, taxes, and a return on rate base and often modified by adjustments.
- **Supplemental Schedules:** in this context, this generally means the same thing as an "adder."
- **Used and Useful:** In general, used means that the facility is actually providing service, and useful means that without the facility, either costs would be higher or the quality of service would be lower. However, each state has its own regulatory history that determines what is meant by this term.
- **Vertically integrated:** A utility that owns its own generating plants, transmission system, and distribution lines, providing all aspects of electric service.

Sources for these definitions include the following:

- Lazar, J. (2016). *Electricity Regulation in the US: A Guide. Second Edition.* Montpelier, VT: The Regulatory Assistance Project. https://www.raponline.org/wp-content/uploads/2023/09/rap-lazar-electricity-regulation-US-june-2016.pdf
- Lazar, J., Chernick, P., Marcus, W., and LeBel, M. (Ed.). (2020, January). Electric cost allocation for a new era: A manual. Montpelier, VT: Regulatory Assistance Project. https://www.raponline.org/wp-content/uploads/2023/09/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf



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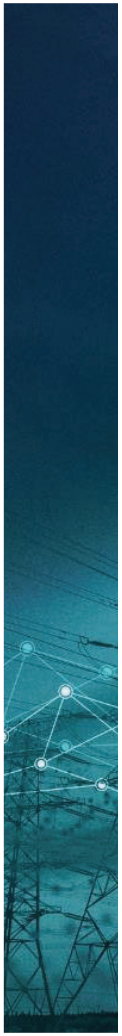
Slide Map - Introduction

1. [Title Slide] Oregon's Existing Utility Rates and Related Mechanisms
2. DOE funding acknowledgement
3. Presentation scope
4. Presentation summary points
5. Rate case timeline showing recent increase in simultaneous rate cases



Slide Map - Electric Utilities

6. [Title Slide] Electric Utilities
7. Timeline of major utility filings, showing how different mechanisms overlap, using one utility as an illustration
8. Timeline of major utility filings, narrowing in on 2022-2024, to show the inclusion of “Advice Filings” overlapping with other mechanisms, using one utility as an illustration
9. Hypothetical 5-year schedule of major rate-related filings
10. Electric utility cost driver breakdown, using two utilities to illustrate the types of costs that construct authorized revenue
11. Electric utility authorized revenue broken down by regulatory or rate-setting mechanism
12. Description of power cost mechanism deadband and sharing
13. Illustrative residential customer monthly bill, assuming customer consumes 1000 kWh
14. PGE forecasted investments by type
15. Summary of 2023 PGE Clean Energy Plan
16. PAC forecasted investments by type
17. Summary of PAC Clean Energy Plan
18. Idaho Power Company forecasted cost drivers

Slide Map – Gas Utilities

19. [Title Slide] Gas Utilities
20. Gas utility cost driver breakdown, using two utilities to illustrate the types of costs that construct authorized revenue
21. Gas utility authorized revenue broken down by regulatory or rate-setting mechanism
22. Description of the Purchased Gas Adjustment (PGA) and Spring Earnings Review
23. Illustrative residential customer monthly bill, assuming customer consumes 47 therms
24. Northwest Natural forecasted system load and cost drivers
25. Avista forecasted cost drivers
26. Cascade Natural Gas forecasted cost drivers

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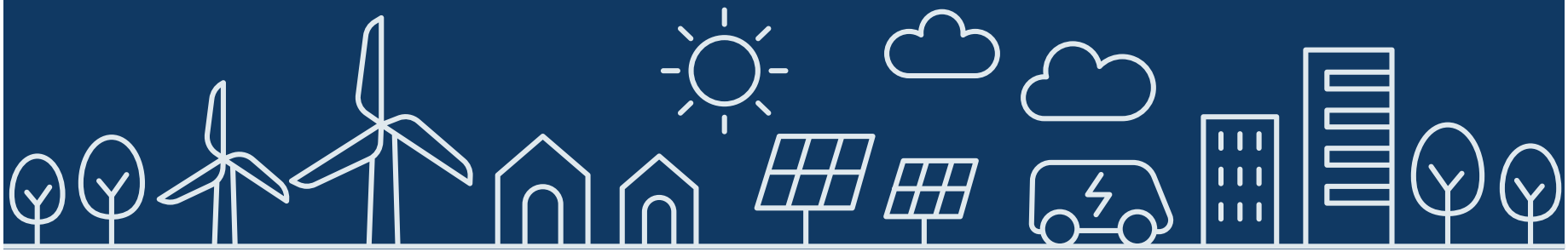
Clarifying Questions



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BREAK

Return at 3:10 pm PT

Breakout Sessions:
Evaluating Oregon's Current Ratemaking Framework

Room 1

Affordable, high-value service

- Affordability *
- **Reduced disconnections ***
- Customer service
- Customer trust
- **Reduced energy burden**
- **Support for vulnerable and low-income customers ***
- Plain language, translated, and regular communications
- **Cost containment**

Room 2

Predictable and efficient regulatory system

- Procedural equity
- **Reduced administrative burden**
- **Stagger rate increases**
- **Reduced rate case frequency**
- **Rate transparency**
- **Narrow and clear tracking mechanisms**
- Standardization in the rate setting and rate case process
- **Smooth and predictable rates and bills**
- **Consolidated rate-setting process**
- **Reduced single-issue ratemaking**
- **Alignment between forecasts and expenses**

Clean energy development

- GHG emission reductions *
- DER expansion *
- **Energy efficiency ***
- Electrification
- Low-carbon fuels
- Community solar expansion *
- Microgrid expansion *
- Demand response expansion *

Room 3

High-performing utility business

- Strategic and efficient capital investment
- **Efficient utility operations ***
- Asset utilization
- **Increased productivity**
- **Safety**
- **Reliability ***
- **Resilience ***
- Financial health
- **Fair earning opportunity**
- Planning
- Interconnection
- **Investments in policy goals**

Asterisk (*): Outcomes identified in SB 688

Bold: Outcomes listed by three or more stakeholders in scoping survey

Room 4

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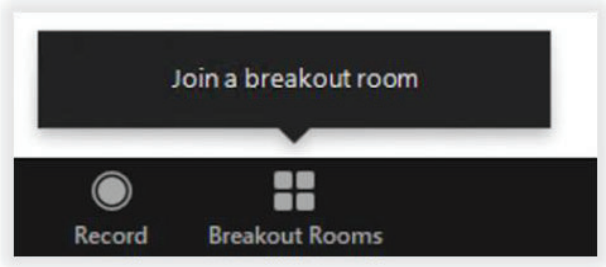
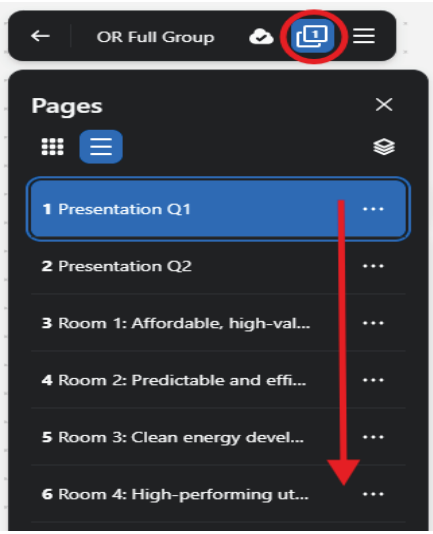
Breakout Sessions: Evaluating Oregon's Current Ratemaking Framework



Select one breakout room based on the following goals:

- **Room 1:** Affordable, high-value service
- **Room 2:** Predictable and efficient regulatory system
- **Room 3:** Clean energy development
- **Room 4:** High-performing utility business



Consider the following for a given goal:

1. Which aspects of Oregon's existing regulatory framework help incentivize alignment with this goal?
2. What aspects of Oregon's existing ratemaking framework could be adjusted/evolved to improve alignment with this goal?

Participants will have the option to switch to a second room after 20 minutes.

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Breakout Sessions: Evaluating Oregon's Current Ratemaking Framework

- Key takeaways from each room
  - **Room 1:** Affordable, high-value service
  - **Room 2:** Predictable and efficient regulatory system
  - **Room 3:** Clean energy development
  - **Room 4:** High-performing utility business

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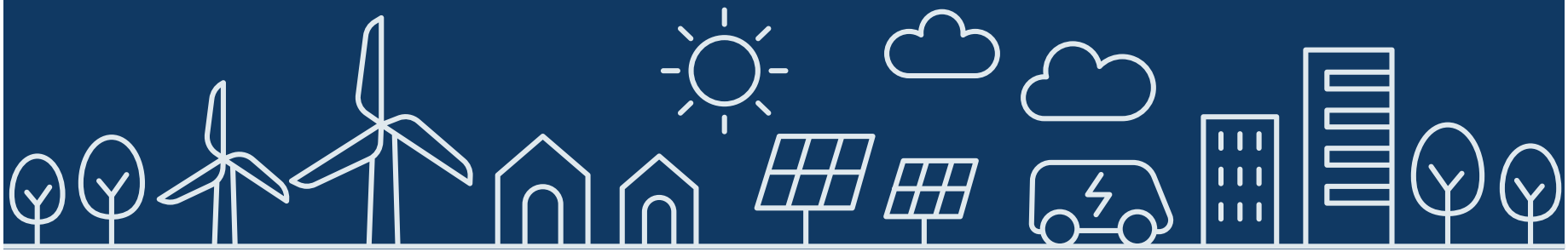
Wrap-Up and Next Steps



UG 527/CUB/113
Wochele-Jenks/62

Wrap-Up and Next Steps

- Next workshop topic: Exploration of MYP and PBR design for Oregon **(early April)**
- Final remarks from Staff

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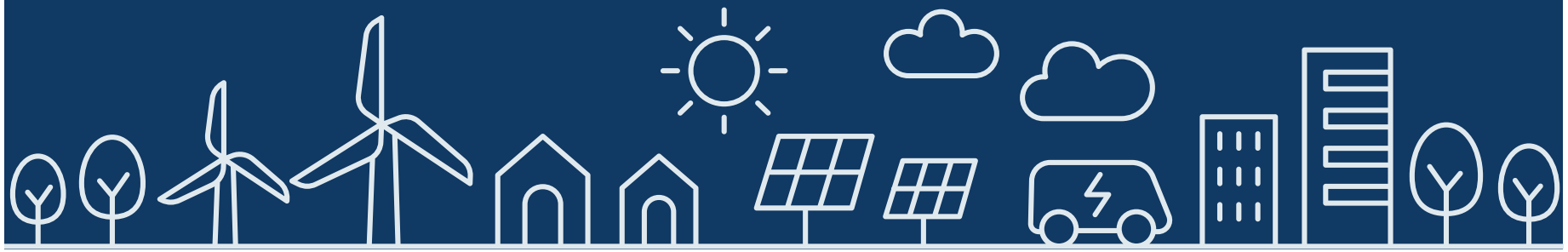
Thank you!

Staff Contacts:

Michelle Scala
michelle.m.scala@puc.oregon.gov

Bret Stevens
bret.stevens@puc.oregon.gov



		Average Monthly UPC (Therms)					
Current Single Family Residential Volumetric Rate	$ 1.41220	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Annual Average**
Proposed Single Family Residential Volumetric Rate	$ 1.43812						
Single Family Residential Fixed Charge	$10.00	77.80	107.93	107.79	90.17	78.74	53.93

	Average Monthly Bill					
	Nov	**Dec**	**Jan**	**Feb**	**Mar**	**Annual Average**
Average Current Bill	$ 119.87	$ 162.42	$ 162.22	$ 137.33	$ 121.20	$ 86.17
Average Proposed Bill	$ 121.89	$ 165.22	$ 165.02	$ 139.67	$ 123.24	$ 87.56

	Average Monthly Bill Increase					
	Nov	**Dec**	**Jan**	**Feb**	**Mar**	**Annual Average**
Average Bill Increase	$ 2.02	$ 2.80	$ 2.79	$ 2.34	$ 2.04	$ 1.39

		Average Monthly Bill Increase EDP Adjusted					
Energy Discount Program Tier		**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Annual Average**
Tier 1	15%	$ 1.71	$ 2.38	$ 2.37	$ 1.99	$ 1.73	$ 1.18
Tier 2	30%	$ 1.41	$ 1.96	$ 1.96	$ 1.64	$ 1.43	$ 0.97
Tier 3	50%	$ 1.01	$ 1.40	$ 1.40	$ 1.17	$ 1.02	$ 0.70
Tier 4	85%	$ 0.30	$ 0.42	$ 0.42	$ 0.35	$ 0.31	$ 0.21

Oregon Public Utility Commission

e-FILING REPORT COVER SHEET

COMPANY NAME: NW Natural

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☐ No ☐ Yes If yes, submit a redacted public version (or a cover letter) by email. Submit the confidential information as directed in OAR 860-001-0070 or the terms of an applicable protective order.

Select report type: ☐ RE (Electric) ☐ RG (Gas) ☐ RW (Water) ☐ RT (Telecommunications)
☐ RO (Other, for example, industry safety information)

Did you previously file a similar report? ☐ No ☐ Yes, report docket number:

Report is required by: ☐ OAR
☐ Statute
☐ Order
Note: A one-time submission required by an order is a compliance filing and not a report (file compliance in the applicable docket)
☐ Other
(For example, federal regulations, or requested by Staff)

Is this report associated with a specific docket/case? ☐ No ☐ Yes, docket number:

List Key Words for this report. We use these to improve search results.

Send the completed Cover Sheet and the Report in an email addressed to PUC.FilingCenter@state.or.us

Send confidential information, voluminous reports, or energy utility Results of Operations Reports to PUC Filing Center, PO Box 1088, Salem, OR 97308-1088 or by delivery service to 201 High Street SE Suite 100, Salem, OR 97301.

NW Natural®

250 SW Taylor Street
Portland, OR 97204

503-226-4211
nwnatural.com

August 14, 2025

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
Post Office Box 1088
Salem, OR 97308-1088

Re: RO 16 – Energy Burden Metrics Report OAR 860-021-0408

In compliance with OAR 860-021-0408, Northwest Natural Gas Company, dba NW Natural, submits herewith the Energy Burden Metrics Reports for the six quarters in the reporting period of January 1, 2024 through June 30, 2025.

Please address correspondence on this matter to me with copies to the following:

eFiling
Rates & Regulatory Affairs
NW Natural
250 SW Taylor Street
Portland, Oregon 97204
Telephone: (503) 610-7330
Fax: (503) 220-2579
Email: eFiling@nwnatural.com

Sincerely,

/s/ Amy Schulties

Amy Schulties
Regulatory Consultant, Regulatory Affairs
NW Natural
250 SW Taylor Street
Portland, OR 97204
Telephone: (503) 610-7546
Email: amy.schulties@nwnatural.com

Enclosures

OREGON PUBLIC UTILITY COMMISSION
ENERGY BURDEN METRICS REPORT QUARTERLY REPORT
DOCKET NO. RO 16
OAR 860-021-0408

Instructions for Filing

General Information

I. Purpose

The Energy Burden Metrics Report is a quarterly reporting requirement for all investor-owned utilities that operate within Oregon. These reports are designed to collect energy burden related metrics and program specific information from utilities. These reports are considered to be non-confidential.

II. Who Must Submit

All investor-owned utilities that operate within Oregon are required to submit this report.

III. When to Submit

Each energy utility must submit a quarterly report within 45 days of the end of each reporting period. For quarterly reporting purposes, the following four reporting periods apply: January 1 to March 31, April 1 to June 30, July 1 to September 30, October 1 to December 31

General Instructions

a. Enter the month and year for each date cell using the following format – "Month Year".
b. For any cell(s) that is not applicable to the respondent enter "NA" or "Not Applicable".
c. For any resubmissions, please explain the reason for the resubmission in a footnote or data field.
d. For average usage metrics, figures should be reported in either kWh or Therms. For total usage metrics, figures should be reported in either MWh or Therms.
e. For average bill metrics, figures should include cents rounded to the second decimal place.
f. For all residential arrearage figures, each residential customer should only be counted only in one group, based on their oldest arrearage balance.
g. If errors or omissions are discovered after a report has been submitted, utilities must submit a revised report within 30 days of identifying the discrepancy.
h. In addition to this form, utilities must submit zip-code level data in an accompanying excel file.

Table 1: Utility Information

Line No.	Field	Description
1	Utility Name	NW Natural
2	Reporting Period	1Q24
3	Date of Submission	8/14/2025

Table 2: Arrearage Information

Line No.	Metric	Month 1	Month 2	Month 3
		Jan-24	Feb-24	Mar-24
1	Total Number of Residential Customers in Arrears	45,351	50,964	49,647
2	31 – 60 days in arrears	21,899	32,226	24,227
3	61 – 90 days in arrears	9,790	7,710	15,634
4	91 or more days in arrears	13,662	11,028	9,786
5	Total Residential Arrears Balance	$6,471,438.56	$7,682,321.98	$7,318,111.83
6	31 – 60 days in arrears	$4,275,152.26	$5,421,186.05	$4,453,641.23
7	61 – 90 days in arrears	$1,052,857.74	$1,181,039.82	$1,703,158.98
8	91 or more days in arrears	$1,143,428.56	$1,080,096.11	$1,161,311.62
9	Total number of customers enrolled in Time Payment Arrangements (TPA) or other extended payment plans	8,858	9,416	9,767

Table 3: Disconnection Information				
Line No.	**Metric**	**Month 1**	**Month 2**	**Month 3**
		Jan-24	Feb-24	Mar-24
1	Total number of active residential accounts	642,904	642,992	643,112
2	Total number of service disconnections for non-payment	590	938	633
3	Total number of disconnection notices sent to residential customers	39,527	43,400	30,976
4	Percentage of accounts with service disconnections for non-payment	0.09%	0.15%	0.10%
5	Total number of bill discount recipient service disconnections for non- payment	208	315	230
6	Total number of energy assistance recipient service disconnections for non- payment	0	0	1
7	Total number of service disconnections for non-payment on medical certificate holder accounts	0	0	0
8	Number of service reconnections following a service disconnection for non- payment on the same day or next calendar day following disconnection	254	350	214
9	Number of service reconnections following a service disconnection for non- payment that occur more than one day and within 7 calendar days following disconnection	111	230	160
10	Number of days on which the energy utility was required to impose a moratorium on service disconnection for severe weather as required by OAR 860-021-0407 (Severe Weather Moratorium on Involuntary Disconnection of Residential Electric or Gas Utility Service)*	2	3	3

*Reported maximum number of days in NW Natural's service territory. Details are in the accompanying data file.

Table 4: Usage and Bill Information				
Line No.	Metric	Month 1	Month 2	Month 3
		Jan-24	Feb-24	Mar-24
1	Total residential usage	69,511,487.40	57,546,010.20	51,983,192.50
2	Average residential usage	107.98	89.39	80.74
3	Average residential bill	$150.92	$110.98	$115.68

Section 5: Bill Discount Program Information				
Line No.	Metric	Month 1	Month 2	Month 3
		Jan-24	Feb-24	Mar-24
1	Total number of residential customers which received a bill discount	35,217	37,323	38,842
2	Tier 1	12,022	12,548	12,938
3	Tier 2	9,426	10,106	10,611
4	Tier 3	8,254	8,775	9,173
5	Tier 4	5,515	5,894	6,120
6	Tier 5			
7	Total dollars provided to bill discount program participants	$1,142,902.07	$894,211.00	$968,551.13
8	Tier 1	$249,508.64	$192,544.89	$207,037.76
9	Tier 2	$278,841.54	$219,499.16	$240,173.55
10	Tier 3	$299,535.24	$233,326.11	$253,631.20
11	Tier 4	$315,016.65	$248,840.84	$267,708.62
12	Tier 5			
13	Total bill discount program costs			
14	Incremental administrative costs	$2,097.56	$0.00	$0.00
15	Applied credits	$1,142,902.07	$894,211.00	$968,551.13
16	Total number of new enrollments	2,214	2207	1738
17	Total number of disenrollments	19	18	21
18	Average bill discount program participant usage			
19	Tier 1	98.56	80.59	73.67
20	Tier 2	105.95	85.88	78.50
21	Tier 3	103.93	83.77	76.63
22	Tier 4	102.11	82.83	75.34
23	Tier 5			
24	Pre-discount average bill discount program participant bill			
25	Tier 1	$140.12	$103.76	$107.96
26	Tier 2	$149.61	$110.07	$114.49
27	Tier 3	$146.82	$107.76	$111.84
28	Tier 4	$145.01	$107.66	$110.59
29	Tier 5			
30	Post-discount average bill discount program participant bill			
31	Tier 1	$119.37	$88.42	$91.95
32	Tier 2	$120.03	$88.35	$91.85
33	Tier 3	$110.53	$81.17	$84.19
34	Tier 4	$87.89	$65.44	$66.85
35	Tier 5			
36	Total number of bill discount program participants with an arrearage balance	7,876	8,433	8,863
37	31 – 60 days in arrears	3,083	3,655	3,447
38	61 – 90 days in arrears	1,902	2,314	3,005
39	91 or more days in arrears	2,891	2,464	2,411
40	Total arrears balance of program participants	$1,159,594.29	$1,423,639.31	$1,422,473.23
41	31 – 60 days in arrears	$668,352.81	$878,994.01	$716,593.23
42	61 – 90 days in arrears	$241,594.45	$313,324.98	$440,405.86
43	91 or more days in arrears	$249,647.03	$231,320.32	$265,474.14

Appendix

Appendix Table 1: Utility Bill Discount Program Information			
Line No.	**Utility Bill Discount Tier *Note: NW Natural's Tiers are numbered 0-4.**	**SMI Range (%)**	**Discount (%)**
1	Tier 1	46% - 60% SMI	15%
2	Tier 2	31% - 45% SMI	20%
3	Tier 3	16% - 30% SMI	25%
4	Tier 4	0% - 15% SMI	40%
5	Tier 5		

Appendix Table 2: Terms & Definitions		
Line No.	**Term**	**Definition**
1	Administrative costs	All incremental expenses related to the management and operation of the bill discount program. This includes, but is not limited to, incremental costs for program design, staff salaries, data processing, customer outreach, eligibility verification, compliance, reporting, and any other overhead or indirect costs necessary to administer the program
2	Applied credits	The aggregate dollar value of discounts applied to the utility bills of residential customers that participate in the utility's bill discount program.
3	Arrearage balance	Any amount of money that a customer owes to the utility company for services provided which remain unpaid past the bill issuance date.
4	Average bill discount program participant usage	The average monthly usage of residential customers enrolled in a utility- administered bill discount program.
5	Average residential bill	The average monthly bill for residential utility services within a utility's Oregon service territory
6	Average residential usage	The average monthly amount of energy billed per residential meter within a utility's Oregon service territory.
7	Disenrollments	Residential customers who were enrolled in a utility's bill discount program as of the previous reporting period but are no longer participating as of the current reporting period. This includes customers who were removed from the program due to ineligibility or non-compliance.
8	Energy assistance recipient	A residential customer who has received bill payment assistance with an energy bill from any federal, state, customer-funded, bill payment assistance fund or program at least once within the past 12 months.
9	New enrollments	Residential customers enrolled in a utility's bill discount program for the first time within the current calendar year.
10	Pre-discount average bill discount program participant bill	The average monthly utility bill amount for bill discount program participants before the application of any bill discounts.
11	Post-discount average bill discount program participant bill	The average monthly utility bill amount for bill discount program participants after the application of their respective bill discount.
12	Residential customer	Any individual or household that receives utility services for personal, non- commercial use. This includes all customers being served on a utility's residential service tariff.
13	Service disconnection for non-payment	Any instances where utility service to a residential account was terminated due to the customer's failure to pay their utility bill.
14	Disconnection notice	Any written or electronic notification issued by a utility to a customer in accordance with OAR 860-021-0405 (3).
15	Total arrears balance of bill discount program participants	The total dollar amount of outstanding balances owed by residential customers enrolled in a utility-administered bill discount program on their utility bills.
16	Total dollars provided to bill discount program participants	The aggregate dollar value of discounts applied to the utility bills of residential customers who participate in the utility's bill discount program.
17	Total bill discount program costs	The total expenditure incurred by a utility in administering its bill discount program for low-income residential customers.
18	Total residential arrearage balances	The total dollar amount of outstanding balances owed by residential customers on their utility bills.
19	31-60 days in arrears	A customer who has an arrearage balance that has been unpaid for a period of between 31 and 60 days from the original bill issuance date.
20	61-90 days in arrears	A customer who has an arrearage balance that has been unpaid for a period of between 61 and 90 days from the original bill issuance date.
21	91+ days in arrears	A customer who has an arrearage balance that has been unpaid for a period greater than 90 days from the original bill issuance date.

OREGON PUBLIC UTILITY COMMISSION
ENERGY BURDEN METRICS REPORT QUARTERLY REPORT
DOCKET NO. RO 16
OAR 860-021-0408

Instructions for Filing

General Information

I. Purpose

The Energy Burden Metrics Report is a quarterly reporting requirement for all investor-owned utilities that operate within Oregon. These reports are designed to collect energy burden related metrics and program specific information from utilities. These reports are considered to be non-confidential.

II. Who Must Submit

All investor-owned utilities that operate within Oregon are required to submit this report.

III. When to Submit

Each energy utility must submit a quarterly report within 45 days of the end of each reporting period. For quarterly reporting purposes, the following four reporting periods apply: January 1 to March 31, April 1 to June 30, July 1 to September 30, October 1 to December 31

General Instructions

a. Enter the month and year for each date cell using the following format – "Month Year".
b. For any cell(s) that is not applicable to the respondent enter "NA" or "Not Applicable".
c. For any resubmissions, please explain the reason for the resubmission in a footnote or data field.
d. For average usage metrics, figures should be reported in either kWh or Therms. For total usage metrics, figures should be reported in either MWh or Therms.
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f. For all residential arrearage figures, each residential customer should only be counted only in one group, based on their oldest arrearage balance.
g. If errors or omissions are discovered after a report has been submitted, utilities must submit a revised report within 30 days of identifying the discrepancy.
h. In addition to this form, utilities must submit zip-code level data in an accompanying excel file.

Table 1: Utility Information

Line No.	Field	Description
1	Utility Name	NW Natural
2	Reporting Period	2Q24
3	Date of Submission	8/14/2025

Table 2: Arrearage Information

Line No.	Metric	Month 1	Month 2	Month 3
		Apr-24	May-24	Jun-24
1	Total Number of Residential Customers in Arrears	51,203	50,216	54,138
2	31 – 60 days in arrears	29,823	23,035	27,713
3	61 – 90 days in arrears	9,304	15,916	10,838
4	91 or more days in arrears	12,076	11,265	15,587
5	Total Residential Arrears Balance	$6,908,960	$6,194,965	$5,917,162
6	31 – 60 days in arrears	$4,089,330	$3,204,468	$2,716,237
7	61 – 90 days in arrears	$1,380,643	$1,512,652	$1,376,398
8	91 or more days in arrears	$1,438,988	$1,477,845	$1,824,526
9	Total number of customers enrolled in Time Payment Arrangements (TPA) or other extended payment plans	10,108	10,100	9,824

Table 3: Disconnection Information				
Line No.	**Metric**	**Month 1**	**Month 2**	**Month 3**
		Apr-24	May-24	Jun-24
1	Total number of active residential accounts	643,915	644,027	644,368
2	Total number of service disconnections for non-payment	906	1209	869
3	Total number of disconnection notices sent to residential customers	34,731	23,029	17,476
4	Percentage of accounts with service disconnections for non-payment	0.14%	0.19%	0.13%
5	Total number of bill discount recipient service disconnections for non- payment	315	502	333
6	Total number of energy assistance recipient service disconnections for non- payment	3	16	13
7	Total number of service disconnections for non-payment on medical certificate holder accounts	0	0	0
8	Number of service reconnections following a service disconnection for non- payment on the same day or next calendar day following disconnection	271	322	212
9	Number of service reconnections following a service disconnection for non- payment that occur more than one day and within 7 calendar days following disconnection	217	259	215
10	Number of days on which the energy utility was required to impose a moratorium on service disconnection for severe weather as required by OAR 860-021-0407 (Severe Weather Moratorium on Involuntary Disconnection of Residential Electric or Gas Utility Service)*	0	0	0

*Reported maximum number of days in NW Natural's service territory. Details are in the accompanying data file.

Table 4: Usage and Bill Information				
Line No.	Metric	Month 1	Month 2	Month 3
		Apr-24	May-24	Jun-24
1	Total residential usage	34,160,929	25,679,246	15,999,926
2	Average residential usage	52.99	39.83	24.80
3	Average residential bill	$77.37	$61.45	$41.08

Section 5: Bill Discount Program Information				
Line No.	Metric	Month 1	Month 2	Month 3
		Apr-24	May-24	Jun-24
1	Total number of residential customers which received a bill discount	39,862	40,491	40,636
2	Tier 1	13,144	13,350	13,449
3	Tier 2	10,992	11,212	11,257
4	Tier 3	9,445	9,553	9,553
5	Tier 4	6,281	6,376	6,377
6	Tier 5			
7	Total dollars provided to bill discount program participants	$684,248.76	$539,225.22	$362,569.59
8	Tier 1	$145,210.50	$114,876.10	$77,861.72
9	Tier 2	$169,354.41	$134,593.24	$89,415.19
10	Tier 3	$179,135.73	$140,465.94	$94,563.71
11	Tier 4	$190,548.12	$149,289.94	$100,728.97
12	Tier 5			
13	Total bill discount program costs			
14	Incremental administrative costs	$0.00	$0.00	$0.00
15	Applied credits	$684,248.76	$539,225.22	$362,569.59
16	Total number of new enrollments	1,381	1342	926
17	Total number of disenrollments	21	458	511
18	Average bill discount program participant usage			
19	Tier 1	73.67	49.37	36.62
20	Tier 2	78.50	52.23	38.88
21	Tier 3	76.63	50.82	37.95
22	Tier 4	75.34	50.73	37.44
23	Tier 5			
24	Pre-discount average bill discount program participant bill			
25	Tier 1	$74.88	$58.49	$39.39
26	Tier 2	$78.35	$61.38	$41.00
27	Tier 3	$77.12	$60.04	$40.90
28	Tier 4	$77.19	$59.72	$40.82
29	Tier 5			
30	Post-discount average bill discount program participant bill			
31	Tier 1	$63.83	$49.89	$33.60
32	Tier 2	$62.95	$49.37	$33.06
33	Tier 3	$58.16	$45.33	$31.00
34	Tier 4	$46.85	$36.31	$25.03
35	Tier 5			
36	Total number of bill discount program participants with an arrearage balance	8,806	9,082	9,249
37	31 – 60 days in arrears	3,395	3,165	2,936
38	61 – 90 days in arrears	2,660	2,971	2,578
39	91 or more days in arrears	2,751	2,946	3,735
40	Total arrears balance of program participants	$1,371,444.49	$1,264,057.27	$1,156,163.07
41	31 – 60 days in arrears	$677,708.22	$517,445.84	$410,995.59
42	61 – 90 days in arrears	$344,456.79	$366,562.36	$305,534.21
43	91 or more days in arrears	$349,279.48	$380,049.07	$439,633.27

Appendix

Appendix Table 1: Utility Bill Discount Program Information

Line No.	Utility Bill Discount Tier *Note: NW Natural's Tiers are numbered 0-4.	SMI Range (%)	Discount (%)
1	Tier 1	46% - 60% SMI	15%
2	Tier 2	31% - 45% SMI	20%
3	Tier 3	16% - 30% SMI	25%
4	Tier 4	0% - 15% SMI	40%
5	Tier 5		

Appendix Table 2: Terms & Definitions

Line No.	Term	Definition
1	Administrative costs	All incremental expenses related to the management and operation of the bill discount program. This includes, but is not limited to, incremental costs for program design, staff salaries, data processing, customer outreach, eligibility verification, compliance, reporting, and any other overhead or indirect costs necessary to administer the program
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14	Disconnection notice	Any written or electronic notification issued by a utility to a customer in accordance with OAR 860-021-0405 (3).
15	Total arrears balance of bill discount program participants	The total dollar amount of outstanding balances owed by residential customers enrolled in a utility-administered bill discount program on their utility bills.
16	Total dollars provided to bill discount program participants	The aggregate dollar value of discounts applied to the utility bills of residential customers who participate in the utility's bill discount program.
17	Total bill discount program costs	The total expenditure incurred by a utility in administering its bill discount program for low-income residential customers.
18	Total residential arrearage balances	The total dollar amount of outstanding balances owed by residential customers on their utility bills.
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20	61-90 days in arrears	A customer who has an arrearage balance that has been unpaid for a period of between 61 and 90 days from the original bill issuance date.
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Table 1: Utility Information

Line No.	Field	Description
1	Utility Name	NW Natural
2	Reporting Period	3Q24
3	Date of Submission	8/14/2025

Table 2: Arrearage Information

Line No.	Metric	Month 1	Month 2	Month 3
		Jul-24	Aug-24	Sep-24
1	Total Number of Residential Customers in Arrears	52,718	54,789	57,007
2	31 – 60 days in arrears	24,514	24,149	23,697
3	61 – 90 days in arrears	12,342	12,396	11,491
4	91 or more days in arrears	15,862	18,244	21,819
5	Total Residential Arrears Balance	$4,898,960	$4,255,535	$4,154,894
6	31 – 60 days in arrears	$1,771,080	$1,370,970	$1,298,419
7	61 – 90 days in arrears	$1,149,156	$929,279	$801,140
8	91 or more days in arrears	$1,978,724	$1,955,286	$2,055,335
9	Total number of customers enrolled in Time Payment Arrangements (TPA) or other extended payment plans	9,524	9,044	8,623

Table 3: Disconnection Information				
Line No.	**Metric**	**Month 1**	**Month 2**	**Month 3**
		Jul-24	Aug-24	Sep-24
1	Total number of active residential accounts	643,678	643,683	643,502
2	Total number of service disconnections for non-payment	1058	997	56
3	Total number of disconnection notices sent to residential customers	14,241	5,651	5,686
4	Percentage of accounts with service disconnections for non-payment	0.16%	0.15%	0.01%
5	Total number of bill discount recipient service disconnections for non- payment	471	462	27
6	Total number of energy assistance recipient service disconnections for non- payment	26	30	1
7	Total number of service disconnections for non-payment on medical certificate holder accounts	0	0	0
8	Number of service reconnections following a service disconnection for non- payment on the same day or next calendar day following disconnection	250	218	11
9	Number of service reconnections following a service disconnection for non- payment that occur more than one day and within 7 calendar days following disconnection	206	210	17
10	Number of days on which the energy utility was required to impose a moratorium on service disconnection for severe weather as required by OAR 860-021-0407 (Severe Weather Moratorium on Involuntary Disconnection of Residential Electric or Gas Utility Service)*	0	1	0

*Reported maximum number of days in NW Natural's service territory. Details are in the accompanying data file.

Table 4: Usage and Bill Information				
Line No.	Metric	Month 1	Month 2	Month 3
		Jul-24	Aug-24	Sep-24
1	Total residential usage	9,317,559	7,596,979	8,544,866
2	Average residential usage	24.8	14.45	11.78
3	Average residential bill	$41.08	$27.63	$24.20

Section 5: Bill Discount Program Information				
Line No.	Metric	Month 1	Month 2	Month 3
		Jul-24	Aug-24	Sep-24
1	Total number of residential customers which received a bill discount	40,710	41,040	41,272
2	Tier 1	13,510	13,443	13,296
3	Tier 2	11,260	11,438	11,631
4	Tier 3	9,546	9,695	9,826
5	Tier 4	6,394	6,464	6,519
6	Tier 5			
7	Total dollars provided to bill discount program participants	$246,153.39	$219,364.85	$236,905.13
8	Tier 1	$53,371.95	$46,772.98	$49,663.86
9	Tier 2	$59,799.29	$53,306.52	$58,500.14
10	Tier 3	$64,146.54	$58,027.09	$62,469.32
11	Tier 4	$68,835.61	$61,258.26	$66,271.81
12	Tier 5			
13	Total bill discount program costs			
14	Incremental administrative costs	$0.00	$0.00	$0.00
15	Applied credits	$246,153.39	$219,364.85	$236,905.13
16	Total number of new enrollments	1,001	1002	796
17	Total number of disenrollments	76	39	42
18	Average bill discount program participant usage			
19	Tier 1	22.86	13.44	11.01
20	Tier 2	23.63	13.62	11.04
21	Tier 3	23.65	13.80	11.55
22	Tier 4	23.41	13.89	11.25
23	Tier 5			
24	Pre-discount average bill discount program participant bill			
25	Tier 1	$27.33	$24.21	$25.77
26	Tier 2	$27.52	$24.33	$26.18
27	Tier 3	$27.72	$25.25	$26.41
28	Tier 4	$27.95	$25.16	$26.18
29	Tier 5			
30	Post-discount average bill discount program participant bill			
31	Tier 1	$23.38	$20.73	$22.04
32	Tier 2	$22.21	$19.67	$21.15
33	Tier 3	$21.00	$19.27	$20.05
34	Tier 4	$17.18	$15.68	$16.01
35	Tier 5			
36	Total number of bill discount program participants with an arrearage balance	8,982	8,974	9,018
37	31 – 60 days in arrears	2,675	2,609	2,470
38	61 – 90 days in arrears	2,266	2,043	1,730
39	91 or more days in arrears	4,041	4,322	4,818
40	Total arrears balance of program participants	$972,232.00	$805,965.43	$779,150.05
41	31 – 60 days in arrears	$275,528.81	$202,161.92	$182,346.61
42	61 – 90 days in arrears	$239,722.27	$177,425.70	$142,671.84
43	91 or more days in arrears	$456,980.92	$426,377.81	$454,131.60

Appendix

Appendix Table 1: Utility Bill Discount Program Information

Line No.	Utility Bill Discount Tier *Note: NW Natural's Tiers are numbered 0-4.	SMI Range (%)	Discount (%)
1	Tier 1	46% - 60% SMI	15%
2	Tier 2	31% - 45% SMI	20%
3	Tier 3	16% - 30% SMI	25%
4	Tier 4	0% - 15% SMI	40%
5	Tier 5		

Appendix Table 2: Terms & Definitions

Line No.	Term	Definition
1	Administrative costs	All incremental expenses related to the management and operation of the bill discount program. This includes, but is not limited to, incremental costs for program design, staff salaries, data processing, customer outreach, eligibility verification, compliance, reporting, and any other overhead or indirect costs necessary to administer the program
2	Applied credits	The aggregate dollar value of discounts applied to the utility bills of residential customers that participate in the utility's bill discount program.
3	Arrearage balance	Any amount of money that a customer owes to the utility company for services provided which remain unpaid past the bill issuance date.
4	Average bill discount program participant usage	The average monthly usage of residential customers enrolled in a utility- administered bill discount program.
5	Average residential bill	The average monthly bill for residential utility services within a utility's Oregon service territory
6	Average residential usage	The average monthly amount of energy billed per residential meter within a utility's Oregon service territory.
7	Disenrollments	Residential customers who were enrolled in a utility's bill discount program as of the previous reporting period but are no longer participating as of the current reporting period. This includes customers who were removed from the program due to ineligibility or non-compliance.
8	Energy assistance recipient	A residential customer who has received bill payment assistance with an energy bill from any federal, state, customer-funded, bill payment assistance fund or program at least once within the past 12 months.
9	New enrollments	Residential customers enrolled in a utility's bill discount program for the first time within the current calendar year.
10	Pre-discount average bill discount program participant bill	The average monthly utility bill amount for bill discount program participants before the application of any bill discounts.
11	Post-discount average bill discount program participant bill	The average monthly utility bill amount for bill discount program participants after the application of their respective bill discount.
12	Residential customer	Any individual or household that receives utility services for personal, non- commercial use. This includes all customers being served on a utility's residential service tariff.
13	Service disconnection for non-payment	Any instances where utility service to a residential account was terminated due to the customer's failure to pay their utility bill.
14	Disconnection notice	Any written or electronic notification issued by a utility to a customer in accordance with OAR 860-021-0405 (3).
15	Total arrears balance of bill discount program participants	The total dollar amount of outstanding balances owed by residential customers enrolled in a utility-administered bill discount program on their utility bills.
16	Total dollars provided to bill discount program participants	The aggregate dollar value of discounts applied to the utility bills of residential customers who participate in the utility's bill discount program.
17	Total bill discount program costs	The total expenditure incurred by a utility in administering its bill discount program for low-income residential customers.
18	Total residential arrearage balances	The total dollar amount of outstanding balances owed by residential customers on their utility bills.
19	31-60 days in arrears	A customer who has an arrearage balance that has been unpaid for a period of between 31 and 60 days from the original bill issuance date.
20	61-90 days in arrears	A customer who has an arrearage balance that has been unpaid for a period of between 61 and 90 days from the original bill issuance date.
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OREGON PUBLIC UTILITY COMMISSION
ENERGY BURDEN METRICS REPORT QUARTERLY REPORT
DOCKET NO. RO 16
OAR 860-021-0408

Instructions for Filing

General Information

I. Purpose

The Energy Burden Metrics Report is a quarterly reporting requirement for all investor-owned utilities that operate within Oregon. These reports are designed to collect energy burden related metrics and program specific information from utilities. These reports are considered to be non-confidential.

II. Who Must Submit

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f. For all residential arrearage figures, each residential customer should only be counted only in one group, based on their oldest arrearage balance.
g. If errors or omissions are discovered after a report has been submitted, utilities must submit a revised report within 30 days of identifying the discrepancy.
h. In addition to this form, utilities must submit zip-code level data in an accompanying excel file.

Table 1: Utility Information

Line No.	Field	Description
1	Utility Name	NW Natural
2	Reporting Period	4Q24
3	Date of Submission	8/14/2025

Table 2: Arrearage Information

Line No.	Metric	Month 1	Month 2	Month 3
		Oct-24	Nov-24	Dec-24
1	Total Number of Residential Customers in Arrears	55,356	57,337	51,517
2	31 – 60 days in arrears	22,312	25,518	22,145
3	61 – 90 days in arrears	9,889	10,177	10,492
4	91 or more days in arrears	23,155	21,642	18,880
5	Total Residential Arrears Balance	$4,048,138	$4,295,214	$5,436,400
6	31 – 60 days in arrears	$1,378,168	$2,037,101	$3,136,505
7	61 – 90 days in arrears	$688,914	$685,053	$946,581
8	91 or more days in arrears	$1,981,056	$1,573,061	$1,353,314
9	Total number of customers enrolled in Time Payment Arrangements (TPA) or other extended payment plans	7,857	7,209	6,655

Table 3: Disconnection Information				
Line No.	**Metric**	**Month 1**	**Month 2**	**Month 3**
		Oct-24	Nov-24	Dec-24
1	Total number of active residential accounts	645,109	645,848	647,425
2	Total number of service disconnections for non-payment	872	646	400
3	Total number of disconnection notices sent to residential customers	9,477	7,974	20,286
4	Percentage of accounts with service disconnections for non-payment	0.14%	0.06%	0.07%
5	Total number of bill discount recipient service disconnections for non- payment	427	282	135
6	Total number of energy assistance recipient service disconnections for non- payment	26	9	11
7	Total number of service disconnections for non-payment on medical certificate holder accounts	1	4	0
8	Number of service reconnections following a service disconnection for non- payment on the same day or next calendar day following disconnection	272	238	156
9	Number of service reconnections following a service disconnection for non- payment that occur more than one day and within 7 calendar days following disconnection	229	158	69
10	Number of days on which the energy utility was required to impose a moratorium on service disconnection for severe weather as required by OAR 860-021-0407 (Severe Weather Moratorium on Involuntary Disconnection of Residential Electric or Gas Utility Service)*	1	4	8

*Reported maximum number of days in NW Natural's service territory. Details are in the accompanying data file.

Table 4: Usage and Bill Information				
Line No.	Metric	Month 1	Month 2	Month 3
		Oct-24	Nov-24	Dec-24
1	Total residential usage	12,408,086.00	31,422,253.40	61,198,420.30
2	Average residential usage	13.26	19.21	48.60
3	Average residential bill	$26.09	$33.82	$73.34

Section 5: Bill Discount Program Information				
Line No.	Metric	Month 1	Month 2	Month 3
		Oct-24	Nov-24	Dec-24
1	Total number of residential customers which received a bill discount	43,418	42,839	42,298
2	Tier 1	12156	10861	10,999
3	Tier 2	12,518	5,660	13,127
4	Tier 3	11,224	11,607	11,533
5	Tier 4	7,520	14,711	7,639
6	Tier 5			
7	Total dollars provided to bill discount program participants	$332,625.00	$1,145,455.54	$2,353,805.28
8	Tier 1	$58,214.70	$110,982.54	$216,993.93
9	Tier 2	$83,381.21	$60,087.70	$535,505.65
10	Tier 3	$92,510.43	$265,701.73	$762,586.98
11	Tier 4	$98,518.66	$708,683.57	$838,718.72
12	Tier 5			
13	Total bill discount program costs			
14	Incremental administrative costs			$6,179.95
15	Applied credits	$332,625.00	$1,145,455.54	$2,353,805.28
16	Total number of new enrollments	3,100	1433	1744
17	Total number of disenrollments	3771	936	994
18	Average bill discount program participant usage			
19	Tier 1	17.62	44.58	88.35
20	Tier 2	18.78	29.73	91.83
21	Tier 3	18.54	40.86	88.96
22	Tier 4	18.32	49.92	86.57
23	Tier 5			
24	Pre-discount average bill discount program participant bill			
25	Tier 1	$32.97	$69.13	$133.51
26	Tier 2	$34.65	$80.06	$137.78
27	Tier 3	$34.09	$77.93	$134.01
28	Tier 4	$35.14	$75.51	$130.89
29	Tier 5			
30	Post-discount average bill discount program participant bill			
31	Tier 1	$28.18	$59.11	$113.78
32	Tier 2	$27.99	$56.40	$96.95
33	Tier 3	$25.85	$39.71	$67.89
34	Tier 4	$22.04	$12.37	$21.10
35	Tier 5			
36	Total number of bill discount program participants with an arrearage balance	9,660	9,486	9,522
37	31 – 60 days in arrears	2,798	2,981	2,791
38	61 – 90 days in arrears	1,659	1,849	2,015
39	91 or more days in arrears	5,203	4,656	4,716
40	Total arrears balance of program participants	$812,084.55	$812,826.97	$946,565.91
41	31 – 60 days in arrears	$217,209.30	$301,409.47	$396,906.53
42	61 – 90 days in arrears	$132,521.40	$133,586.68	$210,467.95
43	91 or more days in arrears	$462,353.85	$377,830.82	$339,191.43

Appendix

Appendix Table 1: Utility Bill Discount Program Information

Line No.	Utility Bill Discount Tier *Note: NW Natural's Tiers are numbered 0-4. NW Natural changed discount tiers on November 1, 2024	SMI Range (%)	Discount (%)
1	Tier 1	46% - 60% SMI	15%
2	Tier 2	31% - 45% SMI	20% through 10/31/2024; 30% 11/1/24 forward
3	Tier 3	16% - 30% SMI	25% through 10/31/2024; 50% 11/1/24 forward
4	Tier 4	0% - 15% SMI	40% through 10/31/2024; 85% 11/1/24 forward
5	Tier 5		

Appendix Table 2: Terms & Definitions

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17	Total bill discount program costs	The total expenditure incurred by a utility in administering its bill discount program for low-income residential customers.
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Table 1: Utility Information

Line No.	Field	Description
1	Utility Name	NW Natural
2	Reporting Period	1Q25
3	Date of Submission	8/14/2025

Table 2: Arrearage Information

Line No.	Metric	Month 1	Month 2	Month 3
		Jan-25	Feb-25	Mar-25
1	Total Number of Residential Customers in Arrears	48,660	54,496	50,248
2	31 – 60 days in arrears	25,557	33,556	24,018
3	61 – 90 days in arrears	8,808	9,210	15,805
4	91 or more days in arrears	14,295	11,730	10,425
5	Total Residential Arrears Balance	$7,132,971	$8,110,502	$7,549,450
6	31 – 60 days in arrears	$4,924,090	$5,706,013	$4,978,082
7	61 – 90 days in arrears	$1,100,364	$1,361,286	$1,505,821
8	91 or more days in arrears	$1,108,516	$1,043,204	$1,065,546
9	Total number of customers enrolled in Time Payment Arrangements (TPA) or other extended payment plans	6,377	6,642	6,865

Table 3: Disconnection Information				
Line No.	**Metric**	**Month 1**	**Month 2**	**Month 3**
		Jan-25	Feb-25	Mar-25
1	Total number of active residential accounts	648,145	648,230	648,494
2	Total number of service disconnections for non-payment	462	899	1527
3	Total number of disconnection notices sent to residential customers	37,611	38,313	37,424
4	Percentage of accounts with service disconnections for non-payment	0.07%	0.14%	0.24%
5	Total number of bill discount recipient service disconnections for non- payment	153	253	421
6	Total number of energy assistance recipient service disconnections for non- payment	0	0	2
7	Total number of service disconnections for non-payment on medical certificate holder accounts	0	0	1
8	Number of service reconnections following a service disconnection for non- payment on the same day or next calendar day following disconnection	194	316	504
9	Number of service reconnections following a service disconnection for non- payment that occur more than one day and within 7 calendar days following disconnection	83	235	379
10	Number of days on which the energy utility was required to impose a moratorium on service disconnection for severe weather as required by OAR 860-021-0407 (Severe Weather Moratorium on Involuntary Disconnection of Residential Electric or Gas Utility Service)*	15	9	4

*Reported maximum number of days in NW Natural's service territory. Details are in the accompanying data file.

Table 4: Usage and Bill Information				
Line No.	Metric	Month 1	Month 2	Month 3
		Jan-25	Feb-25	Mar-25
1	Total residential usage	65,339,313.90	71,154,074.80	47,825,333.40
2	Average residential usage	100.7	109.65	73.68
3	Average residential bill	$153.72	$136.73	$116.71

Section 5: Bill Discount Program Information				
Line No.	Metric	Month 1	Month 2	Month 3
		Jan-25	Feb-25	Mar-25
1	Total number of residential customers which received a bill discount	44,437	45,083	45,633
2	Tier 1	11,648	12,121	12,242
3	Tier 2	13,431	13,545	13,733
4	Tier 3	11,585	11,595	11,728
5	Tier 4	7,773	7,822	7,930
6	Tier 5			
7	Total dollars provided to bill discount program participants	$2,638,820.10	$2,377,697.52	$2,083,554.02
8	Tier 1	$252,322.11	$234,739.10	$204,144.86
9	Tier 2	$601,211.67	$540,352.49	$471,019.95
10	Tier 3	$840,963.07	$750,347.42	$656,574.41
11	Tier 4	$944,323.25	$852,258.51	$751,814.80
12	Tier 5			
13	Total bill discount program costs			
14	Incremental administrative costs	$0.00	$0.00	$9,000.00
15	Applied credits	$2,638,820.10	$2,377,697.52	$2,083,554.02
16	Total number of new enrollments	2,192	1755	1640
17	Total number of disenrollments	1316	1550	1542
18	Average bill discount program participant usage			
19	Tier 1	93.54	103.26	68.86
20	Tier 2	97.16	106.48	71.33
21	Tier 3	94.10	103.64	69.52
22	Tier 4	92.46	102.30	69.35
23	Tier 5			
24	Pre-discount average bill discount program participant bill			
25	Tier 1	$145.93	$130.63	$112.53
26	Tier 2	$151.02	$134.66	$115.79
27	Tier 3	$147.23	$131.37	$114.18
28	Tier 4	$145.89	$130.65	$113.71
29	Tier 5			
30	Post-discount average bill discount program participant bill			
31	Tier 1	$124.27	$111.27	$95.86
32	Tier 2	$106.26	$94.77	$81.49
33	Tier 3	$74.64	$66.65	$58.19
34	Tier 4	$24.41	$21.70	$18.91
35	Tier 5			
36	Total number of bill discount program participants with an arrearage balance	9,963	10,466	10,190
37	31 – 60 days in arrears	3,744	4,143	3,845
38	61 – 90 days in arrears	2,049	2,658	3,054
39	91 or more days in arrears	4,170	3,665	3,291
40	Total arrears balance of program participants	$1,269,450.69	$1,522,772.74	$1,453,345.96
41	31 – 60 days in arrears	$719,966.55	$867,654.58	$767,314.66
42	61 – 90 days in arrears	$243,243.17	$360,752.34	$388,700.57
43	91 or more days in arrears	$306,240.97	$294,365.82	$297,330.73

Appendix

Appendix Table 1: Utility Bill Discount Program Information

Line No.	Utility Bill Discount Tier *Note: NW Natural's Tiers are numbered 0-4.	SMI Range (%)	Discount (%)
1	Tier 1	46% - 60% SMI	15%
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3	Tier 3	16% - 30% SMI	50%
4	Tier 4	0% - 15% SMI	85%
5	Tier 5		

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17	Total bill discount program costs	The total expenditure incurred by a utility in administering its bill discount program for low-income residential customers.
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20	61-90 days in arrears	A customer who has an arrearage balance that has been unpaid for a period of between 61 and 90 days from the original bill issuance date.
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Table 1: Utility Information

Line No.	Field	Description
1	Utility Name	NW Natural
2	Reporting Period	2Q25
3	Date of Submission	8/14/2025

Table 2: Arrearage Information

Line No.	Metric	Month 1	Month 2	Month 3
		Apr-25	May-25	Jun-25
1	Total Number of Residential Customers in Arrears	50,388	55,870	51,119
2	31 – 60 days in arrears	29,269	29,751	22,658
3	61 – 90 days in arrears	9,138	13,289	13,958
4	91 or more days in arrears	11,981	12,830	14,503
5	Total Residential Arrears Balance	$6,824,381	$7,030,486	$5,219,814
6	31 – 60 days in arrears	$4,299,177	$3,721,189	$1,994,400
7	61 – 90 days in arrears	$1,297,977	$1,751,054	$1,476,520
8	91 or more days in arrears	$1,227,226	$1,558,242	$1,748,894
9	Total number of customers enrolled in Time Payment Arrangements (TPA) or other extended payment plans	7,523	6,594	7,693

Table 3: Disconnection Information				
Line No.	**Metric**	**Month 1**	**Month 2**	**Month 3**
		Apr-25	May-25	Jun-25
1	Total number of active residential accounts	649,069	582,000	649,110
2	Total number of service disconnections for non-payment	1803	999	1426
3	Total number of disconnection notices sent to residential customers	31,324	25,207	13,130
4	Percentage of accounts with service disconnections for non-payment	0.28%	0.17%	0.22%
5	Total number of bill discount recipient service disconnections for non- payment	536	336	539
6	Total number of energy assistance recipient service disconnections for non- payment	5	6	14
7	Total number of service disconnections for non-payment on medical certificate holder accounts	0	3	2
8	Number of service reconnections following a service disconnection for non- payment on the same day or next calendar day following disconnection	585	347	376
9	Number of service reconnections following a service disconnection for non- payment that occur more than one day and within 7 calendar days following disconnection	370	299	25
10	Number of days on which the energy utility was required to impose a moratorium on service disconnection for severe weather as required by OAR 860-021-0407 (Severe Weather Moratorium on Involuntary Disconnection of Residential Electric or Gas Utility Service)*	0	0	0

*Reported maximum number of days in NW Natural's service territory. Details are in the accompanying data file.

Table 4: Usage and Bill Information				
Line No.	Metric	Month 1	Month 2	Month 3
		Apr-25	May-25	Jun-25
1	Total residential usage	32,838,371.60	17,505,873.70	13,710,337.40
2	Average residential usage	50.55	30.06	20.11
3	Average residential bill	$86.96	$55.48	$39.75

Section 5: Bill Discount Program Information				
Line No.	Metric	Month 1	Month 2	Month 3
		Apr-25	May-25	Jun-25
1	Total number of residential customers which received a bill discount	46,251	39,548	46,395
2	Tier 1	12,581	10,895	12,586
3	Tier 2	13,836	11,968	13,895
4	Tier 3	11,784	9,939	11,812
5	Tier 4	8,050	6,746	8,102
6	Tier 5			
7	Total dollars provided to bill discount program participants	$1,584,634.29	$864,802.68	$754,071.96
8	Tier 1	$156,662.47	$86,088.60	$72,697.22
9	Tier 2	$355,676.25	$196,120.10	$164,268.29
10	Tier 3	$494,472.52	$270,189.85	$233,867.41
11	Tier 4	$577,823.05	$312,404.13	$283,239.04
12	Tier 5			
13	Total bill discount program costs			
14	Incremental administrative costs	$0.00	$0.00	$0.00
15	Applied credits	$1,584,634.29	$864,802.68	$754,071.96
16	Total number of new enrollments	1,563	1212	1115
17	Total number of disenrollments	1424	1431	1110
18	Average bill discount program participant usage			
19	Tier 1	47.58	13.00	20.08
20	Tier 2	49.62	13.40	20.75
21	Tier 3	48.24	13.41	20.81
22	Tier 4	48.61	14.21	22.14
23	Tier 5			
24	Pre-discount average bill discount program participant bill			
25	Tier 1	$84.55	$53.63	$39.67
26	Tier 2	$87.31	$55.69	$40.48
27	Tier 3	$85.73	$55.66	$41.09
28	Tier 4	$79.53	$49.94	$34.86
29	Tier 5			
30	Post-discount average bill discount program participant bill			
31	Tier 1	$72.10	$45.73	$33.89
32	Tier 2	$61.60	$39.30	$28.66
33	Tier 3	$43.77	$28.48	$21.29
34	Tier 4	$7.75	$3.63	-$0.10
35	Tier 5			
36	Total number of bill discount program participants with an arrearage balance	10,457	8,994	9,835
37	31 – 60 days in arrears	4,040	3,241	2,577
38	61 – 90 days in arrears	2,982	2,651	2,964
39	91 or more days in arrears	3,435	3,102	4,294
40	Total arrears balance of program participants	$1,361,747.73	$1,083,521.98	$984,640.74
41	31 – 60 days in arrears	$683,611.73	$461,563.96	$271,013.83
42	61 – 90 days in arrears	$357,086.30	$315,472.88	$292,501.81
43	91 or more days in arrears	$321,049.70	$306,485.14	$421,125.10

Appendix

Appendix Table 1: Utility Bill Discount Program Information

Line No.	Utility Bill Discount Tier *Note: NW Natural's Tiers are numbered 0-4.	SMI Range (%)	Discount (%)
1	Tier 1	46% - 60% SMI	15%
2	Tier 2	31% - 45% SMI	30%
3	Tier 3	16% - 30% SMI	50%
4	Tier 4	0% - 15% SMI	85%
5	Tier 5		

Appendix Table 2: Terms & Definitions

Line No.	Term	Definition
1	Administrative costs	All incremental expenses related to the management and operation of the bill discount program. This includes, but is not limited to, incremental costs for program design, staff salaries, data processing, customer outreach, eligibility verification, compliance, reporting, and any other overhead or indirect costs necessary to administer the program
2	Applied credits	The aggregate dollar value of discounts applied to the utility bills of residential customers that participate in the utility's bill discount program.
3	Arrearage balance	Any amount of money that a customer owes to the utility company for services provided which remain unpaid past the bill issuance date.
4	Average bill discount program participant usage	The average monthly usage of residential customers enrolled in a utility- administered bill discount program.
5	Average residential bill	The average monthly bill for residential utility services within a utility's Oregon service territory
6	Average residential usage	The average monthly amount of energy billed per residential meter within a utility's Oregon service territory.
7	Disenrollments	Residential customers who were enrolled in a utility's bill discount program as of the previous reporting period but are no longer participating as of the current reporting period. This includes customers who were removed from the program due to ineligibility or non-compliance.
8	Energy assistance recipient	A residential customer who has received bill payment assistance with an energy bill from any federal, state, customer-funded, bill payment assistance fund or program at least once within the past 12 months.
9	New enrollments	Residential customers enrolled in a utility's bill discount program for the first time within the current calendar year.
10	Pre-discount average bill discount program participant bill	The average monthly utility bill amount for bill discount program participants before the application of any bill discounts.
11	Post-discount average bill discount program participant bill	The average monthly utility bill amount for bill discount program participants after the application of their respective bill discount.
12	Residential customer	Any individual or household that receives utility services for personal, non- commercial use. This includes all customers being served on a utility's residential service tariff.
13	Service disconnection for non-payment	Any instances where utility service to a residential account was terminated due to the customer's failure to pay their utility bill.
14	Disconnection notice	Any written or electronic notification issued by a utility to a customer in accordance with OAR 860-021-0405 (3).
15	Total arrears balance of bill discount program participants	The total dollar amount of outstanding balances owed by residential customers enrolled in a utility-administered bill discount program on their utility bills.
16	Total dollars provided to bill discount program participants	The aggregate dollar value of discounts applied to the utility bills of residential customers who participate in the utility's bill discount program.
17	Total bill discount program costs	The total expenditure incurred by a utility in administering its bill discount program for low-income residential customers.
18	Total residential arrearage balances	The total dollar amount of outstanding balances owed by residential customers on their utility bills.
19	31-60 days in arrears	A customer who has an arrearage balance that has been unpaid for a period of between 31 and 60 days from the original bill issuance date.
20	61-90 days in arrears	A customer who has an arrearage balance that has been unpaid for a period of between 61 and 90 days from the original bill issuance date.
21	91+ days in arrears	A customer who has an arrearage balance that has been unpaid for a period greater than 90 days from the original bill issuance date.

Oregon Public Utility Commission

e-FILING REPORT COVER SHEET

COMPANY NAME: NW Natural

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☒ No ☐ Yes If yes, submit a redacted public version (or a cover letter) by email. Submit the confidential information as directed in OAR 860-001-0070 or the terms of an applicable protective order.

Select report type: ☐ RE (Electric) ☐ RG (Gas) ☐ RW (Water) ☐ RT (Telecommunications)
☐ RO (Other, for example, industry safety information)

Did you previously file a similar report? ☐ No ☐ Yes, report docket number:

Report is required by: ☐ OAR
☐ Statute
☐ Order
Note: A one-time submission required by an order is a compliance filing and not a report (file compliance in the applicable docket)
☐ Other
(For example, federal regulations, or requested by Staff)

Is this report associated with a specific docket/case? ☐ No ☐ Yes, docket number:

List Key Words for this report. We use these to improve search results.

Send the completed Cover Sheet and the Report in an email addressed to PUC.FilingCenter@state.or.us

Send confidential information, voluminous reports, or energy utility Results of Operations Reports to PUC Filing Center, PO Box 1088, Salem, OR 97308-1088 or by delivery service to 201 High Street SE Suite 100, Salem, OR 97301.

NW Natural®

250 SW Taylor Street
Portland, OR 97204

503-226-4211
nwnatural.com

November 17, 2025

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
Post Office Box 1088
Salem, OR 97308-1088

Re: RO 16 – Energy Burden Metrics Report OAR 860-021-0408

In compliance with OAR 860-021-0408, Northwest Natural Gas Company, dba NW Natural, submits the enclosed Energy Burden Metrics Report for the third quarter 2025, using the template provided by Public Utility Commission of Oregon Staff.

Please address correspondence on this matter to me with copies to the following:

eFiling
Rates & Regulatory Affairs
NW Natural
250 SW Taylor Street
Portland, Oregon 97204
Telephone: (503) 610-7330
Fax: (503) 220-2579
Email: eFiling@nwnatural.com

Sincerely,

/s/ Natasha Siores

Natasha Siores
Senior Manager, Regulatory Affairs
NW Natural
250 SW Taylor Street
Portland, OR 97204
Telephone: (503) 610- 7074
Email: natasha.siores@nwnatural.com

Enclosures

cc: Bret Farrell

Oregon Public Utility Commission

Docket No. RO 16 - Energy Burden Metrics Report

Table 1: Utility Information

Line No.	Field	Response
1	Utility Name	NW Natural
2	Reporting Period	Third Quarter 2025
3	Date of Submission	November 17, 2025

Table 2: Arrearage Information

Line No.	**Month**	July	August	September
	Year	2025	2025	2025
1	Total Customers in Arrears	53,545.00	57,725.00	55,982.00
2	31-60 Days in Arrears	25,875.00	25,060.00	22,018.00
3	61-90 Days in Arrears	10,218.00	13,714.00	12,024.00
4	91 or More Days in Arrears	17,452.00	18,951.00	21,940.00
5	Total Arrears Balance	$ 4,450,767.41	$ 4,204,896.41	$ 3,791,976.07
6	31-60 Days in Arrears	$ 1,833,140.78	$ 1,555,281.07	$ 1,319,720.46
7	61-90 Days in Arrears	$ 813,701.40	$ 964,133.63	$ 796,477.84
8	91 or More Days in Arrears	$ 1,803,925.23	$ 1,685,481.71	$ 1,675,777.77
9	Total number of customers enrolled in Time Payment Arrangements (TPA) or other extended payment plans	7,477.00	1,685,481.71	6,817.00

Table 3: Disconnection Information

Line No.	**Month**	July	August	September
	Year	2025	2025	2025
1	Total number of active residential accounts	648,638.00	648,421.00	648,036.00
2	Total number of service disconnections for non-payment	1,594.00	1,023.00	826.00
3	Percentage of accounts with service disconnections for non-payment	0%	0%	0%
4	Total number of disconnection notices sent to residential customers	12,181.00	7,664.00	7,139.00
5	Total number of bill discount recipient service disconnections for non payment	614.00	436.00	327.00
6	Total number of energy assistance recipient service disconnections for non payment	90.00	57.00	43.00
7	Total number of service disconnections for non-payment on medical certificate holder accounts	1.00	2.00	-

Table 3 Continued: Disconnection Information

Line No.	**Month**	July	August	September
	Year	2025	2025	2025
8	Number of service reconnections following a service disconnection for non payment on the same day or next calendar day following disconnection	447.00	329.00	310.00
9	Number of service reconnections following a service disconnection for non payment that occur more than one day and within 7 calendar days following disconnection	299.00	201.00	199.00
10	Number of days on which the energy utility was required to impose a moratorium on service disconnection for severe weather as required by OAR 860-021-0407	-	-	-

Table 4: Usage and Bill Information

Line No.	**Month**	July	August	September
	Year	2,025	2,025	2,025
1	Total Residential Usage	9,205,751.20	7,454,007.60	7,740,914.30
2	Average Residential Usage	14.18	11.49	11.94
3	Average Residential Bill	$ 31.10	$ 27.50	$ 28.12

Table 5: Bill Discount Program Information

Line No.	**Month**	July	August	September
	Year	2,025	2,025	2,025
1	Total number of residential customers which received a bill discount	46,268.00	46,007.00	46,107.00
2	Tier 1	12,461.00	12,197.00	12,194.00
3	Tier 2	13,893.00	13,840.00	13,921.00
4	Tier 3	11,818.00	11,850.00	11,843.00
5	Tier 4	8,096.00	8,120.00	8,149.00
6	Tier 5	-	-	-
7	Total dollars provided to bill discount program participants	$ 573,975.13	$ 492,952.05	$ 507,901.74
8	Tier 1	$ 55,140.82	$ 46,852.25	$ 47,716.64
9	Tier 2	$ 125,609.13	$ 107,892.08	$ 111,279.91
10	Tier 3	$ 178,779.39	$ 154,290.52	$ 159,052.02
11	Tier 4	$ 214,445.79	$ 183,917.20	$ 189,853.17
12	Tier 5	$ -	$ -	$ -
13	Total bill discount program costs	$ 573,975.13	$ 492,952.05	$ 507,901.74
14	Incremental administrative costs	$ -	$ -	$ -
15	Applied Credits	$ 573,975.13	$ 492,952.05	$ 507,901.74
16	Total number of new enrollments	1,065.00	1,046.00	1,124.00
17	Total number of disenrollments	1,027.00	1,057.00	892.00

Table 5 Continued: Bill Discount Program Information

Line No.	**Month**	July	August	September
	Year	2025	2025	2025
18	Average bill discount program participant usage	13.44	10.82	11.33
19	Tier 1	13.00	10.41	10.84
20	Tier 2	13.40	10.77	11.28
21	Tier 3	13.41	10.85	11.46
22	Tier 4	14.21	11.45	11.94
23	Tier 5	-	-	-
24	Pre-discount average bill discount program participant bill	$ 30.24	$ 26.59	$ 27.73
25	Tier 1	$ 30.41	$ 26.61	$ 26.98
26	Tier 2	$ 31.15	$ 27.03	$ 27.78
27	Tier 3	$ 31.42	$ 27.12	$ 28.82
28	Tier 4	$ 26.71	$ 25.01	$ 27.18
29	Tier 5	$ -	$ -	$ -
30	Post-discount average bill discount program participant bill	$ 17.84	$ 15.87	$ 16.72
31	Tier 1	$ 25.99	$ 22.77	$ 23.07
32	Tier 2	$ 22.11	$ 19.24	$ 19.79
33	Tier 3	$ 16.29	$ 14.10	$ 15.39
34	Tier 4	$ 0.22	$ 2.36	$ 3.89
35	Tier 5	$ -	$ -	$ -

Table 5 Continued: Bill Discount Program Information

Line No.	**Month**	July	August	September
	Year	2025	2025	2025
36	Total number of bill discount program participants with an arrearage balance	10,063.00	10,304.00	9,939.00
37	31-60 Days in Arrears	3,235.00	2,927.00	2,649.00
38	61-90 Days in Arrears	1,767.00	2,403.00	1,947.00
39	91 or More Days in Arrears	5,061.00	4,974.00	5,343.00
40	Total arrears balance of program participants	$ 835,116.99	$ 728,684.09	$ 625,097.97
41	31-60 Days in Arrears	$ 253,359.63	$ 194,844.12	$ 168,799.13
42	61-90 Days in Arrears	$ 149,614.94	$ 167,239.74	$ 124,233.51
43	91 or More Days in Arrears	$ 432,142.42	$ 366,600.23	$ 332,065.33

Appendix Table 1: Utility Bill Discount Program Information

LINE NO.	Utility Bill Discount Tier	SMI Range (%)	Discount
1	Tier 1	46% - 60% SMI	15%
2	Tier 2	31% - 45% SMI	30%
3	Tier 3	16% - 30% SMI	50%
4	Tier 4	0% - 15% SMI	85%
5	0	0	0

Oregon Public Utility Commission

e-FILING REPORT COVER SHEET

COMPANY NAME: NW Natural

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☐ No ☐ Yes If yes, submit a redacted public version (or a cover letter) by email. Submit the confidential information as directed in OAR 860-001-0070 or the terms of an applicable protective order.

Select report type: ☐ RE (Electric) ☐ RG (Gas) ☐ RW (Water) ☐ RT (Telecommunications)
☐ RO (Other, for example, industry safety information)

Did you previously file a similar report? ☐ No ☐ Yes, report docket number:

Report is required by: ☐ OAR
☐ Statute
☐ Order
Note: A one-time submission required by an order is a compliance filing and not a report (file compliance in the applicable docket)
☐ Other
(For example, federal regulations, or requested by Staff)

Is this report associated with a specific docket/case? ☐ No ☐ Yes, docket number:

List Key Words for this report. We use these to improve search results.

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Send confidential information, voluminous reports, or energy utility Results of Operations Reports to PUC Filing Center, PO Box 1088, Salem, OR 97308-1088 or by delivery service to 201 High Street SE Suite 100, Salem, OR 97301.

NW Natural®

250 SW Taylor Street
Portland, OR 97204

503-226-4211
nwnatural.com

January 29, 2026

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
Post Office Box 1088
Salem, OR 97308-1088

Re: RO 16 – Energy Burden Metrics Report OAR 860-021-0408

In compliance with OAR 860-021-0408, Northwest Natural Gas Company, dba NW Natural, submits the enclosed Energy Burden Metrics Report for the fourth quarter 2025, using the template provided by Public Utility Commission of Oregon Staff.

Please address correspondence on this matter to me with copies to the following:

eFiling
Rates & Regulatory Affairs
NW Natural
250 SW Taylor Street
Portland, Oregon 97204
Telephone: (503) 610-7330
Fax: (503) 220-2579
Email: eFiling@nwnatural.com

Sincerely,

/s/ Natasha Siores

Natasha Siores
Senior Manager, Regulatory Affairs
NW Natural
250 SW Taylor Street
Portland, OR 97204
Telephone: (503) 610- 7074
Email: natasha.siores@nwnatural.com

Enclosures

cc: Bret Farrell

RO 16 - NWN 4Q 2025 Energy Burden Metrics Report

Oregon Public Utility Commission

Docket No. RO 16 - Energy Burden Metrics Report

Table 1: Utility Information

Line No.	Field	Response
1	Utility Name	NW Natural
2	Reporting Period	Fourth Quarter 2025
3	Date of Submission	

Table 2: Arrearage Information

Line No.	**Month**	October	November	December
	Year	2025	2025	2025
1	Total Customers in Arrears	54,805.00	59,813.00	50,279.00
2	31-60 Days in Arrears	22,198.00	26,762.00	21,615.00
3	61-90 Days in Arrears	10,161.00	10,695.00	10,121.00
4	91 or More Days in Arrears	22,446.00	22,356.00	18,543.00
5	Total Arrears Balance	$ 3,555,503.26	$ 4,419,369.14	$ 4,929,100.62
6	31-60 Days in Arrears	$ 1,385,986.29	$ 2,343,450.91	$ 2,922,085.62
7	61-90 Days in Arrears	$ 676,364.66	$ 742,516.18	$ 905,117.83
8	91 or More Days in Arrears	$ 1,493,152.31	$ 1,333,402.05	$ 1,101,897.17
9	Total number of customers enrolled in Time Payment Arrangements (TPA) or other extended payment plans	6,386.00	1,333,402.05	5,586.00

RO 16 - NWN 4Q 2025 Energy Burden Metrics Report

Table 3: Disconnection Information

Line No.	**Month**	October	November	December
	Year	2025	2025	2025
1	Total number of active residential accounts	648,125.00	649,408.00	650,437.00
2	Total number of service disconnections for non-payment	706.00	404.00	694.00
3	Percentage of accounts with service disconnections for non-payment	0.109%	0.062%	0.107%
4	Total number of disconnection notices sent to residential customers	6,658.00	7,302.00	19,865.00
5	Total number of bill discount recipient service disconnections for non-payment	274.00	139.00	213.00
6	Total number of energy assistance recipient service disconnections for non-payment	32.00	14.00	27.00
7	Total number of service disconnections for non-payment on medical certificate holder accounts	-	-	-

Table 3 Continued: Disconnection Information

Line No.	Month	October	November	December
	Year	2025	2025	2025
8	Number of service reconnections following a service disconnection for non-payment on the same day or next calendar day following disconnection	298.00	175.00	325.00
9	Number of service reconnections following a service disconnection for non-payment that occur more than one day and within 7 calendar days following disconnection	154.00	89.00	135.00
10	Number of days on which the energy utility was required to impose a moratorium on service disconnection for severe weather as required by OAR 860-021-0407	-	1.00	7.00

Table 4: Usage and Bill Information

Line No.	Month	October	November	December
	Year	2,025	2,025	2,025
1	Total Residential Usage	13,164,950.30	30,669,393.40	46,672,730.50
2	Average Residential Usage	20.30	47.20	71.73
3	Average Residential Bill	$ 39.32	$ 77.04	$ 123.53

Table 5: Bill Discount Program Information

Line No.	**Month**	October	November	December
	Year	2,025	2,025	2,025
1	Total number of residential customers which received a bill discount	47,295.00	48,027.00	48,662.00
2	Tier 1	11,983.00	12,056.00	12,142.00
3	Tier 2	13,872.00	14,099.00	14,268.00
4	Tier 3	12,797.00	13,037.00	13,245.00
5	Tier 4	8,643.00	8,835.00	9,007.00
6	Tier 5	-	-	-
7	Total dollars provided to bill discount program participants	$ 734,821.32	$ 1,459,765.13	$ 2,393,776.01
8	Tier 1	$ 65,605.24	$ 130,716.71	$ 212,159.57
9	Tier 2	$ 156,458.82	$ 311,920.16	$ 507,845.55
10	Tier 3	$ 237,530.46	$ 472,897.37	$ 773,667.06
11	Tier 4	$ 275,226.80	$ 544,230.89	$ 900,103.83
12	Tier 5	$ -	$ -	$ -
13	Total bill discount program costs	$ 734,821.32	$ 1,459,765.13	$ 2,393,776.01
14	Incremental administrative costs	$ -	$ -	$ -
15	Applied Credits	$ 734,821.32	$ 1,459,765.13	$ 2,393,776.01
16	Total number of new enrollments	1,287.00	1,098.00	1,445.00
17	Total number of disenrollments	891.00	783.00	1,136.00

Table 5 Continued: Bill Discount Program Information

Line No.	**Month**	October	November	December
	Year	2025	2025	2025
18	Average bill discount program participant usage	19.22	44.80	67.98
19	Tier 1	18.71	44.39	67.35
20	Tier 2	19.51	45.42	68.82
21	Tier 3	19.21	44.60	67.56
22	Tier 4	19.46	44.65	68.11
23	Tier 5	-	-	-
24	Pre-discount average bill discount program participant bill	$ 38.27	$ 73.71	$ 118.39
25	Tier 1	$ 37.73	$ 73.82	$ 118.35
26	Tier 2	$ 38.78	$ 75.11	$ 120.32
27	Tier 3	$ 38.79	$ 73.73	$ 118.58
28	Tier 4	$ 37.44	$ 71.29	$ 115.10
29	Tier 5	$ -	$ -	$ -
30	Post-discount average bill discount program participant bill	$ 22.73	$ 43.32	$ 69.20
31	Tier 1	$ 32.25	$ 62.98	$ 100.88
32	Tier 2	$ 27.50	$ 52.99	$ 84.73
33	Tier 3	$ 20.23	$ 37.46	$ 60.16
34	Tier 4	$ 5.60	$ 9.69	$ 15.17
35	Tier 5	$ -	$ -	$ -

Table 5 Continued: Bill Discount Program Information

Line No.	**Month**	October	November	December
	Year	2025	2025	2025
36	Total number of bill discount program participants with an arrearage balance	10,065.00	10,866.00	10,830.00
37	31-60 Days in Arrears	2,895.00	3,484.00	3,223.00
38	61-90 Days in Arrears	1,805.00	1,938.00	2,136.00
39	91 or More Days in Arrears	5,365.00	5,444.00	5,471.00
40	Total arrears balance of program participants	$ 602,826.12	$ 713,389.78	$ 901,710.48
41	31-60 Days in Arrears	$ 183,517.98	$ 292,314.43	$ 431,932.95
42	61-90 Days in Arrears	$ 109,305.24	$ 124,125.36	$ 176,391.72
43	91 or More Days in Arrears	$ 310,002.90	$ 296,949.99	$ 293,385.81

Appendix Table 1: Utility Bill Discount Program Information

LINE NO.	Utility Bill Discount Tier	SMI Range (%)	Discount
1	Tier 1	46% - 60% SMI	15%
2	Tier 2	31% - 45% SMI	30%
3	Tier 3	16% - 30% SMI	50%
4	Tier 4	0% - 15% SMI	85%
5	0	0	0

Oregon Public Utility Commission

e-FILING REPORT COVER SHEET

COMPANY NAME: NW Natural

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ■ No ☐ Yes If yes, submit a redacted public version (or a cover letter) by email. Submit the confidential information as directed in OAR 860-001-0070 or the terms of an applicable protective order.

Select report type: ☐ RE (Electric) ☐ RG (Gas) ☐ RW (Water) ☐ RT (Telecommunications)
☐ RO (Other, for example, industry safety information)

Did you previously file a similar report? ☐ No ☐ Yes, report docket number:

Report is required by: ☐ OAR
☐ Statute
☐ Order
Note: A one-time submission required by an order is a compliance filing and not a report (file compliance in the applicable docket)
☐ Other
(For example, federal regulations, or requested by Staff)

Is this report associated with a specific docket/case? ☐ No ☐ Yes, docket number:

List Key Words for this report. We use these to improve search results.

Send the completed Cover Sheet and the Report in an email addressed to PUC.FilingCenter@state.or.us

Send confidential information, voluminous reports, or energy utility Results of Operations Reports to PUC Filing Center, PO Box 1088, Salem, OR 97308-1088 or by delivery service to 201 High Street SE Suite 100, Salem, OR 97301.

Print

NW Natural®

250 SW Taylor Street
Portland, OR 97204

503-226-4211
nwnatural.com

February 16, 2026

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
Post Office Box 1088
Salem, OR 97308-1088

Re: RO 16 – Energy Burden Metrics Report OAR 860-021-0408

In compliance with OAR 860-021-0408 and Order No. 25-544 issued in docket UM 2211 on December 31, 2025, Northwest Natural Gas Company, dba NW Natural, submits the enclosed Energy Burden Metrics Report for the month of January 2026, using the template provided by Public Utility Commission of Oregon Staff.

Please address correspondence on this matter to me, with copies to the following:

eFiling
Rates & Regulatory Affairs
NW Natural
250 SW Taylor Street
Portland, Oregon 97204
Telephone: (503) 610-7330
Fax: (503) 220-2579
Email: eFiling@nwnatural.com

Sincerely,

/s/ Natasha Siores

Natasha Siores
Senior Manager, Regulatory Affairs
NW Natural
250 SW Taylor Street
Portland, OR 97204
Telephone: (503) 610- 7074
Email: natasha.siores@nwnatural.com

Enclosures

cc: Bret Farrell

RO 16 - NWN Jan 2026 Energy Burden Metrics Report

Oregon Public Utility Commission

Docket No. RO 16 - Energy Burden Metrics Report

Table 1: Utility Information

Line No.	Field	Response
1	Utility Name	NW Natural
2	Reporting Period	January 2026
3	Date of Submission	

Table 2: Arrearage Information

Line No.	**Month**	January	0	0
	Year	2026	2026	2026
1	Total Customers in Arrears	49,811.00	-	-
2	31-60 Days in Arrears	25,915.00	-	-
3	61-90 Days in Arrears	9,316.00	-	-
4	91 or More Days in Arrears	14,580.00	-	-
5	Total Arrears Balance	$ 6,317,486.79	$ -	$ -
6	31-60 Days in Arrears	$ 4,357,047.65	$ -	$ -
7	61-90 Days in Arrears	$ 1,030,640.79	$ -	$ -
8	91 or More Days in Arrears	$ 929,798.35	$ -	$ -
9	Total number of customers enrolled in Time Payment Arrangements (TPA) or other extended payment plans	5,485.00	-	-

RO 16 - NWN Jan 2026 Energy Burden Metrics Report

Table 3: Disconnection Information

Line No.	**Month**	January	0	0
	Year	2026	2026	2026
1	Total number of active residential accounts	650,966.00	-	-
2	Total number of service disconnections for non-payment	833.00	-	-
3	Percentage of accounts with service disconnections for non-payment	0.128%	#DIV/0!	#DIV/0!
4	Total number of disconnection notices sent to residential customers	31,473.00	-	-
5	Total number of bill discount recipient service disconnections for non□payment	233.00	-	-
6	Total number of energy assistance recipient service disconnections for non□payment	24.00	-	-
7	Total number of service disconnections for non-payment on medical certificate holder accounts	-	-	-

RO 16 - NWN Jan 2026 Energy Burden Metrics Report

Table 3 Continued: Disconnection Information

Line No.	**Month**	January	0	0
	Year	2026	2026	2026
8	Number of service reconnections following a service disconnection for non‐payment on the same day or next calendar day following disconnection	420.00	-	-
9	Number of service reconnections following a service disconnection for non‐payment that occur more than one day and within 7 calendar days following disconnection	145.00	-	-
10	Number of days on which the energy utility was required to impose a moratorium on service disconnection for severe weather as required by OAR 860-021-0407	11.00	-	-

Table 4: Usage and Bill Information

Line No.	**Month**	January	0	0
	Year	2,026	2,026	2,026
1	Total Residential Usage	60,250,210.40	-	-
2	Average Residential Usage	92.54	-	-
3	Average Residential Bill	$ 149.60	$ -	$ -

RO 16 - NWN Jan 2026 Energy Burden Metrics Report

Table 5: Bill Discount Program Information

Line No.	**Month**	January	0	0
	Year	2,026	2,026	2,026
1	Total number of residential customers which received a bill discount	49,492.00	-	-
2	Tier 1	12,268.00	-	-
3	Tier 2	14,490.00	-	-
4	Tier 3	13,483.00	-	-
5	Tier 4	9,251.00	-	-
6	Tier 5	-	-	-
7	Total dollars provided to bill discount program participants	$ 2,962,211.25	$ -	$ -
8	Tier 1	$ 261,166.54	$ -	$ -
9	Tier 2	$ 627,413.88	$ -	$ -
10	Tier 3	$ 956,671.83	$ -	$ -
11	Tier 4	$ 1,116,959.00	$ -	$ -
12	Tier 5	$ -	$ -	$ -
13	Total bill discount program costs	$ 2,962,211.25	$ -	$ -
14	Incremental administrative costs	$ -	$ -	$ -
15	Applied Credits	$ 2,962,211.25	$ -	$ -
16	Total number of new enrollments	1,801.00	-	-
17	Total number of disenrollments	1,573.00	-	-

RO 16 - NWN Jan 2026 Energy Burden Metrics Report

Table 5 Continued: Bill Discount Program Information

Line No.	**Month**	January	0	0
	Year	2026	2026	2026
18	Average bill discount program participant usage	88.24	-	-
19	Tier 1	87.71	-	-
20	Tier 2	89.61	-	-
21	Tier 3	87.65	-	-
22	Tier 4	87.65	-	-
23	Tier 5	-	-	-
24	Pre-discount average bill discount program participant bill	$ 143.67	$ -	$ -
25	Tier 1	$ 143.55	$ -	$ -
26	Tier 2	$ 146.32	$ -	$ -
27	Tier 3	$ 144.13	$ -	$ -
28	Tier 4	$ 138.97	$ -	$ -
29	Tier 5	$ -	$ -	$ -
30	Post-discount average bill discount program participant bill	$ 83.81	$ -	$ -
31	Tier 1	$ 122.26	$ -	$ -
32	Tier 2	$ 103.03	$ -	$ -
33	Tier 3	$ 73.18	$ -	$ -
34	Tier 4	$ 18.23	$ -	$ -
35	Tier 5	$ -	$ -	$ -

RO 16 - NWN Jan 2026 Energy Burden Metrics Report

Table 5 Continued: Bill Discount Program Information

Line No.	**Month**	January	0	0
	Year	2026	2026	2026
36	Total number of bill discount program participants with an arrearage balance	11,541.00	-	-
37	31-60 Days in Arrears	4,215.00	-	-
38	61-90 Days in Arrears	2,354.00	-	-
39	91 or More Days in Arrears	4,972.00	-	-
40	Total arrears balance of program participants	$ 1,252,293.00	$ -	$ -
41	31-60 Days in Arrears	$ 712,315.61	$ -	$ -
42	61-90 Days in Arrears	$ 259,849.96	$ -	$ -
43	91 or More Days in Arrears	$ 280,127.43	$ -	$ -

Appendix Table 1: Utility Bill Discount Program Information

LINE NO.	Utility Bill Discount Tier	SMI Range (%)	Discount
1	Tier 1	46% - 60% SMI	15%
2	Tier 2	31% - 45% SMI	30%
3	Tier 3	16% - 30% SMI	50%
4	Tier 4	0% - 15% SMI	85%
5	0	0	0

NW Natural®

Rates & Regulatory Affairs

UG 527

NW Natural Alternative Rate Mechanism

Data Request Response

Request No.: UG 527 CUB DR 7

In the analysis represented by Table 5, "NW Natural Bill Discount Effectiveness Targeting 2 Percent Energy Burden" at NW Natural/100 Kravitz-Walker/Page 20:

a. Why did the Company use the mid-point of income for each tier and not the low-point as a baseline? Did the Company do analysis using the low-point, why or why not?

b. Did the Company consider average winter usage as well as average annual usage in its analysis? Why or why not?

c. Why did the Company use average residential usage in its analysis instead of the average residential usage by tier–which the Company has to now report on in RO 16?

Response:

a. The Company used the mid-point of the income for each tier for consistency and comparability with the actual design of the bill discount program. The Company last proposed changes to the discount percentage in the 2024 rate case in UG 490 (see UG 490 NW Natural/200, Tanka/Pages 22-24). Although the ultimate changes in the discount percentages were resolved through settlement, the underlying analysis included the use of mid-point income levels to provide better coverage of reduced energy burden throughout each tier. The original design of the bill discount program (docket ADV 1390) used the max of the income range. For these reasons, the Company did not analyze using the low-point.

b. No. The analysis provided in Table 5 is consistent with previous illustrations of the impacts of the bill discount program under existing and proposed rates using the same methodology from the program's design, thus providing consistency and comparability of the effectiveness of the program. This analysis used annual usage and annual income. Bill discounts are applied as a percentage of the bill, so larger winter bills will have a commensurately larger bill discount. The bill discount program is intended to reduce energy burden for customers but does not mitigate the seasonality of gas usage. Customers who wish to level out seasonality can participate in the equal pay program.

c. Please refer to responses above – Table 5 uses a methodology previously used in illustrating bill discount program impacts and was used here for consistency and comparability.

Oregon
Tina Kotek, Governor

Public Utility Commission
201 High St SE Suite 100
Salem, OR 97301-3398
Mailing Address: PO Box 1088
Salem, OR 97308-1088
503-373-7394

April 18, 2024

Via Electronic Filing

OREGON PUBLIC UTILITY COMMISSION ATTENTION: FILING CENTER
PO BOX: 1088
SALEM OR 97308-1088

RE: Docket No. UG 490 – In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision.

Attached for Opening Testimony filing are the following exhibits:
Exh 100-109 Muldoon Redacted
Exh 200-202 Mondragon Redacted
Exh 300-301 Scala
Exh 400-402 Nottingham
Exh 500-502 Abraham
Exh 600-601 Anderson
Exh 700-702 Beitzel Redacted
Exh 800-805 Chipanera Redacted
Exh 900-907 Dlouhy Redacted
Exh 1000-1003 Dyck Redacted
Exh 1100-1102 Kim Redacted
Exh 1200-1204 Lockwood
Exh 1300-1303 Moore Redacted
Exh 1400-1402 Peng
Exh 1500-1501 Peterson
Exh 1600-1602 Pileggi
Exh 1700-1704 Rossow
Exh 1800-1803 Shierman
Exh 1900-1901 Stevens
Exh 2000-2004 Yamada Redacted
Exh 2100-2100 Hennessy

Highly Confidential and non-confidential Excel exhibits included with this filing are:
Highly Confidential exhibits:
Exh 2004 (3)

Non-Confidential exhibits:
Exh 101, 102, 103, 104, and 105
Exh 106
Exh 107
Exh 202 (4)
Exh 502
Exh 904
Exh 1002 (5)
Exh 1202
Exh 1203
Exh 2002 (3)

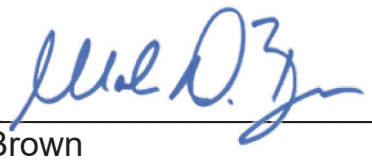
Mark Brown
Oregon Public Utility Commission
(971) 375-5080
mark.brown@puc.oregon.gov

CERTIFICATE OF SERVICE

UG 490

I certify that this day I served the foregoing document upon all the following parties or attorneys of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid or by electronic mail pursuant to OAR 860-001-0180 (which may include a link to a secure shared file service).

Dated this 18th day of April, 2024, at Salem, Oregon.
.



Mark Brown
Public Utility Commission
201 High Street SE, Suite 100
Salem, Oregon 97301-3398
Telephone: (971) 375-5080

UG 490 – Service List

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UG 490 – Service List

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STAFF	
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MATTHEW MULDOON **(C)** **(HC)** PUBLIC UTILITY COMMISSION OF OREGON	PO BOX 1088 SALEM OR 97308-1088 matt.muldoon@puc.oregon.gov

CASE: UG 490
WITNESS: Matt Muldoon

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

REDACTED
OPENING TESTIMONY
Overview and Return on Equity
Subject to Protective Order No. 23-480

April 18, 2024

Docket No: UG 490 Staff/100
Muldoon/1

Q. Please state your name, occupation, and business address.

A. My name is Matt Muldoon. I am a manager employed in the Accounting and Finance Section of the Rates, Safety and Utility Performance Program (RSUP) of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Stipulating Parties/101.

Q. What is the purpose of your testimony?

A. I introduce Staff-sponsored adjustments and issues regarding the Northwest Natural Gas Company (NW Natural, NWN, or Company) request for a general rate revision, docketed as Docket No. UG 490 and articulate some of Staff's overarching concerns regarding the frequency and aggregate magnitude of the Company's proposed increases in this rate case and in recent years. I also address NW Naturals Pensions and Post Retirement Medical Expenses, Cost of Capital components and overall Rate of Return (ROR), going into greater detail regarding Return on Common Equity (ROE).

Further detail on Capital Structure is found in Rose Pileggi's testimony in Exhibit Staff/1200. NW Natural's cost of Long-Term Debt is addressed in a Stipulation executed by Staff and other parties.[1]

Q. Are other Staff witnesses submitting testimony?

A. Yes. Each Staff assigned to Docket No. UG 490 is submitting separate testimony. My testimony introduces the Staff witnesses and their respective

[1] See Stipulating Parties/100, Kravitz, Muldoon, Jenks, Mullins/1-6.

assignments and estimates the revenue requirement impact of Staff recommended adjustments to the Company's initial filing. Additional detail about revenue, expense, and rate base components of Staff's proposed adjustments is found in Luz Mondragon's testimony in Exhibit Staff/200. The issues identified in Staff testimony are those identified to date. Staff's recommendations and issues may change when informed by new data and after reviewing testimony and analysis by other parties.

Q. How is your testimony organized?

A. My testimony is organized as follows:

1. Revenue Requirement Impact by Staff Topic 3
2. Introduction to Other Staff's Opening Testimony 5
3. Concern – Frequency and aggregate Amount of Increases 8
4. Overall Rate of Return (ROR) 14
6. Pensions and Post Retirment Medical Expense 46
7. Physical and Cyber Security 47
8. Conclusion 50

Q. Did you prepare exhibits for this docket?

A. Yes. In addition to my witness qualifications statement, I prepared the following exhibits:

Other Supporting Exhibits

Exhibit Staff/101 .. ROE – Peer Screen, Dividends, EPS, Hamada Adjustments
Exhibit Staff/102 ..... ROE - Three Stage DCF Modeling
Exhibit Staff/103 ..... ROE - Three Stage DCF Modeling Results
Exhibit Staff/104 ..... ROE – Capital Asset Pricing Model (CAPM)
Exhibit Staff/105 ..... ROE – Gordon Growth, Single Stage DCF
Exhibit Staff/106 ..... ROE – US BEA Historical GDP Growth
Exhibit Staff/107 ..... ROE – TIPS Implies Inflation
Exhibit Staff/108 ..... Value Line (VL) Natural Gas and Water Utilities
Exhibit Staff/109 ..... Financial News Investors Are Seeing

Docket No: UG 490

Staff/100
Muldoon/3

1. REVENUE REQUIREMENT IMPACT BY STAFF TOPIC

Q. Please provide a list of the rate case topics that Staff reviewed and introduce the responsible Staff.

A. See Table 1 below:

TABLE 1 – STAFF RATE CASE TOPICS

Staff Issues Summary Table - ($000) for Test Year Ending October 31, 2025					
Total Incremental Revenue Requirement on the Company's Filed General Rate Case				$154,913	$154,913
Exhibit	Issue	Staff	Staff Issues and Proposed Adjustments	Revenue Requirement @ROE 8.9%	Revenue Requirement @ROE 9.3%
100	1	Muldoon	Introduction	-	-
	2		Concerns	-	-
	3		Return on Equity (ROE) - **Range** (Floor to Ceiling)	(18,819)	(12,770)
	4		Pensions and Post Retirement Medical Expense	-	-
	5		Physical and Cyber Security	-	-
200	1	Mondragon	Revenue Requirement Summary	-	-
	2a		Customer Service(CS) , and Operations and Maintenance (O&M) Non-Labor (NL)	(11)	(11)
	2b		Sales Expense Dealer Relations	(88)	(88)
	2c		Sales Expense, Consumer Price Index (CPI) Adjustment	(6)	(6)
	3		ARAM Excess Deferred Income Tax (EDIT)	(140)	(140)
	4		Interest Synchronization	-	-
	6		Budget to Actuals	-	-
300	1	Scala	Energy Justice Overview	-	-
400	1	Nottingham	Overview of Public Comments Received to Date	-	-
	2		How Falling Natural Gas Prices Can Help NWN Customers	-	-
500	1	Abraham	Gas Storage Operating Expense	(275)	(275)
	2		Gas Storage in Rate Base	-	-
	3		New Major Gas Storage Projects	-	-
600	1	Anderson	Utility Plant in Service	-	-
	2		Gains on Sale of Utility Property	-	-
	3		Test Year Rate Base, Discrete vs Non Discrete Investments	-	-
	4		New Major Plant Distribution Projects North Coast Feeder B	(601)	(619)
	5		New Plant - Resource Centers	-	-
	6		Attestations and Other Project Adjustments	-	-
700	1	Beitzel	Non-Medical Insurance and Risk	-	-
	2		Directors and Officers (D&O) Insurance (**CONFIDENTIAL**)	[redacted]	[redacted]
800	1	Chipanera	Escalations	-	-
	2		Cash Working Capital	(45)	(46)
	3		Regulatory Fees	194	194
	4		Income Taxes	-	-
	5		Leasehold Improvements	-	-
	6		Other Related Topics	-	-
900	1	Dlouhy	Climate Protection Program (CPP)	-	-
	2		Renewable Natural Gas Automatic (RNG) Adjustment Clause (AAC)	-	-
	3		Residential Line Extension Allowance (LEA)	-	-
	4		Meter Modernization Program (MMP)	(814)	(841)

Continued on Next Page

Docket No: UG 490

Staff/100
Muldoon/4

1

Concluded

1000	1	Dyck	Information Technology and Security (IT&S) projects, and Cloud-Based Software - Genesis Contingency	**(319)**	**(329)**
	2a		A&G Expense NL, Office Supplies & CPI Adjustment	(975)	(975)
	2b		Admin. Expenses with CPI Adjustment	147	147
	2c		Shareholder Meeting with CPI Adjustment	(287)	(287)
	2d		Rents with CPI Adjusments	(43)	(43)
1100	1	Kim	Long-Term Natural Gas Price Hedging	-	-
	2		Schedule H	-	-
1200	1	Lockwood	Uncollectible Accounts	(2,926)	(2,926)
	2		NW Natural's Bill Discount Program	-	-
1300	1	Moore	Distribution O&M Expense	(6,371)	(6,371)
	2		Materials and Supplies	**(352)**	**(363)**
	3		Customer Accounts	(2,184)	(2,184)
	4		Affiliated Interests	-	-
	5		Atmospheric Testing	-	-
1400	1	Peng	Depreciation Expense	-	-
	2		Ammortization Expense	-	-
	3		Depreciation Reserve	-	-
	4		Ammortization Reserve	-	-
	5		Allowance for Funds Used During Construction (AFUDC)	-	-
1500	1	Peterson	Current Medical and Health Insurance	(542)	(542)
	2		Current Pension Costs	-	-
1600	1	Pileggi	Capital Structure	-	-
1700	1	Rossow	Political Activities and Office Supplies	(12)	(12)
	2		Advertising	(169)	(169)
	3		Memberships Dues and Donations	(499)	(499)
	4		Meals, Entertainment and Travel	(364)	(364)
1800	1	Shierman	Marginal Cost	-	-
	2		Rate Spread	-	-
	3		Rate Design	-	-
1900	1	Stevens	Load Forecasting	-	-
	2		Decoupling	-	-
	3		Rate Base Calculations	-	-
2000	1a	Yamada	Wage and Salaries (W&S) - O&M	(6,657)	(6,657)
	1b		W&S Capital	**(279)**	**(288)**
	2		Incentives	-	-
	3		Full Time Equivalents (FTE)	-	-
	4		Related Issues	-	-
2100	1	Hennessy	Safety and Insepction Programs	-	-
			Total Staff Proposed Adjustments (Base Rates) (**CONFIDENTIAL**):	[redacted]	[redacted]
			Staff-Calculated Revenue Requirements Change (Base Rates) (**CONFIDENTIAL**):	[redacted]	[redacted]

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2. INTRODUCTION TO OTHER STAFF'S OPENING TESTIMONY

Q. Please describe the opening testimony submitted by Staff in this rate case.

A. The Staff exhibit number, respective Staff witness, and topics published on this date are presented below.

Topics addressed in Opening Testimony published April 18, 2024:

In **Exhibit 200, Luz Mondragon**, Senior Financial Analyst, reviews revenue requirements, customer service sales expense, operations and maintenance (O&M) non-labor (NL), excess deferred income taxes, interest synchronization, and budget to actuals.

In **Exhibit 300, Michell Scala**, Energy Justice Program Manager, provides an Energy Justice overview for this general rate case and discusses energy justice foci.

In **Exhibit 400, Melissa Nottingham** summarizes public comments received by the Commission as of March 12, 2024. She also provides an overview of how falling natural gas commodity costs may help control costs in another rate proceeding outside this general rate case: the Company's annual Purchase Gas Adjustment (PGA); and in aggregate reduce total rate increases for changes effective November 1, 2024.

In **Exhibit 500, David Abraham**, Senior Economist, discusses the Company's gas storage operating expense, gas storage in rate base, and new major storage gas projects.

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In **Exhibit 600, Laurel Anderson**, Senior Financial Analyst, discusses utility plant in service, gains on sale of utility property, test year rate base discrete vs, non-discrete investments, new plant major distribution projects, new plant resource centers, attestations, and Staff-proposed project adjustments.

In **Exhibit 700 Russ Beitzel**, Program Manager of the Rates and Telecommunications Section reviews non-medical insurance and risk, and Directors and Officers (D&O) insurance.

In **Exhibit 800, Itayi Chipanera**, Senior Financial Analyst, discusses escalations, cash working capital, regulatory fees, income taxes, leasehold improvements, and related topics.

In **Exhibit 900, Dr. Curtis Dlouhy**, Senior Economic and Policy Analyst, reviews NW Natural's proposals regarding the Climate Protection Program (CPP), Renewable Natural Gas Automatic (RNG) Adjustment Clause (AAC), Residential Line Extension Allowance (LEA), and Meter Modernization Program (MMP).

In **Exhibit 1000, Julie Dyck**, Senior Economist and Utility Analyst, reviews NW Natural's information technology and security (IT&S) projects, cloud-based software, and A&G (NL) expense.

In **Exhibit 1100, Anna Kim**, Energy Costs Section Manager, reviews the Company's Long-Term Hedging, and Schedule H.

In **Exhibit 1200, Charles Lockwood**, Utility Analyst, analyzes uncollectible accounts, and the Company's bill discount program.

In **Exhibit 1300, Mitch Moore**, Senior Utility Analyst, analyzes distribution O&M expense, materials and supplies, customer accounts, affiliated interests, and the Company's atmospheric testing.

In **Exhibit 1400, Ming Peng**, Senior Economist, analyzes depreciation expense, amortization expense, depreciation reserve, amortization reserve, and Allowance for Funds Used During Construction (AFUDC).

In **Exhibit 1500, Nicola Peterson**, Senior Telecom Analyst, analyzes current medical and health insurance, and Current Pension Costs.

In **Exhibit 1600, Rose Pileggi**, Senior Utility Analyst, analyzes NW Natural's capital structure.

In **Exhibit 1700, Paul Rossow**, Utility Analyst, reviews NW Natural's expense related to political activities, advertising, memberships, dues, donations, meals, entertainments, and travel.

In **Exhibit 1800, Eric Shierman**, Senior Utility Analyst, analyzes NW Natural's marginal cost, rate spread, and rate design.

In **Exhibit 1900, Dr. Bret Stevens, Ph.D.**, Senior Economist, analyzes the Company's load forecasting, decoupling, and rate base calculations.

In **Exhibit 2000, Steph Yamada**, Senior Utility Analyst examines NW Natural's wages and salaries, incentives, full time equivalents (FTE), and other related issues.

In **Exhibit 2100, Kervin Hennessy**, Senior Utility Analyst examines NW Natural's safety and inspection programs.

3. CONCERN – FREQUENCY AND AGGREGATE AMOUNT OF INCREASES

Q. Are there any issues that appear in the case that you would like to highlight?

A. Yes. Staff is concerned that the aggregate rate impacts of this general rate case, deferrals, and power costs may constitute an unreasonably energy burden for NW Natural's Oregon utility customers outpacing Oregon wages. According to the Wall Street Journal (WSJ), necessities like food have become much more expensive in recent years.[2] Further, the U.S. Federal Reserve (Fed) is tightening monetary policy to control high inflation.[3] This increases the cost of borrowing for utility rate payers as well as the cost of debt for utilities.

Q. Can you give a general idea of the mindset you would prefer NW Natural executives avoid when considering cost controls and capital project best management practices?

A. Yes. In the news articles cited above, some food company executives have said that "shoppers will adjust over time to higher prices, as they have in the past". This mind set presumes that consumers of goods and services who have finite resources will either consume less or otherwise shift their spending to deal with higher prices on necessities.

While energy efficiency is generally praiseworthy, Staff expects utility leadership to control costs to the extent practicable throttle the frequency and

[2] See Exhibit Staff/109 Muldoon/21 for "It's Been 30 Years Since Food Ate Up This Much of Your Income" by Jesse Newman and Heather Haddon of the WSJ – Feb 26, 2024. Also see Exhibit Staff/109 Muldoon/22 for "How Far $100 Goes at the Grocery Store After Five Years of Food Inflation" by Stephanie Stamm and Jesse Newman of the WSJ – April 4, 2024.

[3] See Exhibit Staff/109 Muldoon/26 for Fed activity on interest rates.

amount of rate increase, and to avoid the presumption that if energy prices rise faster than wages, they utility customers will just need to "adjust" to that new reality.

Q. Please show the approximate impact on residential customer rates were the Company's rate increase implemented as requested.

A. Staff cautions that it is still early in this proceeding and the following depiction reflects a point estimate prior to Staff's filing its Opening Testimony:

Table 2

Current Residential	Avg. Useage/Mo.	Residential Avg. Basic Charge $/Mo.	Residential Avg. Bill $/Mo.
Single Family	55	$ 8.00	$ 79.43
Multi-Family	55	$ 8.00	$ 79.43

	Nov. 1, 2024 Increase	Scenario if increase were $154.9 M*			
NWN Proposed [1]		New Residential Basic Charge $/Mo.	New Residential Avg. Bill $/Mo.	Increase $/Mo	% Increase
Single Family	$154.9 Million*	$ 10.00	$ 93.81	$ 14.38	18.10%
NP Single Family		$ 26.25	$ 66.54	n/a	n/a
Multi-Family		$ 8.00	$ 91.82	$ 12.39	15.60%
NP Multi-Family		$ 24.25	$ 63.92	n/a	n/a

* Oregon jurisdictional revenues overall increase of 16.62 percent

[1] Margin revenues for existing and new premise (NP) were designed to generate an equal amount. Monthly bill is driven by usage differences.

This information does not yet reflect recommendations offered by Staff and intervenors for Commission consideration, which if adopted, would reduce the impact of NW Natural's proposed rate increase.

Q. What does the Company identify as key cost drivers when describing this rate case to investors and analysts?

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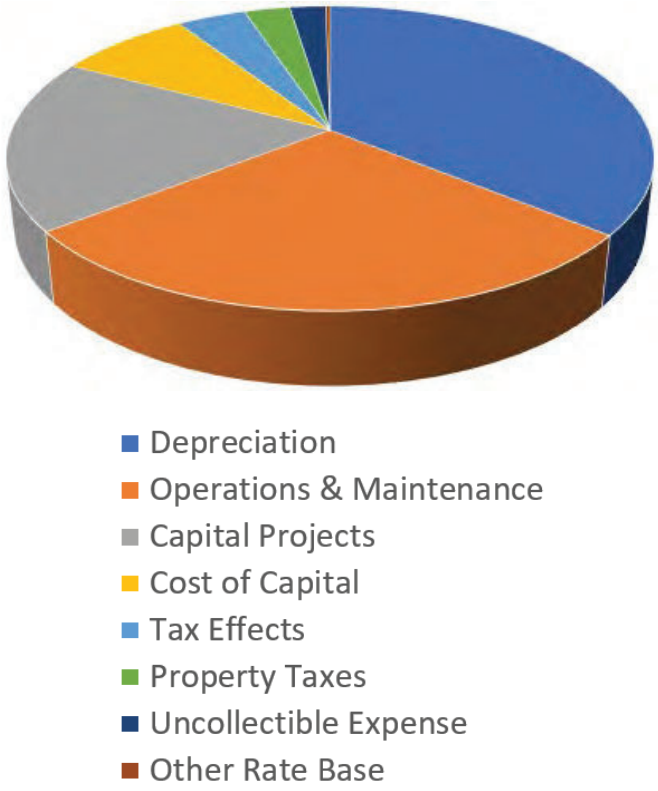
A. With the caution that this is at a very general level, and importantly without showing NW Natural's offsetting revenues and cost controls, the largest drivers of costs in this general rate increase are shown below.

Table 3



Cost Drivers	%
Depreciation	35.92%
Operations & Maintenance	28.57%
Capital Projects	18.36%
Cost of Capital	7.90%
Tax Effects	4.12%
Property Taxes	2.72%
Uncollectible Expense	2.14%
Other Rate Base	0.26%
	100.00%

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Rate Case Cost Drivers	Approximate NWN Proposed Oregon Revenue Requirement	
	$ Millions	Percent
Driver 1: Capital Projects [1] (Examples Below) Current Rate Base $1,755,679 Million (UG 435); Proposed Rate Base $2,136,361 million	**32,948**	21.27%
Central Resource Center	788	0.51%
Meter Modernization	4,559	2.94%
Incremental Cloud Capital (replace end of life software)	3,100	2.00%
Storage Investments for Winter Peak	4,765	3.08%
Other	19,736	12.74%
Driver 2: Cost of Capital (as requested) 10.1% ROE, 50% Equity, 4.712% Cost LT Debt	**14,167**	9.15%
Driver 3: Depreciation	**64,453**	41.61%
Depreciation Study	35,403	22.85%
Increased Capital	29,050	18.75%
Driver 4: O&M	**51,273**	33.10%
2 Years of Wages and Salaries	19,389	12.52%
Customer Payment Processing	1,333	0.86%
Locating Services	2,997	1.93%
IT&S (software licenses)	4,650	3.00%
Other (inflationary pressures across all costs)	22,904	14.79%
Driver 5: Gross Up	**7,401**	4.78%
Federal Income Taxes	1,151	0.74%
State Income Taxes	1,073	0.69%
Franchise Taxes	4,572	2.95%
Corporate Activity Tax	605	0.39%
Driver 6: Uncollectible Expense	**3,848**	2.48%
Driver 7: Property Taxes	**4,888**	3.16%
Driver 8: Other Rate Base	**463**	0.30%
Driver 9: Revenue (net of Cost of Gas)	**-24,531**	-15.84%
Customer Growth	-24,531	-15.84%
Total	**154,910**	100.00%

Staff's testimony will provide more detail on the above costs. Note that the information above does not capture all the Company's tax offsets and offsetting operating revenues as well as cost controls that reduce the impact to customers rates.

Q. What could the Commission do to address general rate increases of the magnitude proposed by NW Natural in this general rate case?

A. One solution proposed by Bob Jenks of the Oregon Citizens' Utility Board (CUB) on that organization's website is for the Commission to set the utility's profit margin at the lowest reasonable point.[4]

Q. Does Staff agree with CUB that this is the Commission's best option?

A. Staff analyzing Cost of Capital (CoC) in this general rate case would not use terms like "allowable profit margins" interchangeably with allowed Return on Equity (ROE). Staff also think holistically about Cost of Capital considering credit ratings and the financial health of Commission jurisdictional energy utilities and their relative strength in financial markets in comparison to their peer or similarly situated like utilities.

However, in advance of reading any testimony by CUB in this general rate case, Staff agrees that the Commission could consider any ROE in Staff's range of reasonable ROE's for Commission Authorized ROE in its final order in this general rate case.

Q. Are there other ways that the Commission could look at using ROE to mitigate the magnitude and frequency of general rate cases?

A. Yes. The Commission could consider using ROE as a throttle to control the frequency of general rate cases. For example, were a utility to file three

[4] Posted January 25, 2024, on https://oregoncub.org/ this proposal within "Is Oregon Utility Regulation Part of the Problem?" by Bob Jenks is reproduced with some small editing changes to fit a written rather than on-screen format at Exhibit Staff/109 Muldoon/13 to capture the context in which the suggestion was made. Also see Exhibit Staff/109 Muldoon/14-16.

general rate cases in a five-year period, the Commission might consider that activity sufficient to reduce regulatory lag and reduce financial risk in terms of metrics like ratio of cash flow from operations before changes in working capital (CFO pre-WC) to debt, in a form meaningful to credit rating agencies.

Q. Would that last approach be immediately applicable in this general rate case?

A. That is uncertain. Persons concerned about the frequency and aggregate magnitude of energy utility rate increases in Oregon are sharing ideas on possible solutions. Consideration of recommendations raised in this general rate case could give the Commission tools to mitigate the impact of frequent rate cases on jurisdictional utility customers. Staff will continue to monitor suggestions on intervenors in this case and closely review the analysis and justifications provided to support such recommendations to the Commission.

The Commission's evaluation of such proposals is consistent with public comments and posting by intervenors asking that the Commission consider impacts on utility customers in its determination of most appropriate just and reasonable outcomes in this case.

Q. Are utility customers helped by falling natural gas prices?

A. Yes. Please see Exhibit Staff/400 Nottingham's discussion of how natural gas prices falling in the first quarter of this year could help control Purchase Gas Adjustment (PGA) and rate case aggregate rate changes on November 1.[5]

[5] NYMEX Natural Gas Prices fell 29.87 percent in the first quarter of 2024. See Exhibit Staff/109, Muldoon/44, "Track the Markets: Quarterly Winners and Losers" published in the Wall Street Journal on April 1, 2024.

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4. OVERALL RATE OF RETURN (ROR)

Q. What did NW Natural include in its initial filing for its overall Rate of Return?

A. The Company. proposes a rate of return of 7.807 percent, with a capital structure comprised of 51 percent equity and 49 percent debt, a 5.104 percent cost of debt, and a 10.40 percent return on equity.

Q. Did you prepare tables showing NW Natural's current Commission-authorized, Company-filed, and Staff-calculated RORs?

A. Yes. The following three tables provide that information.

TABLE 4

NWN Current OPUC Authorized (UG 435 Order No. 22-388, 22-437)			NWN
Component	**Percent of Total**	**Stipulated or Implied Cost**	**Weighted Average**
Long-Term Debt	50.0%	4.271%	2.136%
Preferred Stock	0.0%	0.0%	0.000%
Common Stock	50.0%	9.40%	4.700%
	100.00%	**ROR**	**6.836%**

TABLE 5[6]

NWN Requested – UG 490		NWN Direct Testimony		
Component	**Percent of Total**	**Cost**	**Weighted Average**	**ROR vs. Current**
Long-Term Debt	50%	**4.712%**	2.356%	**0.571%**
Preferred Stock	0%	0.0%	0.000%	
Common Stock	50%	**10.10%**	5.050%	
	100.00%	**ROR**	**7.406%**	

[6] NW Natural/300, Wilson/3.

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TABLE 6

Staff Proposed – UG 490		Staff Opening Testimony		
Component	**Percent of Total**	**Cost**	**Weighted Average**	**ROR vs. Current**
Long-Term Debt	**50.00%**	**4.712%**	2.356%	**0.070%**
Preferred Stock	0%	0.0%	0.000%	
Common Stock	**50.00%**	**9.10%**	4.550%	
	100.00%	**ROR**	**6.906%**	

CAPITAL STRUCTURE

Q. Has the Commission recently considered a preferred target capital structure?

A. Yes. In PacifiCorp's 2020 GRC, the Commission adopted a notional 50 percent equity capital structure. The Commission noted that "[w]e consider all components to the company's cost of capital that will result in a fair and reasonable rate of return, 'to strike a balance between the interests of ratepayers and the interests of investors [,]" and that 50/50 capital structure was an optimal structure for ratemaking.[7]

Q. Does NW Natural continue to target a 50 percent Common Equity / 50 percent LT Debt capital structure?

A. Yes.[8] See Staff/1600 Pileggi for further discussion on capital structure.

COST OF LONG-TERM DEBT

Q. Did parties address Cost of Long-Term Debt in a partial settlement?

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7 *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, UE 374, Order No. 20-473, p. 24 (December 18, 2020).

8 See NW Natural/300, Wilson/3.

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A. Yes. As earlier mentioned in this testimony NW Natural, Staff, the Alliance of Western Energy Consumers, and CUB recommend the Commission adopt a 4.712 percent Cost of Long-Term Debt.

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5. RETURN ON EQUITY (ROE)

Q. What range of reasonable ROEs does Staff recommend, and within that range, what point ROE?

A. Staff observes a range of reasonable ROEs of 8.9 percent to 9.3 percent, with a mean ROE of 9.1, derived from Staff's two separate Three-Stage Discounted-Cash-Flow (DCF) models. Staff does not have a recommended point ROE estimate in this case, which is a departure from its typical practice.

Q. Did you perform a check on the results of Staff's Three-Stage DCF models?

A. Yes. Staff employed two simpler models to check the reasonableness of its findings:

1. A Single-Stage DCF or Gordon Growth Model; and,
2. A Capital Asset Pricing Model (CAPM).

Q. What results did these models generate?

A. The Gordon Growth Model generated a mean ROE of 7.5 percent using Staff's peer electric utilities and 7.7 percent with the Company's peer electric utilities. This model points to the lower end of Staff's three-stage discounted cash flow results.

The CAPM using Staff's usual inputs and methodology generated a mean ROE of 9.2 percent using Staff's peer electric utilities and 9.3 percent with the Company's peer electric utilities. This model supports an ROE at the middle to high end of Staff's three-stage discounted cash flow results.

Based on these checks, Staff utilizes the midpoint estimate of 9.1 percent

for ROE in Table 6 above. However, any point within Staff's range of reasonable ROEs from 8.9 percent to 9.3 percent (rounded up) would be support of a just and reasonable ROE.

Q. Does your recommended ROE meet appropriate standards?

A. Yes. The range or reasonable ROEs Staff recommends is appropriate for overall rates that are reflective of forward looking conditions in conjunction with Staff's adjustments and meets the *Hope* and *Bluefield* standards, as well as the requirements of Oregon Revised Statute (ORS) 756.040.[9] Staff recommendations are consistent with establishing "fair and reasonable rates" that are both, "commensurate with the return on investments in other enterprises having corresponding risks" and "sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital."[10] However, a higher point within Staff's range would be more supportive of current NW Natural credit ratings and financial market expectations.

PEER SCREEN

Q. How did you select comparable companies (peers) to estimate NW Natural's ROE?

A. Staff used companies that met the following criteria as peer utilities to the regulated electric utility activities of NW Natural:

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[9] *See Federal Power Commission v. Hope Natural Electric Co*., 320 U.S. 591 (1944) and *Bluefield* Water *Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923).

[10] *See* ORS 756.040(1)(a) and (b).

1. Covered by Value Line (VL) as an electric utility;
2. Forecasted by VL to have positive dividend growth;
3. LT Issuer Credit Rating greater than or equal to Baa3 from Moody's and greater than or equal to BBB- from S&P;[11]
4. No decline in annual dividend in last five years based on VL;
5. Has heavily regulated electric utility revenue;
6. Has LT Debt from 40 percent to 60 percent inclusive in VL Capital Structure; and[12]
7. Has no recent merger and acquisition activity representing a large portion of the utilities capitalization.[13]

Q. What peer groups of electric utilities did Staff and Company ROE modeling primarily depend on, and were there similarities?

A. The Company and Staff recommended regulated natural gas utility peer groups both drew from pertinent electric utilities covered by VL and with one exception, chose the same peer group. Staff did not select New Jersey Resources Corporation based on how much of its operational cash flows are regulated and that the credit rating coverage for the Company was withdrawn by Moody's and Standard & Poor's. Otherwise Table 7 shows the overlap between NW Natural's and Staff's peer groups.

Q. Did the Company apply some different criteria?

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[11] See Exhibit Staff/101 Muldoon/1 for a table showing how Moody's and S&P ratings compare with each other.

[12] Staff also performs sensitivity analysis looking at a peer screen of 40 percent to 60 percent long-term debt in capital structure. Sensitivity analysis does not impact Staff's modeling results but does answer questions looking at alternative inputs and scenarios.

[13] See Staff/109, Muldoon/36-39 for examples of financial news on mergers monitored by Staff.

A. Yes. However, there was much overlap between NW Natural's and Staff's screening criteria. For example neither Staff nor NW Natural chose UGI Corporation as it primarily sells propane rather than natural gas.

TABLE 7[14]

UG 490 Company	UG 490 Staff
Yes	Yes
No	No
Yes	No
Yes	Yes
Yes	Yes
Yes	Yes
No	No
Yes	Yes
Yes	Yes
No	No

A comparison of the peer groups used by Staff and NW Natural are set forth in Table 9 above. Staff excluded some of the companies used by NW Natural based on the Staff screening criteria described above. Six companies were relied upon by both Staff and NW Natural.

Q. Is the set of Natural Gas utilities followed by Value Line relatively small.

A. Yes. Staff is also doing sensitivity modeling so that the Commission can consider over time whether publicly traded water utilities should be considered in the future as a second combined water and natural gas utilities peer group for a second set of recommendations regarding ROE. In this publication Staff

[14] See Exhibit Staff 102, Muldoon/2 for the full peer screening table.

just upgraded its natural gas utility information to bring its recommendations current with financial markets. Unfortunately Value Line has not yet made its forward-looking updates for water utilities so readers will have to wait for Staff's Rebuttal Testimony to see that modeling. However, because water utility information and modeling are provided only as a sensitivity and will not impact or change Staff's recommendations.

Q. Does NW Natural also offer a larger second peer group for the Commission's consideration?

A. Yes. NW Natural offers select electric utilities as a potential way to expand its natural gas peer group.[15] While Staff does not think this approach is informative for the Commission, the Company is considering ideas on how to address the relatively small group of publicly traded natural gas companies that are like NW Natural.

Bringing such ideas to the Commission may be helpful over the long run. The Commission may not have a best approach in mind now, but then again might not know exactly what it would like to see until it sees it.

MODEL RESULTS

Q. What are the results of your multistage DCF models?

A. See Table 8 below for the results from Staff's Three-Stage DCF modeling.

[15] See NW Natural/400 Coyne-Nelson/22 Figure 6.

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TABLE 8 – RESULTS OF STAFF'S 3-STAGE DCF MODELING[16]

8.9%	to	9.3%
Midpoint	9.1%	ROE

Supporting Exhibit Staff/403, Muldoon/1 shows step-by-step how Staff's Hamada adjusted[17] Three-Stage DCF modeling, using Staff peers and growth rates, generates a higher recommended ROE than using NW Natural's peer electric utility group. Note that Staff rounds upward to generate a top of range value of 9.3 percent.

Q. Does Staff agree with the NW Natural's assertion that the Company's requested ROE of 10.1 percent is reasonable?

A. No. NW Natural comes up with a range of 10.0 percent to 10.6 percent with a recommended point estimate of 10.10 percent.[18] This is a very interesting range as most of the Company's similarly situated and sized (in terms of capitalization) utilities have ROE's authorized within the last two years that are below even the lowest point of this range. According to Regulatory Research Associates (RRA), an affiliate of S&P, the average ROE authorized for electric utilities rose to 9.54 percent for rate cases decided in 2022 from the 9.38 percent average for cases decided in 2021.[19]

16 See Exhibit Staff/103, Muldoon/1 for the results of Staff three-stage DCF modeling.
17 As Staff explains in more detail below, Staff applies the Hamada equation to better compare companies with different capital structures.
18 See NW Natural/403, Coyne-Nelson/1.
19 See Exhibit Staff/109, Muldoon/1 for Average Authorized ROEs in 2023 by Lisa Fontanella, RRA.

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Staff invites the Company to explain further in its Reply Testimony why its results exceed recent state commission authorized ROE's for its modeling peers.

Q. Based on the information you have reviewed can you explain why NW Natural's results appear unreasonably high?

A. Yes. NW Natural inputs unreasonably high assumptions regarding future markets into its financial models. These unreasonably high assumptions, coupled with the relatively simple nature of the models relied on most heavily by NW Natural, leads inexorably to high estimates of what return is necessary to attract investors in today's market.

Q. Please provide an example of an extreme input used in the Company's modeling.

A. Example 1 below shows how important inputs are to ROE modeling. Looking at the difference between NW Natural and Staff inputs, one can see how use of an inflated market return can skew results upward.

Example 1 – NOT a Staff Recommendation:

NWN	4.42%	Rf Rate as shown in Exhibit NWN/400 Coyne-Nelson/13 @31
Opening Testimony	13.31%	NWN Mkt Return
	8.89%	NWN Mkt Risk Premium (MRP) as shown in Exhibit NWN/400 Coyne-Nelson/13 @30
Staff	4.555%	R_f as April 5, 2024 30 Yr UST Yields WSJ Bonds & Rates (wsj.com)
★	9.90%	S&P 500 Market Return 1993 thru 2023
	5.35%	Staff Mkt Risk Premium MRP)

Q. Please show a Capital Asset Pricing Model with Staff's and other more inflated inputs that may be preferred by the Company.

A. In Table 9 below, one can see how applying inputs from the table above to all the peer utilities changes ROE results of CAPM modeling.

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Table 9 – Capital Asset Pricing Model (CAPM) Examples

	Screen #	Abbreviated Utility	UG 490 NWN	UG 490 Staff	UG 490 Staff Sensitivity	Ticker	VL Q1 2024 Beta	ROE w VL Beta CAPM	Screen #	
1	1	Atmos	Yes	Yes	Yes	ATO	0.85	9.10%	1	1
2	3	New Jersey	Yes	No	No	NJR	0.95	9.63%	3	2
3	4	NiSource	Yes	Yes	Yes	NI	0.90	9.37%	4	3
4	5	NW Natural	Yes	Yes	Yes	NWN	0.85	9.10%	5	4
5	6	ONE Gas	Yes	Yes	Yes	OGS	0.85	9.10%	6	5
6	8	Southwest Ga	Yes	Yes	Yes	SWX	0.90	9.37%	8	6
7	9	Spire	Yes	Yes	Yes	SR	0.85	9.10%	9	7
8	10	American Wa	No	No	Yes	AWK	0.95	9.63%	10	8
9	11	California Wa	No	No	Yes	CWT	0.75	8.56%	11	9
10	12	Middlesex W	No	No	Yes	MSEX	0.75	8.56%	12	10
11	13	SJW	No	No	Yes	SJW	0.85	9.10%	13	11
		No. of Peers:	7	6	10			VL Betas		
						Company Screen	Mean	9.3%	ROE	
					Staff Gas and Water Sensitivity Screen		Mean	9.1%	ROE	
						Staff Screen	Mean	9.2%	ROE	

CAPM points toward middle to upper end of Staff's 3 Stage DCF Modeling results.

Staff usually relies on a U.S. Treasury (UST) thirty-year bond as reported by the Wall Street Journal (WSJ) and 30-year monthly geometric returns for the Standard and Poor's (S&P) 500 index as a proxy for market returns. If one instead uses **an extreme arithmetic market return,** one can inflate the results of a CAPM model with few inputs.[20] One can also boost results by using a starting point for data collection in the Great Depression and then including World War II era boom times unlikely to be repeated in the U.S. economy.

Q. Is calculation of a market risk premium calculated from 1926-2003 a good predictor of future U.S. stock returns?

A. No. Since returns over the last thirty years are lower than those experienced earlier in the Country's history, which includes post-World-War II economic

[20] See Staff/104, Muldoon/1 for this CAPM modeling example.

expansion in the U.S, expectations should mirror the recent 30-year returns. According to Ibbotson, reliance on a date range like NW Natural's would overstate likely future market returns.[21]

Q. Is Staff suggesting that CAPM is not a good model to check results of other modeling Staff performs, as advised by the Commission?

A. No. Rather, Staff shows why the Commission accepts CAPM only as a check on ROE modeling and demonstrates how one can abuse the model. If one eliminates unreasonable modeling inputs, selects only peer electric utilities most like NW Natural using Staff's standard screening methods, and eliminates unreasonable inputs, you arrive at a result equal to Staff's ROE recommendations.[22]

STAFF MODELS

Q. Describe the two three-stage DCF models on which you primarily rely.

A. Staff's first model is a conventional three-stage discounted dividend model, which Staff denotes as a "30-year Three-stage Discounted Dividend Model with Terminal Valuation based on Growing Perpetuity" (referred to as "Model X"). This model captures the thinking of a money manager at a pension fund or insurance company, or other institutional investor, who expects to keep the Company's stock indefinitely and use the dividend cash flow to meet future obligations.

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[21] See "The Equity Risk Premium" by William N. Goetzmann and Roger G. Ibbotson available on Amazon.com.

[22] Exhibits Staff/101-105 show how Staff's recommendations are generated.

Staff's second model is the "30-year Three-stage Discounted Dividend Model with Terminal Valuation Based on P/E Ratio" (referred to as "Model Y"). This model best fits the investor who has a goal they are working toward. In addition to the income stream from dividends, this investor intends to sell the stock as the goal is reached.

Both models require, for each proxy company analyzed by Staff, a "current" market price per share of common stock, estimates of dividends per share to be received over the next five years calculated from information provided by Value Line, and a long-term growth rate applicable to dividends 10- to 30-years out. On this last point, Staff always recommends the Commission be particularly vigilant for any substitution of a short-term growth rate for a long-term 20- to 30-year growth rate. Some growth rates labeled "long" may be supported by information looking at the next ten years or less into the future.

For a smooth transition, Staff steps the rate of dividend growth between the near-term (the next five years) and that of long-run expectations.

Q. How does Model X calculate the terminal value of dividends as a perpetual cash flow into the future?

A. Model X includes a terminal value calculation, in which Staff assumes dividends per share grow indefinitely at the rate of growth in Stage 3 ("growing perpetuity"). In contrast, Model Y terminates in a sale of stock where the price is determined by our escalated price/earnings (P/E) ratio.

Q. Why is thirty years the primary horizon for financial decision-making?

A. Investors focus on the 30-year U.S. Treasury (UST) Bond against alternate investment opportunities. Thirty years is a generally accepted period for economists to ascribe to one generation. It is a common length of time for mortgages of plants, equipment, and homes. Many institutional holders of utility securities match the cash flows from utility dividends to future obligations, such as the payout of life insurance, preparing to meet future pension and post-retirement obligations, and interest service for borrowing. Individuals plan for the education of their children, ownership of their home, and provision for their retirement on this same multi-decade timeframe.

Staff uses five years for Stage One, as that is the timeframe for which Value Line estimates of future dividends are available. This is as far as Value Line projects near-future trends. Staff also uses five years for Stage Two as a reasonable length of time for individual company's dividend growth rates that are materially different from the growth rate used in Stage Three (and common to all companies) to converge to a LT dividend growth rate more representative of all electric utilities.

Q. How do you address dividend timing?[23]

A. Each model uses two sets of calculations that differ in the assumed timing of dividend receipt. One set of calculations is based on the standard assumption that the investor receives dividends at the end of each period.

The second set of calculations assumes the investor receives dividends

[23] See Exhibit Staff/108 for Value Line (VL) information relied on in this testimony regarding publicly traded natural gas and water utilities.

at the beginning of each period. Each model averages the unadjusted ROE values to generate an Internal Rate of Return (IRR) produced with each set of calculations for each peer utility. This approach accounts for the time value of money, closely replicating actual quarterly receipt of dividends by investors.

Q. What price do you use for each peer utility's stock?

A. Staff used the average of closing prices for each utility from the first trading day in February 2024, March 2024, and April 2024, to represent a reasonable snapshot of utility stock prices.

GROWTH RATES USED IN THIRD STAGE OF DCF MODELS[24,25]

Q. What long-term growth rates did you use in Staff's two three-stage DCF models?[26,27]

A. Staff used three different long-term growth rates, with different methods employed in developing each.

The first method uses the U.S. Congressional Budget Office's (CBO) 4.46 percent nominal 20-year GDP growth rate estimate.

Staff's second Composite Growth Rate applies a 20 percent weight to each of the following referent entities long-term growth rates: EIA, Organization for Economic Co-operation and Development (OECD), the U.S. Social Security

[24] See Exhibit Staff/106, Muldoon1 for BEA historical GDP growth rates.

[25] See Exhibit Staff/107 Muldoon1 for TIPS implied long-run inflation rates.

[26] Methods used here related to GDP-based growth rates are similar, if not identical to methods Staff has used in past proceedings. *See*, as an example, Staff's discussion of these methods and, to a limited extent, their conceptual underpinnings in Docket No. UE 233, Exhibit Staff/800, Storm/46 – 52. Growth rates relied upon by Staff are also shown in Exhibit Staff/104, Muldoon/1.

[27] See three-stage DCF models X and Y in Exhibit Staff/103.

Administration (SSA), the Congressional Budget Office's (CBO), with the remaining 20 percent as the average annual historical real GDP growth rate, established using regression analysis of U.S. Bureau of Economic Analysis (BEA) Nominal Historical,1980 Q1 – 2022 Q4, for the period 1980 through 2021, to which we apply a TIPS implied inflation forecast. These growth rates are shown below in Table 10.

Staff's third Composite Growth Rate is BEA Nominal Historical,1980 Q1–2023 Q4. These growth rates are shown below in Table 10.

TABLE 10
GROWTH RATES STAFF RELIED UPON

Stage 3 – Long-Term Annual Dividend and EPS Growth Rates						
Component	Real Rate	TIPS Inflation Forecast	20-Yr Nominal Rate	Weight	Weighted Rate	
Energy Information Administration (EIA)	2.24%	2.39%	4.69%	20.0%	0.94%	
Organization for Economic Co-operation and Development (OECD)ggridlines	1.81%	2.39%	4.24%	20.0%	0.85%	
Social Security Administration (SSA)	1.95%	2.39%	4.39%	20.0%	0.88%	
Congressional Budget Office (CBO)	2.02%	2.39%	4.46%	20.0%	0.89%	
BEA Nominal Historical,1980 Q1–2023 Q4	2.65%	2.39%	5.10%	20.0%	1.02%	
Composite				100%	4.58%	Composite
Congressional Budget Office Long-Term 20-Year Budget Outlook			3.80%	100.0%	4.46%	CBO
BEA Nominal Historical,1980 Q1–2023 Q4	2.65%	2.39%	5.10%	100.0%	5.10%	Historical

Q. Did your analysis reflect a synthetic forward curve?

A. Yes. Staff utilized synthetic forward curve using UST Treasury Inflation Protected Securities (TIPS) break-even points. This reflects implied market-based inflationary expectations. Staff's recommendations are consistent with market activity indicating investor expectations of future inflation.

Staff assumes for purposes of its three-stage DCF modeling that LDC utility growth is bounded by the growth of the U.S. economy, and more

specifically impacted by challenges regarding U.S. population, workforce participation, and productivity in the long-run (20-year) modeling period.

Q. How do your methods employed in this case differ from those utilized by Staff in recent general rate cases?

A. Staff's methods and modeling parallel those employed by Staff in recent electric utility general rate cases. Staff continues to look primarily to referent federal sources for long-term GDP growth rates which weight long-run population, workforce participation, and productivity higher than current financial market events and global events with shorter if not transitory effects. Nevertheless, Staff monitors current financial news, and this testimony is informed by such.[28]

Q. Do you capture both the perspective of a buy and hold investor and an investor who plans to sell in the future?

A. Yes. Staff's recommended 8.9 to 9.3 percent range of reasonable ROEs is consistent with findings modeling the perspectives of both types of investors through Staff's two different three-stage DCF models.

Q. Does this approach capture a reasonable set of investor expectations like Staff's analysis in other recent general rate cases?

A. Yes.

Q. Is it appropriate to use estimates of long-term GDP growth rates to estimate future dividends for electric utilities?

[28] See Exhibit Staff/109, Muldoon/1-47 for news that investors in electric utilities are seeing.

A. Yes. In many of the Company's prior rate cases, Staff has shared plots of U.S. electric demand growth since 1950 on a three-year moving average. This downward trending consumption curve allows GDP growth to be a conservative proxy for both electric utility sales and dividend growth rates.

Q. Can relying on a long-term GDP growth rate overstate required ROE?

A. Yes. It is possible that Staff modeling anticipates greater growth than may be realized and so overstates required ROE to attract investors. Our highest growth rate presumes return to near historical U.S. GDP growth rates.

Q. Is it important to distinguish between long-run 20- to 30-year rates and rates over the next five years?

A. Yes. Over-extrapolating a snapshot of short-term data undermines confidence in modeling results. For example, Value Line, Blue Chip, and a variety of other financial resources focus primarily on the next five years. The next five years may be affected by recent events. Over the long run, population and productivity are the key drivers of economic growth. This is of concern with declines in the rate of growth of America's population.[29]

Q. In Staff's two different three-stage DCF models, Staff is looking for growth rates for a period between 10 and 30 years in the future, or an average of 20-years out. Why not just use a five- or ten-year projection?

A. Staff could use a five- or ten-year projection, but there is better information available. If a primary concern is whether enough Americans are both working

[29] See Exhibit Staff/109, Muldoon for concerns about Oregon population growth.

and highly productive to support a robustly growing economy 30 years from now, 10-year data will not be the most useful. This is because 10-year data is not yet impacted by retirement of persons born in 1960 or persons not immigrating and not being born to U.S. families now. A better solution is to use data that is projected with those difficulties in mind, i.e., 30-year data.

HAMADA EQUATION

Q. Your application of the Hamada Equation to un-lever peer utility capital structures and to re-lever at NW NATURAL's target capital structure increases required ROE. Why is this adjustment reasonable?

A. Staff employs the Hamada Equation to better compare companies with different capital structures driven by differing amounts of outstanding debt. As earlier discussed, Staff applied screening criteria already identify peers that have a very close capital structure to the Company. Use of the Hamada-adjusted results helps ensure that Staff has captured all material risk in our analysis because it captures additional risk associated with varying capital structure.

Within the confines of Staff's testimony, one can see the steps to un-lever and re-lever a peer company's capital structure as the equivalent of removing debt of peer companies with varying capital structures, and then adding enough debt back to equal the Company's balanced target capital structure in this general rate case.

Q. What accounts for differences in peer capital structures?

A. Each of the two models employs the Hamada equation[30] to calculate an adjustment for differences in capital structure between each peer utility and the Staff-proposed capital structure for the Company. When few peer utilities are available, the Hamada equation ensures Staff's analysis addresses differences in peer utility capital structures.

Q. Why is it important to consider capital structure when modeling ROE?

A. Different amounts of debt financing along with different tax rates result in disparate risk profiles among peer utilities used in ROE modeling to approximate the unknown appropriate ROE for the utility examined. All else equal, with more debt in a capital structure, investors require higher expected equity returns to compensate for the increased risk. Debt has a higher call on the company's available cash, and so less cash is available for equity holders. Staff uses the Hamada equation, named after Robert Hamada, to separate the financial risk of a levered firm from its business risk, and adjust the results of peer utilities to have results as though they had the same capital structure as the utility for whom an appropriate ROE is sought.

Q. Did Staff use a capital structure peer group screen with 40 percent to 60 percent debt, carrying more interest rate risk than NW Natural?

[30] Dr. Robert Hamada's Equation as used in Staff/404 separates the financial risk of a levered firm, represented by its mix of common stock, preferred stock, and debt, from its fundamental business risk. Staff corrects its ROE modeling for divergent amounts of debt, also referred to as leverage, between the Company and its peers.

A. Yes. Inclusive of Hamada adjustments, the higher debt sensitivity peer group would decrease Staff's recommended ROE by 24 basis points. In general, the Hamada equation addresses the capital structure itself to a certain degree, companies taking on more debt may also be taking on more risk in other areas than finance.

Q. Did Staff use robust and proven analytical methodologies?

A. Yes. Staff's methods are robust, proven, and parallel Staff's work for many years. The Commission, for example, expressly relies on the multi-stage DCF to determine the range of ROEs and relies on CAPM and risk premium models to check the reasonableness of results. This can be seen in Order No. 22-129 in Portland General Electric Company's GRC (Docket No. UE 394) as well as in Order No. 20-473 in PacifiCorp's GRC (Docket No. UE 374).

Q. Describe how you performed your analysis.

A. Using the cohort of proxy companies that met our screens, Staff ran each of Staff's two three-stage DCF models three times, each time using a different long-term growth rate.

Q. Was your analysis consistent with a range of reasonable ROE's from 8.9 percent to 9.3 percent?

A. Yes.

<u>Balanced Approach to ROE</u>

Q. Is picking a best fit ROE within Staff's suggested range of reasonable ROE's an easy decision for the Commission.

A. No. On the one hand, a lower ROE would reduce the impact of this general rate increase on NW Natural's utility customers in Oregon. This thought is likely foremost for CUB members and employees based on the earlier cited statement by Director Bob Jenks.

On the other hand, a higher ROE is more supportive of the Company's credit ratings, which are under pressure based on financial metrics and from those who would like to migrate from natural gas for space heating and other purposes to greater reliance on renewably generated electricity or other alternatives to natural gas. Also the Oregon overall regulatory environment is a very large part of rating agency decision making. And these ratings influence the Company's borrowing cost in a period of significant spending for plant additions. A utility customer might think of this like buying the same house at low or high interest / mortgage rates.

Balancing these and other considerations is necessary for the Commission to make decisions consistent with the Hope and Bluefield legal decisions mentioned earlier.

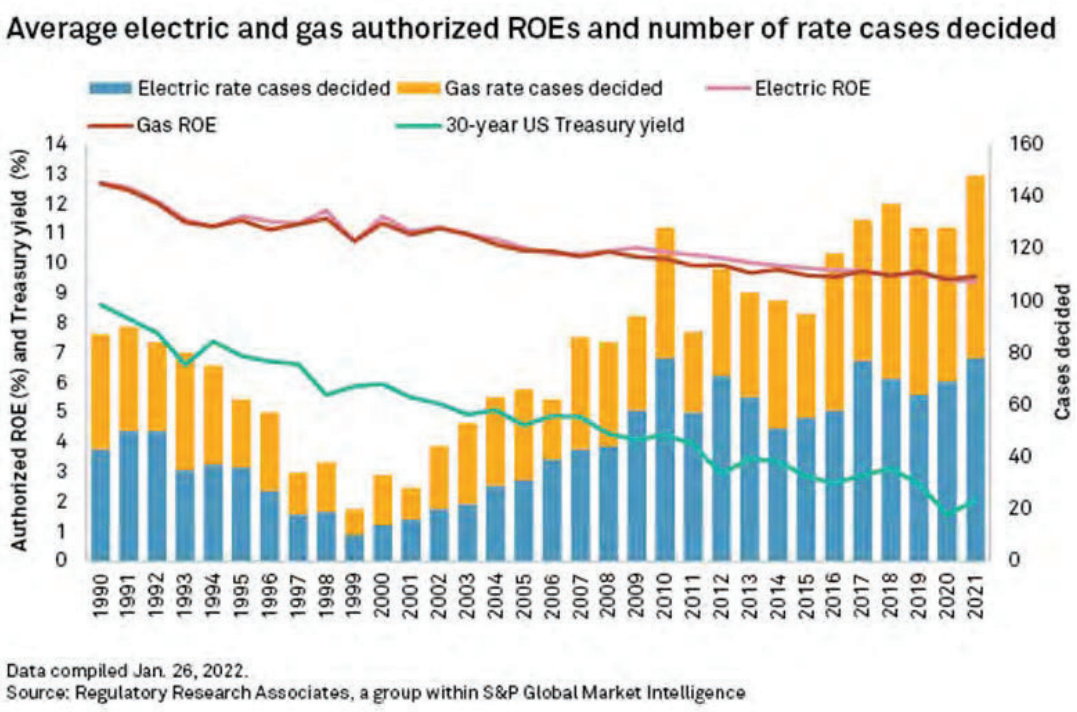
Q. Are we in a rising interest rate environment that compels higher ROEs?

A. No. The U.S. Federal Reserve expects to lower interest rates in the next two years.[31] Further interest rates and ROEs are both declining when looked at over a 30-year time frame. The downward glide path for ROE in Figure 1 below is not linear and may fluctuate through these uncertainties, but long-run

[31] See Staff/109, Muldoon/26.

GDP growth rates are mostly determined by the long future U.S. working age population and its productivity. These are downward pressures on GDP growth.

FIGURE 1 – Downward Glide Path of Utility ROES[32]



Q. What trend is Staff seeing?

A. Since 1990, according to Regulatory Research Associates (RRA), Electric and Electric Utility authorized ROEs have declined as the 30-year US Treasury (UST) has also declined. While the Fed recently raised interest rates, the Fed now anticipates loosening money supply soon.

[32] Published by Regulatory Research Associates (RRA), an affiliate of S&P Global Market Intelligence on Feb. 10, 2022.

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GORDON GROWTH MODEL – As Check on ROE Findings

Q. What is the Gordon Growth model?

A. The Gordon Growth model (or Single Stage DCF model), similarly to the Three-Stage DCF model, is based on the principle that a company's value is equal to the net present value (NPV) of all its future cash flows and the company's current stock price. The Single-Stage DCF uses simpler assumptions than other models however, with dividend payments representing the only cash flow, and an assumption that growth will remain constant in perpetuity.[33]

Q. What are the positive aspects and potential shortfalls of the DCF model?

A. The most positive aspect of the Single-Stage model is its simplicity. An analyst can use this model to calculate a rudimentary cost of equity valuations without needing complex inputs or analysis, beyond selecting a trusted source for the next quarter's expected dividends. In fact, after some algebraic simplification, the return can be expressed by:

$$R = \frac{D_1}{P_0} + g$$

Where $\boldsymbol{R}$ is estimated ROE, $\boldsymbol{D_1}$ is the first dividend paid after stock purchase, $\boldsymbol{P_0}$ is the stock price, and $\boldsymbol{g}$ is the growth rate.

Caution and discretion must be used when sourcing inputs to the model; for example, growth rates should be based on well vetted and

[33] See Docket No. UG 347, Staff/1300, Muldoon Watson/31 – 39, for further discussion of the Single-Stage DCF model, and the Commission's historical treatment of its results.

reliable sources, as opposed to sell-side marketing information used by investment advisors to entice new investors. This is important to bear in mind when considering the results of any Single-Stage model, as reliance on overly optimistic inputs or use of outboard after-the-fact adjustments can have a large impact on the model output.

The Single-Stage model is based on simple principles and serves as a rough estimation of investor required ROE. It cannot incorporate known, measurable, and material information about the future usually built into Three-Stage DCF analysis. For this reason, Staff, consistent with Commission precedent, has traditionally only relied on it as a sensitivity check when rate making.

Q. How does Staff determine the dividend flow and growth rate for the single-stage DCF?

A. Much like Staff's Multi-Stage DCF, Staff sources its expected dividends from Value Line. We calculate the average dividend growth rate by comparing the expected dividend by Value Line and actual dividend for each for each company in the peer screen.

Q. What inputs does Staff use to build Staff's single-stage DCF model?

A. Staff uses the same representative draw of stock prices to build its single-stage DCF model as it uses in the three-stage DCF model. Current dividends and anticipated dividend growth are sourced from Value Line.

Q. What are the results of Staff's Gordon Growth model?

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A. Using Staff's peer utility screen, the average required ROE under Staff's Gordon Growth model is 7.5 percent.

TABLE 11[34]

	1	2	3	4	5	6	7	8	9	11 = 9 + 10	13	14	15
	Screen #	Abbreviated Utility	UG 490 NWN	UG 490 Staff	UG 490 Staff Sensitivity	Ticker	Recent Stock $ Price	Current Dividend Yield	Next VL Annual Dividend	Anticipated Dividend Yield	VL Dividend Growth	Investor Required ROE	Screen #	
1	1	Atmos	Yes	Yes	Yes	ATO	116.00	2.6%	3.22	2.8%	7.3%	10.1%	1	1
2	3	New Jersey	Yes	No	No	NJR	42.43	3.7%	1.68	4.0%	5.0%	8.9%	3	2
3	4	NiSource	Yes	Yes	Yes	NI	26.97	3.7%	1.06	3.9%	4.2%	8.1%	4	3
4	5	NW Natural	Yes	Yes	Yes	NWN	33.46	5.8%	1.95	5.8%	0.4%	6.2%	5	4
5	6	ONE Gas	Yes	Yes	Yes	OGS	62.62	4.2%	2.64	4.2%	2.4%	6.7%	6	5
6	8	Southwest Gas	Yes	Yes	Yes	SWX	72.94	3.4%	2.48	3.4%	1.1%	4.5%	8	6
7	9	Spire	Yes	Yes	Yes	SR	60.01	4.8%	3.02	5.0%	4.7%	9.7%	9	7
8	10	American Water	No	No	Yes	AWK	119.76	2.3%	3.00	2.5%	-100.0%	-97.5%	10	8
9	11	California Water	No	No	Yes	CWT	46.04	2.3%	1.12	2.4%	-100.0%	-97.6%	11	9
10	12	Middlesex Water	No	No	Yes	MSEX	50.55	2.5%	1.32	2.6%	-100.0%	-97.4%	12	10
11	13	SJW	No	No	Yes	SJW	55.37	2.7%	1.60	2.9%	-100.0%	-97.1%	13	11
		No. of Peers:	7	6	10							Mean		
											Company Screen	7.7%	ROE	
											Staff Gas and Water Sensitivity Screen	N/A	ROE	
											Staff Screen	7.5%	ROE	

Findings in Table 11 above support selection in the lower end of Staff's range of reasonable ROEs.

34 See Exhibit Staff/105, Muldoon/1 for Staff's full Gordon Growth Model.

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CAPM – As Check on ROE Findings

Q. What is the Capital Asset Pricing Model (CAPM)?

A. The CAPM assumes that a stock's return on equity is a function of a risk-free return and a risk premium and that the risk premium should be augmented by a company's level of risk relative to the market, which is captured by Beta or β. All told, CAPM takes the form:

$$\boldsymbol{Required\ Return} = \boldsymbol{r_f} + \boldsymbol{\beta}(\boldsymbol{r_m} - \boldsymbol{r_f})$$

Where $\boldsymbol{r_f}$ is the risk-free rate and $\boldsymbol{r_m}$ is the market return. Generally, the risk-free rate is assumed to be the rate of return on bonds. Taking cues from long-standing financial modelling, Staff calculates its CAPM using the yield on 30-year and 10-year US Treasury bonds as stand-ins the risk-free rate.

Q. Should the Commission scrutinize CAPM carefully?

A. Yes. CAPM only relies on a few inputs. In this case, there are three inputs: the risk-free rate, the market return, and the choice of Beta. Although it is generally agreed that the rate of return on US Treasury bonds is the proper choice for the risk-free rate, there is much discussion about what maturity should be used for Beta and the market return.

There are a variety of sources to find or calculate both Beta and the market return. Because there are so many sources for two inputs into this simple model, an uninformed or malicious investigator could use unrepresentative values to motivate abnormal required returns. It is therefore of the utmost importance to be thoughtful and consistent in choosing CAPM parameters. In Commission activities, we have standardized on Value Line

(VL) Betas that are broadly used to give apples-to-apples modeling output comparisons. Staff has used CAPM for validation rather than rate setting in past cases.

Q. Where do you find information on companies' Beta estimates?

A. Estimates of Beta can be found from many sources including Bloomberg, Yahoo Finance, and VL. Traditionally, the Commission has relied on Value Line's Beta estimates to conduct analysis to maintain consistency in regulation between rate cases. The perils of switching between Beta estimates, known as "Beta shopping," will be addressed later in this testimony.

Q. Where do you find information on market returns?

A. Market returns can also be found or calculated from a variety of places. Two common sources for market returns are historical returns on stock market indices and projections for future growth. As earlier discussed, care should be taken in selecting a market return due to the volatile nature of the stock market.

Q. What issues can arise from an improper market return selection?

A. For any company with a positive Beta, a higher market return translates directly into a higher required return according to the CAPM formula. Overstating market returns, a required return estimate can vary by up to three percent for a typical regulated utility.

Q. How does Staff recommend that market returns be calculated?

A. Staff recommends that market returns be calculated based off the historic long-run growth rates of stocks and an up-to-date measure of the risk-free rate. By using historical averages, a modeler does not run the risk of a large shock in

one period unnecessarily augmenting estimated returns, much like the large negative shock caused by the COVID-19 pandemic, the roaring economic recovery post-pandemic, or the ongoing conflict in Ukraine.

As has been done in past rate cases, Staff uses the market risk premium calculated by Ibbotson and the implied market risk premium from Morningstar's Stocks, Bonds, Bills, and Inflation 2015 Classic Yearbook, which measures average returns since 1926. These two sources imply that the risk premium would be 4.5 percent and 6.0 percent, respectively. Staff also calculates market risk premiums as described herein using annualized monthly data for 30 years of geometric S&P 500 returns paired with current 30-year UST yields.

Q. What recommendations do you have for the maximum authorized ROE according to CAPM?

A. As stated previously, Staff only uses CAPM for validation rather than rate setting due to its historic unreliability. Within Staff's peer utility screen, the estimated ROEs from Staff's CAPM under Staff assumptions average 9.2 percent. Using the Company's peer screen and Staff's methods, the average estimated ROE observed is 9.3 percent. If one uses the Company's inflated market risk premium, one can boost results to 12.4 percent like that found as underlying averaged components in NW Natural's testimony.

Q. Has the Commission determined that CAPM should not be relied upon as a stand-alone modeling method?

A. Yes. The Commission made this determination in two general rate cases in 2001 with the issuance of Order No. 01-777 and Order No. 01-787, but still permits use of the CAPM as a check on other modeling methods employed.[35]

DIFFERENCES IN NW NATURAL ROE MODELING FROM STAFFS

Q. What are other differences in the Company's modeling that lead to different ROE modeling results.

A. Staff relies on Value Line data, which generally avoids benchmark shopping.

Q. What is benchmark shopping?

A. Benchmark shopping is performing a review of different data sources with different calculation methods and taking from that cross section certain benchmark data that is then argued before the Commission is most appropriate for this instance of use. The Commission then gets to hear exhaustive arguments on subjects such as the reversion to mean calculations behind Value Line, Bloomberg, and various other potential benchmarks. After an exhaustive examination, the use of alternate benchmarks can be usually determined by the Commission to be obfuscation that detracts from the exercise or modeling at hand.

Q. What are other ways that NW Natural's testimony on ROE might be considered off target?

A. In the Company's discussion of its selection of Risk-Free Rate in CAPM analysis, the Company offers various methods and then averages them.

[35] *In the Matter of Portland General Electric*, Docket No. UE 115, Order No. 01-777 at 32; *In the Matter of PacifiCorp*, Docket No. UE 116, Order No. 01-787 at 21 (September 7, 2001).

What the Company does not mention is that it is averaging a variety of methods of inflating estimation of market results and market risk premium (MRP). For example, averaging super optimistic future projections of market returns with overly-long 90-year market returns does not yield a conservative MRP likely to reflect the near future. Think of this like trying to estimate the weight of your cat or dog. One could take the average weight of a whale, and the average weight of an elephant (both mammals) and suggest that would be an excellent proxy for the weight of your pet. The first estimate for the whale is too large. The second estimate of the elephant is also too large and not reflective of a conservative estimate because though it is smaller than that of the whale, it is still not a good estimate of the weight of your pet.

Q. What other misdirection might the Commission watch for?

A. The Commission should be vigilant for the substitution of five- to ten-year growth rates and other near-term data for 20- to 30-year data and projections from referent entities. Depending on the context, five- to ten-year data can be characterized as “long-term.” But, for purposes of the analysis to estimate ROEs, long-term means 20-30 years in the future.

Generally, Value Line and Blue-Chip type resources focus on the next one to five years and call a future projection five to ten years into the future their long-tern projection. In contrast the U.S.: Social Security Administration, the Congressional Budget Office, the Bureau of Economic Analysis, Energy Information Administration, and other federal referent bodies mean 20-30 years into the future when they say “long-term”.

Q. Why is that important in the context of ROE modeling?

A. Over the next few years, the United States still has a large working age population, despite the graying of America. Productivity has declined in recent years, but near-term GDP growth is still relatively strong.

But looking out 20-30 years, many Americans will be retired, and various other challenges cause referent entities to project lower GDP growth. So averaging a set of near-term growth numbers and using that average in lieu of long-run numbers from referent entities talking about 20-30 years in the future also boosts ROE modeling results.

Q. When will Staff provide more detailed examples of these approaches in NW Natural's ROE modeling?

A. Because Staff has just updated its natural gas utility peer market information to be current as of April, Staff will have time to illustrate how some of the above techniques are used in the Company's ROE modeling to present the appearance of conservative model building while inflating ROE model results.

Q. What was the result of Staff's updating its ROE modeling to incorporate most current market data?

A. Staff's top end of its ROE modeling results dropped 10 basis points from the modeling Staff did based on January 2024 market information.

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6. PENSIONS AND POST RETIRMENT MEDICAL EXPENSE

Q. Does Staff recommend an adjustment to the Company's pensions and post-retirement medical expense in this general rate case?

A. No.

Q. Did Staff carefully analyze the Expected Return on Assets for each of the Company's pensions and post-retirement medical expense?

A. Yes. Staff performed its usual robust analysis, discussed these issues in detail at a workshop with the Company on March 5, 2024, and issued follow-up data requests, the responses to which corroborated Staff's findings. Staff found the Company's actuarial work consistent with the Company's benchmarks inclusive of EROA for Oregon Public Employee Retirement System (PERS), CA PERS, and California State Teachers' Retirement System.

Q. Did Staff carefully analyze the discount rate assumptions for each of the Company's pensions and post-retirement medical expense?

A. Yes. Staff also calibrated the revenue requirement impact of each of the above factors and confirmed that in aggregate the Company's work in this area was reasonable and no adjustment is required in this general rate case.

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7. PHYSICAL AND CYBER SECURITY

Q. Does Staff recommend an adjustment to Information Technology (IT) and Security (IT&S) projects?

A. Please see Exhibit Staff/1000 Dyck for detail on Staff review of IT&S Projects that go into service in the test year.

Q. Does Staff Review the Company's project management performance and cost controls in compliance with TSA Security Directive 2 and updates thereto?

A. Yes. The Commission's RSUP group including Accounting and Finance, Safety, and Energy Costs Staff are reviewing the Company's investments in both physical and cyber security on an ongoing basis.

Q. Will Staff discuss the Companies practices and detailed costs of certain projects herein?

A. No. The Commission's RSUP group including X Accounting and Finance, Safety, and Energy Costs Staff are reviewing the Company's investments in both physical and cyber security on an ongoing basis to comply with U.S. Transportation Security Administration (TSA) and other agencies directives and to protect critical infrastructure in general.

Q. Why is this information on a "Federal Need to Know Basis"?

A. Proper handling of highly confidential critical infrastructure information protects the lives, livelihood, and modern standard of life for Oregonians.

Q. When federal agencies mandate the Company comply with new or updated directive does that give NW Natural a blank check to spend

whatever it takes and take a "cost is no object" approach to physical and cyber security?

A. No. Like all other project management the Commission reviews, NW Natural must consider less costly next best alternatives to its physical and cyber security capital spending and other initiatives. The Company must practice prudent project management and cost controls based on what is known and knowable at the time of NW Natural's decisions.

Q. What sort of risks does the Company have to consider in prudently managing its expenditures?

A. In general, the Company must consider two main types of risk. The first type is protection against something that is relatively likely to happen. One might think of this as a focus on the 95 percent of risks most likely to materialize.

But then a Commission jurisdictional energy utility must also consider and protect against High-Impact Low-Frequency (HILF) events. These are unlikely to happen, but if they do happen, outcomes could be catastrophic.

Q. Why does Staff look at these issues on an ongoing, open-ended basis?

A. Directives, standards, and best practices regarding physical and cyber security that the Company must comply with are regularly changing to address emerging concerns. Rather than a one-and-done review, Staff teams of financial and safety professionals, and engineers must vigilantly review incremental new Company initiatives and expenditures.

Just as utility customers cannot make necessary purchases at any price or only consider the most expensive options in life, utilities must frugally put in

place assets and processes that get the job done effectively at reasonable cost.

Docket No: UG 490

Staff/100
Muldoon/50

8. CONCLUSION

Q. What is Staff's recommendation regarding ROE?

A. Staff recommends that the Commission select a point ROE from within Staff's range of reasonable ROE's from 8.9 percent to 9.3 percent (after rounding). This is a difficult decision balancing financial market criteria and credit ratings on the one hand against reducing energy burden for Oregon customers of NW Natural on the other.

Q. What Rate of Return (ROR) is generated by the Staff's aggregated Cost of Capital recommendations on Capital Structure, ROE, and Cost of Long-Term Debt?

A. Staff provides an illustrative 6.906 percent Overall Rate of Return (ROR), based on the midpoint of Staff's range of reasonable ROEs of 9.10 percent, a 50 percent equity layer Capital Structure, and the settled 4.712 percent Cost of Long-Term Debt.

Q. What recommendation does Staff have regarding a point estimate within Staff's range of reasonable ROEs?

A. Staff finds that recommending a range is appropriate rather than any single point estimate. The range is from 8.9 percent to 9.3 percent. The range provides values from which the Commission can use to balance the interests of shareholders and energy affordability for Oregon utility customers and still meet statutory requirements to provide for a fair return on equity.

Q. Does Staff recommend an adjustment to pensions and post-retirement expense in this general rate case?

A. No. Staff's usual robust analysis found the Company's work on these issues to be reasonable and in aggregate consistent with Staff's benchmarks.

Q. Does Staff recommend incremental adjustments in this testimony over those provided IN Exhibit Staff/1000 Dyck for IT&S projects?

A. No.

Q. Does that conclude your testimony?

A. Yes.

CASE: UG 490
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 101

ROE – Three-Stage DCF: Peer Screen, Dividends, Earnings per Share (EPS), and Hamada Equation

April 18, 2024

Acronyms and Abbreviations Used

CIK	SEC Central Index Key
EDGAR	SEC Electronic Data Gathering, Analysis and Retrieval System
EEI	Edison Electric Institute
EIN	IRS Employer Identification Number
IRS	U.S. Internal Revenue Service
SEC	U.S. Securities and Exchange Commission
SIC	Standard Industrial Code
SNL	SNL Financial, LC – A financial Information gathering firm
U.S.	United States of America
VL	Value Line Investment Survey, The

Moody's		S&P		Fitch		DBRS		
Long-term	Short-term	Long-term	Short-term	Long-term	Short-term	Long-term	Short-term	
Aaa	P-1	AAA	A-1+	AAA	F1+	AAA	R-1H	High Grade
Aa1		AA+		AA+		AA(high)		High grade
Aa2		AA		AA		AA	R-1M	
Aa3		AA-		AA-		AA(low)		
A1		A+	A-1	A+	F1	A(high)	R-1L	Upper medium grade
A2		A		A		A		
A3	P-2	A-	A-2	A-	F2	A(low)		
Baa1		BBB+		BBB+		BBB(high)	R-2H	Lower medium grade
Baa2	P-3	BBB	A-3	BBB	F3	BBB	R-2M	
Baa3		BBB-		BBB-		BBB(low)	R-2L, R-3	
Ba1	Not prime	BB+	B	BB+	B	BB(high)	R-4	Non-investment grade speculative
Ba2		BB		BB		BB		
Ba3		BB-		BB-		BB(low)		
B1		B+		B+		B(high)		Highly speculative
B2		B		B		B	R-5	
B3		B-		B-		B(low)		
Caa1		CCC+	C		C	CCC(high)		Substantial risks
Caa2		CCC				CCC		
Caa3		CCC-				CCC(low)		
						CC(high)		
		CC		CCC		CC		

Source: http://en.wikipedia.org/wiki/Credit_rating

NWN GRC UG 490 | **Peer Utility Screen** | **Staff/101 Muldoon/2**

Natural Gas
NWN UG 490

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
		Screen:	6	VL Gas Utilities passing Staff Peer Screen	80% Mid Cap												Either / Or						
		Sensitivities:	8	VL Gas Utilities passing Co. Screen																			
		Gas Group				VL Cap Small Mid Large	S&P Global Market Intelligence MI Key	SPCIQ Key	IRS EIN	SEC File	VL 3/28/2024 Beta <1	Yahoo Fin. 3/28/2024 Beta	Yahoo Fin. 3/28/2024 Mkt Cap $ Billions	VL 3/28/2024 Mkt Cap $ Billions	Value Line N-Gas Utility w VL Beta < 1 3/28/2024	VL No Div Declines 5 years	S&P Local LT 3/28/2024 Rating ≥ BBB-	Moody's Local LT 2/2/2024 Rating ≥ Baa3	Last 10-K Highly Regulated LDC Revenue	VL 2024 LT Debt ≥ 40% ≤ 60% of Capital	VL 2027-2029 LT Debt % of Capital	VL 2024 Common Equity % of Capital	VL 2024 Preferred Stock of Capital
#	Abbreviated Utility	UG 490 Company	UG 490 Staff	VL Corporate Name Gas Utility	NYSE Ticker																		
1	Atmos	Yes	Yes	Atmos Energy Corporation	ATO	L	4057157	252684	75-1743247	1-10042	0.85	0.66	17.87	17.20	Yes	Pass	A-	A1	R	40.0%	40.0%	60.0%	0.0%
2	Chesapeake	No	No	Chesapeake Utilities Corporation	CPK	S	4057113	260346	51-0064146	1-11590	0.80	0.60	2.39	1.90	Yes	Pass	W	W	M	42.0%	40.0%	58.0%	0.0%
3	New Jersey	Yes	No	New Jersey Resources Corporation	NJR	M	4057128	291335	22-2376465	1-08359	0.95	0.65	4.21	4.10	Yes	Pass	W	W	M	57.0%	55.0%	42.5%	0.5%
4	NiSource	Yes	Yes	NiSource Inc.	NI	L	4057051	292092	35-1719974	1-09779	0.90	0.48	12.32	10.60	Yes	Pass	BBB+	Baa2	R	57.5%	55.0%	35.0%	7.5%
5	NW Natural	Yes	Yes	Northwest Natural Gas Corporation	NWN	S	4057132	292047	93-0256722	1-15973	0.85	0.56	1.39	1.30	Yes	Pass	A+	Baa1	R	52.5%	50.0%	47.5%	0.0%
6	ONE Gas	Yes	Yes	ONE Gas, Inc.	OGS	M	4427129	243685856	46-3561936	1-36108	0.85	0.64	3.64	3.50	Yes	Pass	A-	A3	R	45.0%	51.0%	55.0%	0.0%
7	South Jersey	No	No	South Jersey Industries, Inc.	SJI	M	4057145	303963	22-1901645	1-06364	0.90	N/A	N/A	4.20	Yes	Pass	W	N/A	M	60.0%	60.0%	40.0%	0.0%
8	Southwest Gas	Yes	Yes	Southwest Gas Holdings, Inc.	SWX	M	4884928	304227	81-3881866	1-37976	0.90	0.35	5.42	4.30	Yes	Pass	BBB-	Baa2	R	58.0%	57.0%	42.0%	0.0%
9	Spire	Yes	Yes	Spire, Inc. (Formerly: The Laclede Group, Inc.)	SR	M	4002506	284847	74-2976504	1-16681	0.85	0.52	3.38	3.30	Yes	Pass	A-	Baa2	R	52.0%	51.0%	44.0%	4.0%
10	UGI	No	No	*UGI Corporation (Propane Focus / VL)	UGI	M	4057537	190756	23-2668356	1-11071	1.10	1.17	5.11	5.00	Fail	Pass	W	W	Fail	60.0%	60.0%	39.0%	1.0%
	TOTAL PEERS	7	6	When Value Line (VL) Beta ratio exceeds 99.9 or earnings are negative, VI shows "NMF" for 'no meaningful figure'.																			
			80% Mid Cap	*UGI Revenue is >35% from Propane / VL																			
	Test Yr 2023			WGL is NOT shown due to purchase by AltaGas																			

R 80% or more of assets are regulated
M 50% - 79% of assets are regulated
W Ratings Withdrawn

Water
XXX UW XXX

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
		Screen:	6	VL Water Utilities passing Staff Peer Screen	80% Mid Cap			Sensitivity Modeling									Either / Or						
		Sensitivities:	0	VL Water Utilities passing Co. Screen																			
		Water Group	Sensitivity			VL Cap Small Mid Large	S&P Global Market Intelligence MI Key	SPCIQ Key	IRS EIN	SEC File	VL 3/28/2024 Beta <1	Yahoo Fin. 3/28/2024 Beta	Yahoo Fin. 3/28/2024 Mkt Cap $ Billions	VL 3/28/2024 Mkt Cap $ Billions	Value Line Water Utility w VL Beta < 1 2/5/2024	VL No Div Declines 5 years	S&P Local LT 3/28/2024 Rating ≥ BBB-	Moody's Local LT 2/23/2024 Rating ≥ Baa3	Last 10-K Highly Regulated LDC Revenue	VL 2024 LT Debt < 56% of Capital	VL 2026-2028 LT Debt % of Capital	VL 2024 Common Equity % of Capital	VL 2024 Preferred Stock of Capital
#	Abbreviated Utility	UW 999 Company	UW 999 Staff	VL Corporate Name Water Utility	NYSE Ticker																		
1	American Water	No	Yes	American Water	AWK	L	4004387	250885	51-0063696	1-34028	0.95	0.62	23.68	25.60	Yes	Pass	A	Baa1	R	57.5%	57.5%	42.5%	0.0%
2	American	No	No	Amer. States Water	AWR	M	4093614	304353	95-4676679	1-14431	0.70	0.42	2.68	3.00	Yes	Pass	A	W	M	46.5%	50.0%	53.5%	0.0%
3	California Water	No	Yes	California Water Service Group	CWT	M	4721056	257568	77-0448994	1-13883	0.75	0.49	2.70	3.00	Yes	Pass	A+	W	R	40.5%	38.0%	59.5%	0.0%
4	Essential Utility	No	No	Essential Util.	WTRG	L	4092620	296276	23-1702594	1-6659	1.00	0.81	10.07	10.10	No	Pass	A-	Baa2	R	52.5%	56.0%	47.5%	0.0%
5	Middlesex Water	No	Yes	Middlesex Water	MSEX	S	4104374	288070	22-1114430	0-422	0.75	0.74	936.887m	1.20	Yes	Pass	A	W	R	41.5%	40.5%	58.5%	0.0%
6	SJW	No	Yes	SJW Group	SJW	M	5000889	301316	77-0066628	1-8966	0.85	0.58	1.82	2.10	Yes	Pass	A-	NR	R	52.5%	43.0%	47.5%	0.0%
	TOTAL PEERS	0	4	When Value Line (VL) Beta ratio exceeds 99.9 or earnings are negative, VI shows "NMF" for 'no meaningful figure'.																			
			80% Mid Cap																				

R 80% or more of assets are regulated
M 50% - 79% of assets are regulated
W Ratings Withdrawn

NWN GRC UG 490 | **Peer Utility Screen** | **Staff/101 Muldoon/2**

Natural Gas

NWN UG 490

1	2	3	4	25	26	27			28
		Screen:	**6**						
		Sensitivities:	**8**						
		Gas Group		**VL**	**Major**	**M&A Activity**			
#	**Abbreviated Utility**	**UG 490 Company**	**UG 490 Staff**	**Div. Growth Rate > 0%**	**M&A in Last 4 Years**	**and General Notes re: Last 4 Years**			**#**
1	Atmos	Yes	Yes	Pass	Pass				1
2	Chesapeake	No	No	Pass	Fail	VL indicates this utility is 72.3% regulated energy operations. 11/7/2022 acquires 100% of Planet Found Energy Development LLC for $9.4 million. 9/26/2023 Agree to acquire Florida City Gas from NextEra for $923 million in Q4 2023.			2
3	New Jersey	Yes	No	Pass	Pass				3
4	NiSource	Yes	Yes	Pass	*Pass	Feb. 2020 Eversource Energy announced a **$1.1 billion acquisition of Columbia Gas of Massachusetts from NiSource**. Feb 29, 2020, NiSource buy Columbia Energy group for $6 billion.			4
5	NW Natural	Yes	Yes	Pass	Pass	October 5, 2022, NWN Water completed the acquisition of the water and wastewater utilities of Far West Water & Sewer, Inc. after closing adjustments, was approximately $97.0 million. 10/2/2023 acquires Rose Valley Water Co.			5
6	ONE Gas	Yes	Yes	Pass	Pass				6
7	South Jersey	No	No	Pass	Fail	**$8.1 billion buyout** of **South Jersey Industries** by Infrastructure Investments Fund pending per S&P			7
8	Southwest Gas	Yes	Yes	Pass	Pass	Carl Icahn Proposes a Hostile Takeover, which Staff discounts because of Utility management and regulatory opposition. On 12/15 SWX announced it will sell MountsinWest Pipelines Holdings Co. to Williams for $1.5 billion in total enterprise value. 2/14/2023 Williams			8
9	Spire	Yes	Yes	Pass	Pass				9
10	UGI	No	No	Pass	Pass	**Very Heavy Propane Position**			10
	TOTAL PEERS	7	6			***20% of Mkt Cap will pass the M&A screen test.**			
			80% Mid Cap						

Test Yr 2023

Water

XXX UW XXX

1	2	3	4	25	26	27			28
		Screen:	**6**						
		Sensitivities:	**0**						
		Water Group	**Sensitivity**	**VL**	**Major**	**M&A Activity**			
#	**Abbreviated Utility**	**UW 999 Company**	**UW 999 Staff**	**Div. Growth Rate > 0%**	**M&A in Last 4 Years**	**and General Notes re: Last 4 Years**			**#**
1	American Water	No	Yes	Pass	Pass	5/27/2023 Pennsylvania American Water, a subsidiary completed a deal with the City of York to acquire the City's wastewater system assets $253.3 million. 32 Acq. Under agreement as of 3/31/2022.			1
2	American	No	No	Pass	Pass				2
3	California Water	No	Yes	Pass	Pass				3
4	Essential Utility	No	No	Pass	Fail	3/16/2020 acquired People's natural Gas for $4.275 billion. 1/3/2023 plan to sell to Hope Gas			4
5	Middlesex Water	No	Yes	Pass	Pass				5
6	SJW	No	Yes	Pass	Pass	2/17/21 SJW TX Subsidiary bought Kendall West and Bandera East water utilities for $23M Annual Report.			6
	TOTAL PEERS	0	4			***20% of Mkt Cap will pass the M&A screen test.**			
			80% Mid Cap						

NWN GRC UG 490 — NWN - Gas Peer Dividends

Last Updated: April 4, 2024

Historical and Near Term VL Dividends, and VL Earnings per Share

Staff/101 Muldoon/3

	#	Abbreviated Utility	UG 490 Company	UG 490 Staff	Ticker	2020 Q1	2020 Q2	2020 Q3	2020 Q4	2020 Yr	2021 Q1	2021 Q2	2021 Q3	2021 Q4	2021 Yr	2022 Q1	2022 Q2	2022 Q3	2022 Q4	2022 Yr	2023 Q1	2023 Q2	2023 Q3	2023 Q4	2023 Yr	2021-23 Average	2024 Yr
		UG 490				Value Line Dividends																				Value Lin
1	1	Atmos	Yes	Yes	ATO	0.575	0.575	0.575	0.625	2.35	0.625	0.625	0.625	0.68	2.555	0.68	0.68	0.68	0.74	2.78	0.74	0.74	0.74	0.805	3.03	2.79	3.22
3	3	New Jersey	Yes	No	NJR	0.3125	0.3125	0.3125	0.3325	1.27	0.3325	0.3325	0.3325	0.3625	1.36	0.3625	0.3625	0.3625	0.3625	1.45	0.39	0.39	0.39	0.39	1.56	1.46	1.68
4	4	NiSource	Yes	Yes	NI	0.21	0.21	0.21	0.21	0.84	0.22	0.22	0.22	0.22	0.88	0.235	0.235	0.235	0.235	0.94	0.25	0.25	0.25	0.25	1.00	0.94	1.06
5	5	NW Natural	Yes	Yes	NWN	0.4775	0.4775	0.4775	0.48	1.91	0.48	0.48	0.48	0.483	1.92	0.483	0.483	0.483	0.485	1.93	0.485	0.485	0.485	0.488	1.94	1.93	1.95
6	6	ONE Gas	Yes	Yes	OGS	0.540	0.54	0.54	0.54	2.16	0.58	0.58	0.58	0.58	2.32	0.62	0.62	0.62	0.62	2.48	0.65	0.65	0.65	0.65	2.60	2.47	2.64
8	8	Southwest Gas	Yes	Yes	SWX	0.545	0.57	0.57	0.57	2.26	0.57	0.595	0.595	0.595	2.36	0.595	0.62	0.62	0.62	2.46	0.62	0.62	0.62	0.62	2.48	2.43	2.48
9	9	Spire	Yes	Yes	SR	0.6225	0.6225	0.6225	0.6225	2.49	0.65	0.65	0.65	0.65	2.60	0.685	0.685	0.685	0.685	2.74	0.72	0.72	0.72	0.72	2.88	2.74	3.02
		TOTAL PEERS	7	6																						
				80% Mid Cap																						

NWN - Gas Peer EPS

Last Updated: April 4, 2024

	#	Abbreviated Utility	UG 490 Company	UG 490 Staff	Ticker	2021 Q1	2021 Q2	2021 Q3	2021 Q4	2021 Yr	2022 Q1	2022 Q2	2022 Q3	2022 Q4	2022 Yr	2023 Q1	2023 Q2	2023 Q3	2023 Q4	2023 Yr	2021-23 Average	2024 Q1	2024 Q2	2024 Q3	2024 Q4	2024 Yr	2025 Q1
		UG 490				Value Line Earnings per Share (EPS)																				Value Line
1	1	Atmos	Yes	Yes	ATO	1.71	2.30	0.78	0.37	5.16	1.86	2.37	0.92	0.51	5.66	1.91	2.48	0.94	0.80	6.13	5.65	2.08	2.53	1.06	0.88	6.55	2.21
3	3	New Jersey	Yes	No	NJR	0.46	1.77	(0.15)	0.07	2.15	0.69	1.36	(0.04)	0.50	2.51	1.14	1.16	0.10	0.30	2.70	2.45	0.74	1.35	0.05	0.66	2.80	0.75
4	4	NiSource	Yes	Yes	NI	0.77	0.13	0.11	0.39	1.40	0.75	0.12	0.10	0.50	1.47	0.77	0.11	0.19	0.53	1.60	1.49	0.85	0.15	0.13	0.57	1.70	0.90
5	5	NW Natural	Yes	Yes	NWN	1.94	(0.02)	(0.67)	1.31	2.56	1.80	0.05	(0.56)	1.36	2.65	2.01	0.03	(0.65)	1.26	2.65	2.62	2.00	0.05	(0.65)	1.35	2.75	2.10
6	6	ONE Gas	Yes	Yes	OGS	1.79	0.56	0.38	1.12	3.85	1.83	0.59	0.44	1.23	4.09	1.84	0.58	0.45	1.28	4.15	4.03	1.82	0.57	0.43	1.23	4.05	1.87
8	8	Southwest Gas	Yes	Yes	SWX	2.03	0.43	(0.19)	1.15	3.42	1.58	(0.10)	(0.18)	(4.18)	(2.88)	0.67	0.40	0.04	1.74	2.85	1.13	1.45	0.55	0.20	1.10	3.30	1.75
9	9	Spire	Yes	Yes	SR	1.65	3.55	0.03	(0.26)	4.97	1.01	3.27	(0.10)	(0.20)	3.98	1.66	3.33	(0.48)	(0.66)	3.85	4.27	1.52	3.34	(0.30)	(0.46)	4.10	1.50
		TOTAL PEERS	7	6																						
				80% Mid Cap																						

NWN - Water Peer Dividends

Sensitivity Modeling — Last Updated: April 4, 2024 — Update Still in Progress

Water Utility Sensitivity Modeling Information is in progress - being updated for Staff R

	#	Abbreviated Utility	UW 999 Company	UW 999 Staff	Ticker	2020 Q1	2020 Q2	2020 Q3	2020 Q4	2020 Yr	2021 Q1	2021 Q2	2021 Q3	2021 Q4	2021 Yr	2022 Q1	2022 Q2	2022 Q3	2022 Q4	2022 Yr	2023 Q1	2023 Q2	2023 Q3	2023 Q4	2023 Yr	2021-23 Average	2024 Yr
		UG 490				Value Line Dividends																				Value Lin
1	10	American Water	No	Yes	AWK	0.50	0.55	0.55	0.55	2.15	0.55	0.6025	0.6025	0.6025	2.36	0.6025	0.655	0.665	0.655	2.58	0.655	0.7075	0.7075	0.7075	2.78	2.57	3.00
3	11	California Water	No	Yes	CWT	0.2125	0.2125	0.2125	0.2125	0.85	0.230	0.230	0.230	0.230	0.92	0.250	0.250	0.250	0.250	1.00	0.260	0.260	0.260	0.260	1.04	0.99	1.12
5	12	Middlesex Water	No	Yes	MSEX	0.2562	0.2562	0.2562	0.2725	1.04	0.2725	0.2725	0.2725	0.29	1.11	0.29	0.29	0.29	0.3125	1.18	0.3125	0.3125	0.3125	0.325	1.26	1.18	1.32
6	13	SJW	No	Yes	SJW	0.32	0.32	0.32	0.32	1.28	0.34	0.34	0.34	0.34	1.36	0.36	0.36	0.36	0.36	1.44	0.38	0.38	0.38	0.38	1.52	1.44	1.60
		TOTAL PEERS	0	4																						
				80% Mid Cap																						

NWN - Water Peer EPS

Sensitivity Modeling — Last Updated: April 4, 2024 — Update Still in Progress

Water Utility Sensitivity Modeling Information is in progress - being updated for Staff R

	#	Abbreviated Utility	UW 999 Company	UW 999 Staff	Ticker	2021 Q1	2021 Q2	2021 Q3	2021 Q4	2021 Yr	2022 Q1	2022 Q2	2022 Q3	2022 Q4	2022 Yr	2023 Q1	2023 Q2	2023 Q3	2023 Q4	2023 Yr	2021-23 Average	2024 Q1	2024 Q2	2024 Q3	2024 Q4	2024 Yr	2025 Q1
		UG 490				Value Line Earnings per Share (EPS)																				Value Line
1	10	American Water	No	Yes	AWK	0.73	1.14	1.53	3.55	6.95	0.87	1.20	1.63	0.81	4.51	0.91	1.44	1.66	0.79	4.80	5.42	0.95	1.50	1.85	0.85	5.15	
3	11	California Water	No	Yes	CWT	(0.06)	0.75	1.20	0.07	1.96	0.02	0.36	1.03	0.35	1.76	(0.40)	0.17	0.60	0.43	0.80	1.51	0.15	0.60	1.00	0.50	2.25	
5	12	Middlesex Water	No	Yes	MSEX	0.39	0.62	0.65	0.41	2.07	0.68	0.50	0.80	0.40	2.38	0.33	0.55	0.56	0.61	2.05	2.17	0.50	0.65	0.75	0.65	2.55	
6	13	SJW	No	Yes	SJW	0.09	0.69	0.64	0.60	2.02	0.12	0.38	0.82	1.09	2.41	0.37	0.58	1.13	0.87	2.95	2.46	0.45	0.60	1.20	0.90	3.15	
		TOTAL PEERS	0	4																						
				80% Mid Cap																						

NWN GRC UG 490

Staff/101 Muldoon/3

NWN - Gas Peer Dividends

Historical and Near Term VL Dividends, and

	1	2	3	4	5	28	29	30	31	32	33	34	35	
	UG 490					e Estimated Near Future Dividends					VL Avg.	Div Growth		
	#	Abbreviated Utility	UG 490 Company	UG 490 Staff	Ticker	2025 Yr	2026 Yr	2027 Yr	2028 Yr	2029 Yr	2027 - 29 / Yr	2027-29 vs. 2021-23	#	
1	1	Atmos	Yes	Yes	ATO	3.46	3.53	3.87	4.25	4.63	4.25	7.3%	1	1
3	3	New Jersey	Yes	No	NJR	1.76	1.77	1.86	1.95	2.04	1.95	5.0%	3	3
4	4	NiSource	Yes	Yes	NI	1.12	1.10	1.15	1.20	1.25	1.20	4.2%	4	4
5	5	NW Natural	Yes	Yes	NWN	1.96	1.96	1.97	1.98	1.99	1.98	0.4%	5	5
6	6	ONE Gas	Yes	Yes	OGS	2.68	2.71	2.78	2.85	2.92	2.85	2.4%	6	6
8	8	Southwest Gas	Yes	Yes	SWX	2.52	2.52	2.56	2.60	2.64	2.60	1.1%	8	8
9	9	Spire	Yes	Yes	SR	3.16	3.20	3.40	3.60	3.80	3.60	4.7%	9	9
		TOTAL PEERS	7	6							Staff Gas Screen	3.3%	Mean	
				80% Mid Cap							Company Peer Screen	3.6%		

NWN - Gas Peer EPS

	1	2	3	4	5	27	28	29	30	31	32	33	34	35	36	37	38	
	UG 490					e Estimated Near Future Earnings per Share in Blue								VL Avg	EPS Growth VL Avg			
	#	Abbreviated Utility	UG 490 Company	UG 490 Staff	Ticker	2025 Q2	2025 Q3	2025 Q4	2025 Yr	2026 Yr	2027 Yr	2028 Yr	2029 Yr	2027- 29 / Yr	2027-29 vs. 2021-23	#	
1	1	Atmos	Yes	Yes	ATO	2.65	1.17	0.97	7.00	7.42	7.87	8.35	8.83	8.35	6.7%	1	1
3	3	New Jersey	Yes	No	NJR	1.40	0.05	0.70	2.90	3.09	3.29	3.50	3.71	3.50	6.1%	3	3
4	4	NiSource	Yes	Yes	NI	0.20	0.15	0.60	1.85	1.93	2.01	2.10	2.19	2.10	5.9%	4	4
5	5	NW Natural	Yes	Yes	NWN	0.05	(0.60)	1.45	3.00	3.08	3.16	3.25	3.34	3.25	3.7%	5	5
6	6	ONE Gas	Yes	Yes	OGS	0.60	0.48	1.25	4.20	4.45	4.72	5.00	5.28	5.00	3.7%	6	6
8	8	Southwest Gas	Yes	Yes	SWX	0.65	0.15	1.65	4.20	4.22	4.23	4.25	4.27	4.25	24.7%	8	8
9	9	Spire	Yes	Yes	SR	3.35	(0.11)	(0.24)	4.50	4.81	5.14	5.50	5.86	5.50	4.3%	9	9
		TOTAL PEERS	7	6									Staff Gas Screen	8.2%	Mean		
				80% Mid Cap									Company Peer Screen	7.9%			

ebuttal Testimony VL 27-29 Estimates Not Yet Available.

NWN - Water Peer Dividends

	1	2	3	4	5	28	29	30	31	32	33	34	35	
	UG 490					e Estimated Near Future Dividends					VL Avg.	Div Growth		
	#	Abbreviated Utility	UW 999 Company	UW 999 Staff	Ticker	2025 Yr	2026 Yr	2027 Yr	2028 Yr	2029 Yr	2027 - 29 / Yr	2027-29 vs. 2021-23	#	
1	10	American Water	No	Yes	AWK		0.00	0.00	0.00	0.00		-100.0%	10	1
3	11	California Water	No	Yes	CWT		0.00	0.00	0.00	0.00		-100.0%	11	3
5	12	Middlesex Water	No	Yes	MSEX		0.00	0.00	0.00	0.00		-100.0%	12	5
6	13	SJW	No	Yes	SJW		0.00	0.00	0.00	0.00		-100.0%	13	6
		TOTAL PEERS	0	4							Staff Water Screen	-100.0%	Mean	
				80% Mid Cap							Company Peer Screen	#N/A		

ebuttal Testimony VL 27-29 Estimates Not Yet Available.

NWN - Water Peer EPS

	1	2	3	4	5	28	29	30	31	32	33	34	35	36	37	38	
	UG 490					e Estimated Near Future Earnings per Share in Blue								VL Avg	EPS Growth VL Avg		
	#	Abbreviated Utility	UW 999 Company	UW 999 Staff	Ticker	2025 Q2	2025 Q3	2025 Q4	2025 Yr	2026 Yr	2027 Yr	2028 Yr	2029 Yr	2027- 29 / Yr	2027-29 vs. 2021-23	#	
1	10	American Water	No	Yes	AWK				0.00	#DIV/0!	#DIV/0!	0.00	#DIV/0!		-100.0%	10	1
3	11	California Water	No	Yes	CWT				0.00	#DIV/0!	#DIV/0!	0.00	#DIV/0!		-100.0%	11	3
5	12	Middlesex Water	No	Yes	MSEX				0.00	#DIV/0!	#DIV/0!	0.00	#DIV/0!		-100.0%	12	5
6	13	SJW	No	Yes	SJW				0.00	#DIV/0!	#DIV/0!	0.00	#DIV/0!		-100.0%	13	6
		TOTAL PEERS	0	4									Staff Gas Screen		-100.0%	Mean	
				80% Mid Cap									Company Peer Screen		#N/A		

NWN GRC UG 490 | **Staff Hamada Adjustments** | **Staff/101 Muldoon/4**

NWN GRC
UG 490 Staff Hamada Adjustments

	1	2	3	4	5	6	7	8	9	10	11	#	13	14	15	16	17	18	#	20	21	22
						Yahoo Finance Q1 2024							VL 2024 Cap Structure									
						$ Stock Closing Price			3-Day	Div Yield	VL 2024		%	%		2024	Hamada	Relevered		Equity	Hamada Adjustment	
						1st Trading Day of Month			Avg $	at	Return on		Long-Term	Common	VL	VL	Unlevered	Beta		Risk	Equity	
	#	Abbreviated Utility	UG 490 Company	UG 490 Staff	Ticker	Feb. 2/1/2023	Mar. 3/1/2024	Apr. 4/1/2024	Stock Price	Recent Price	Common Equity		Debt	Equity	Beta	Tax Rate	Beta	Equity at 50.0%		Premium	At 50.0%	#
1	1	Atmos	Yes	Yes	ATO	112.91	118.87	116.23	116.00	2.6%	8.5%		40.0	60.0	0.85	12.0%	0.54	1.01		4.20%	0.66%	1
3	3	New Jersey	Yes	No	NJR	41.61	42.91	42.78	42.43	3.7%	11.5%		57.0	43.0	0.95	22.0%	0.47	0.83		4.20%	-0.50%	3
4	4	NiSource	Yes	Yes	NI	26.06	27.66	27.19	26.97	3.7%	9.5%		57.5	37.5	0.90	19.0%	0.40	0.73		4.20%	-0.73%	4
5	5	NW Natural	Yes	Yes	NWN	36.74	37.22	26.41	33.46	5.8%	8.0%		52.5	47.5	0.85	25.0%	0.46	0.81		4.20%	-0.15%	5
6	6	ONE Gas	Yes	Yes	OGS	59.60	64.53	63.72	62.62	4.2%	8.5%		45.0	55.0	0.85	16.5%	0.50	0.93		4.20%	0.32%	6
8	8	Southwest Gas	Yes	Yes	SWX	68.15	76.13	74.54	72.94	3.4%	6.5%		58.0	42.0	0.90	21.0%	0.43	0.77		4.20%	-0.54%	8
9	9	Spire	Yes	Yes	SR	59.32	61.37	59.34	60.01	4.8%	8.0%		52.0	44.0	0.85	19.0%	0.43	0.79		4.20%	-0.27%	9
		TOTAL PEERS	7	6		Dividend Yield = (Annual Dividends per Share) / Price per Share												Staff Gas Screen			-0.1%	Mean
				80% Mid Cap		When Value Line (VL) Beta ratio exceeds 99.9 or earnings are negative, VI shows "NMF" for 'no meaningful figure'.												Company Peer Screen			-0.2%	

Water **Sensitivity Modeling**
UG 490 Staff Hamada Adjustments

	1	2	3	4	5	6	7	8	9	10	11	#	13	14	15	16	17	18	#	20	21	22
						Yahoo Finance Q1 2024							VL 2024 Cap Structure									
						$ Stock Closing Price			3-Day	Div Yield	VL 2024		%	%		2024	Hamada	Relevered		Equity	Hamada Adjustment	
						1st Trading Day of Month			Avg $	at	Return on		Long-Term	Common	VL	VL	Unlevered	Beta		Risk	Equity	
	#	Abbreviated Utility	UW 999 Company	UW 999 Staff	Ticker	Feb. 2/1/2023	Mar. 3/1/2024	Apr. 4/1/2024	Stock Price	Recent Price	Common Equity		Debt	Equity	Beta	Tax Rate	Beta	Equity at 50.0%		Premium	At 50.0%	#
1	10	American Water	No	Yes	AWK	118.54	122.21	118.52	119.76	2.3%	9.50%		57.5	42.5	0.95	21.0%	0.46	0.82		4.20%	-0.54%	1
3	11	California Water	No	Yes	CWT	45.89	46.48	45.76	46.04	2.3%	8.50%		40.5	59.5	0.75	21.0%	0.49	0.87		4.20%	0.52%	3
5	12	Middlesex Water	No	Yes	MSEX	50.89	52.50	48.26	50.55	2.5%	11.00%		41.5	58.5	0.75	21.0%	0.48	0.86		4.20%	0.46%	5
6	13	SJW	No	Yes	SJW	55.06	56.59	54.45	55.37	2.7%	7.50%		52.5	47.5	0.85	21.0%	0.45	0.81		4.20%	-0.16%	6
		TOTAL PEERS	0	4		Dividend Yield = (Annual Dividends per Share) / Price per Share												Staff Gas Screen			0.1%	Mean
				80% Mid Cap		When Value Line (VL) Beta ratio exceeds 99.9 or earnings are negative, VI shows "NMF" for 'no meaningful figure'.												Company Peer Screen			#N/A	

CASE: UG 490
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

ROE – Three-Stage DCF:
Models X and Y

April 18, 2024

4.46% Annual Growth Rate - Stage 3

Dividend Growth with Terminal Value as Perpetuity

E.O.Y. Cash Flows — Staff — UG 490 — Model X

	#	Abbreviated Utility	UG 490 Company	UG 490 Staff	UG 490 Staff Sensitivity	IRR	Terminal Value as % of NPV$_{DIV}$	NPV @ IRR	Recent Price*	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2052 Terminal Value	2053 Div	2053 Perpetuity	#
										Initial Stage					Transition Stage					Final Stage																						
1	1	Atmos	Yes	Yes	Yes	7.9%	40.5%	0.00	(116.00)	3.22	3.46	3.53	3.87	4.25	4.63	4.97	5.34	5.72	6.13	6.40	6.69	6.99	7.30	7.62	7.96	8.32	8.69	9.08	9.48	9.90	10.35	10.81	11.29	11.79	12.32	12.87	13.44	14.04	459.93	14.67	445.26	1
2	3	New Jersey	Yes	No	No	8.4%	34.3%	(0.00)	(42.43)	1.68	1.76	1.77	1.86	1.95	2.04	2.15	2.26	2.37	2.49	2.60	2.72	2.84	2.96	3.10	3.23	3.38	3.53	3.69	3.85	4.02	4.20	4.39	4.59	4.79	5.00	5.23	5.46	5.70	163.78	5.96	157.82	3
3	4	NiSource	Yes	Yes	Yes	8.2%	36.0%	0.00	(26.97)	1.06	1.12	1.10	1.15	1.20	1.25	1.30	1.36	1.41	1.47	1.54	1.61	1.68	1.75	1.83	1.91	2.00	2.09	2.18	2.28	2.38	2.49	2.60	2.71	2.84	2.96	3.09	3.23	3.38	102.70	3.53	99.17	4
4	5	NW Natural	Yes	Yes	Yes	8.8%	28.3%	0.00	(33.46)	1.95	1.96	1.96	1.97	1.98	1.99	2.00	2.01	2.01	2.02	2.11	2.21	2.31	2.41	2.52	2.63	2.75	2.87	3.00	3.13	3.27	3.42	3.57	3.73	3.89	4.07	4.25	4.44	4.64	120.25	4.84	115.41	5
5	6	ONE Gas	Yes	Yes	Yes	8.0%	36.6%	0.00	(62.62)	2.64	2.68	2.71	2.78	2.85	2.92	3.00	3.07	3.15	3.23	3.37	3.52	3.68	3.84	4.01	4.19	4.38	4.57	4.78	4.99	5.21	5.45	5.69	5.94	6.21	6.48	6.77	7.08	7.39	233.09	7.72	225.37	6
6	8	Southwest Gas	Yes	Yes	Yes	7.1%	46.6%	0.00	(72.94)	2.48	2.52	2.52	2.56	2.60	2.64	2.67	2.70	2.73	2.77	2.89	3.02	3.15	3.29	3.44	3.60	3.76	3.92	4.10	4.28	4.47	4.67	4.88	5.10	5.32	5.56	5.81	6.07	6.34	267.23	6.62	260.61	8
7	9	Spire	Yes	Yes	Yes	9.6%	25.2%	0.00	(60.01)	3.02	3.16	3.20	3.40	3.60	3.80	3.99	4.18	4.37	4.58	4.78	4.99	5.22	5.45	5.69	5.95	6.21	6.49	6.78	7.08	7.40	7.73	8.07	8.43	8.81	9.20	9.61	10.04	10.49	234.76	10.95	223.81	9
8	10	American Water	No	No	Yes	N/A	N/A	N/A	(119.76)	3.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	#VALUE!	0.00	#VALUE!	10
9	11	California Water	No	No	Yes	N/A	N/A	N/A	(46.04)	1.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	#VALUE!	0.00	#VALUE!	11
10	12	Middlesex Water	No	No	Yes	N/A	N/A	N/A	(50.55)	1.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	#VALUE!	0.00	#VALUE!	12
11	13	SJW	No	No	Yes	N/A	N/A	N/A	(55.37)	1.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	#VALUE!	0.00	#VALUE!	13
		TOTAL PEERS	7	6	10		Mean																																		
				80% Mid Cap		8.27%	35.52%	0.00	Staff Gas Screen																																	
						N/A	35.52%	0.00	Staff Gas and Water Sensitivity Screen																																	
						8.29%	35.35%	(0.00)	Company Peer Screen																																	

Staff will update Water Sensitivity in Staff Rebuttal Testimony

B.O.Y. Cash Flows — Staff — UG 490 — Model X

	#	Abbreviated Utility	UG 490 Company	UG 490 Staff	UG 490 Staff Sensitivity	IRR	Terminal Value as % of NPV$_{DIV}$	NPV @ IRR	Recent Price*	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2052 Terminal Value	2053 Div	2053 Perpetuity	#
										Initial Stage					Transition Stage					Final Stage																						
1	1	Atmos	Yes	Yes	Yes	8.1%	38.5%	(0.00)	(116.00)	3.46	3.53	3.87	4.25	4.63	4.97	5.34	5.72	6.13	6.40	6.69	6.99	7.30	7.62	7.96	8.32	8.69	9.08	9.48	9.90	10.35	10.81	11.29	11.79	12.32	12.87	13.44	14.04	14.67	458.33	15.32	443.01	1
2	3	New Jersey	Yes	No	No	8.6%	32.7%	0.00	(42.43)	1.76	1.77	1.86	1.95	2.04	2.15	2.26	2.37	2.49	2.60	2.72	2.84	2.96	3.10	3.23	3.38	3.53	3.69	3.85	4.02	4.20	4.39	4.59	4.79	5.00	5.23	5.46	5.70	5.96	164.11	6.22	157.89	3
3	4	NiSource	Yes	Yes	Yes	8.3%	34.6%	(0.00)	(26.97)	1.12	1.10	1.15	1.20	1.25	1.30	1.36	1.41	1.47	1.54	1.61	1.68	1.75	1.83	1.91	2.00	2.09	2.18	2.28	2.38	2.49	2.60	2.71	2.84	2.96	3.09	3.23	3.38	3.53	103.03	3.68	99.34	4
4	5	NW Natural	Yes	Yes	Yes	9.0%	27.6%	0.00	(33.46)	1.96	1.96	1.97	1.98	1.99	2.00	2.01	2.01	2.02	2.11	2.21	2.31	2.41	2.52	2.63	2.75	2.87	3.00	3.13	3.27	3.42	3.57	3.73	3.89	4.07	4.25	4.44	4.64	4.84	121.90	5.06	116.85	5
5	6	ONE Gas	Yes	Yes	Yes	8.2%	35.4%	0.00	(62.62)	2.68	2.71	2.78	2.85	2.92	3.00	3.07	3.15	3.23	3.37	3.52	3.68	3.84	4.01	4.19	4.38	4.57	4.78	4.99	5.21	5.45	5.69	5.94	6.21	6.48	6.77	7.08	7.39	7.72	234.64	8.07	226.58	6
6	8	Southwest Gas	Yes	Yes	Yes	7.2%	45.6%	0.00	(72.94)	2.52	2.52	2.56	2.60	2.64	2.67	2.70	2.73	2.77	2.89	3.02	3.15	3.29	3.44	3.60	3.76	3.92	4.10	4.28	4.47	4.67	4.88	5.10	5.32	5.56	5.81	6.07	6.34	6.62	269.14	6.92	262.22	8
7	9	Spire	Yes	Yes	Yes	9.8%	23.7%	0.00	(60.01)	3.16	3.20	3.40	3.60	3.80	3.99	4.18	4.37	4.58	4.78	4.99	5.22	5.45	5.69	5.95	6.21	6.49	6.78	7.08	7.40	7.73	8.07	8.43	8.81	9.20	9.61	10.04	10.49	10.95	235.14	11.44	223.70	9
8	10	American Water	No	No	Yes	N/A	N/A	N/A	(119.76)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	#VALUE!	0.00	#VALUE!	10
9	11	California Water	No	No	Yes	N/A	N/A	N/A	(46.04)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	#VALUE!	0.00	#VALUE!	11
10	12	Middlesex Water	No	No	Yes	N/A	N/A	N/A	(50.55)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	#VALUE!	0.00	#VALUE!	12
11	13	SJW	No	No	Yes	N/A	N/A	N/A	(55.37)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	#VALUE!	0.00	#VALUE!	13
		TOTAL PEERS	7	6	10		Mean																																		
				80% Mid Cap		8.43%	34.23%	(0.00)	Staff Gas Screen																																	
						N/A	34.23%	(0.00)	Staff Gas and Water Sensitivity Screen																																	
						8.45%	34.01%	(0.00)	Company Peer Screen																																	

Staff will update Water Sensitivity in Staff Rebuttal Testimony

Average B.O.Y. & E.O.Y. Cash Flows — Model X

	#	Abbreviated Utility	UG 490 Company	UG 490 Staff	UG 490 Staff Sensitivity	Average IRR	Terminal Value as % of NPV$_{DIV}$	Average 2023 - 2027 Dividend Growth Rates EOY	BOY	Average	#
1	1	Atmos	Yes	Yes	Yes	8.0%	39.5%	7.2%	7.5%	7.4%	1
2	3	New Jersey	Yes	No	No	8.5%	33.6%	3.8%	3.8%	3.8%	3
3	4	NiSource	Yes	Yes	Yes	8.3%	35.3%	3.1%	2.8%	3.0%	4
4	5	NW Natural	Yes	Yes	Yes	8.9%	27.9%	0.4%	0.4%	0.4%	5
5	6	ONE Gas	Yes	Yes	Yes	8.1%	36.0%	1.9%	2.2%	2.1%	6
6	8	Southwest Gas	Yes	Yes	Yes	7.2%	46.1%	1.2%	1.2%	1.2%	8
7	9	Spire	Yes	Yes	Yes	9.7%	24.4%	4.5%	4.8%	4.6%	9
8	10	American Water	No	No	Yes	N/A	N/A	-100.0%	#DIV/0!	#DIV/0!	10
9	11	California Water	No	No	Yes	N/A	N/A	-100.0%	#DIV/0!	#DIV/0!	11
10	12	Middlesex Water	No	No	Yes	N/A	N/A	-100.0%	#DIV/0!	#DIV/0!	12
11	13	SJW	No	No	Yes	N/A	N/A	-100.0%	#DIV/0!	#DIV/0!	13
		TOTAL PEERS	7	6	10		Mean				
				80% Mid Cap		8.36%	34.88%	3.09%	Staff Gas Screen		
						N/A	34.88%	#DIV/0!	Staff Gas and Water Sensitivity Screen		
						8.37%	34.68%	3.19%	Company Peer Screen		

Staff will update Water Sensitivity in Staff Rebuttal Testimony

4.58% Annual Growth Rate - Stage 3

EPS Growth to Determine a Sale Terminal EPS Growth

E.O.Y. Cash Flows

Staff UG 490 Model Y

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	
							Terminal Value as			2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2052				
	#	Abbreviated Utility	UG 490 Company	UG 490 Staff	UG 490 Staff Sensitivity	IRR	% of NPV_{DIV}	NPV @ IRR	Recent Price*	Initial Stage					Transition Stage					Final Stage																				Terminal Value	2053 Div	2053 Sale	2054	#
1	1	Atmos	Yes	Yes	Yes	8.2%	42.9%	0.00	(116.00)	3.22	3.46	3.53	3.87	4.25	4.63	4.97	5.34	5.72	6.13	6.40	6.69	6.99	7.30	7.62	7.96	8.32	8.69	9.08	9.48	9.90	10.35	10.81	11.29	11.79	12.32	12.87	13.44	14.04	534.40	14.68	519.71		1
				e						7.00	7.42	7.87	8.35	8.83	9.44	10.09	10.77	11.49	12.25	12.81	13.39	14.01	14.65	15.32	16.02	16.75	17.52	18.32	19.16	20.04	20.96	21.92	22.92	23.97	25.07	26.22	27.42	28.67		29.99		31.36	
2	3	New Jersey	Yes	No	No	8.7%	36.8%	0.00	(42.43)	1.68	1.76	1.77	1.86	1.95	2.04	2.15	2.26	2.37	2.49	2.60	2.72	2.84	2.96	3.10	3.23	3.38	3.53	3.69	3.85	4.02	4.20	4.39	4.59	4.79	5.00	5.23	5.46	5.70	193.54	5.97	187.58		3
				e						2.90	3.09	3.29	3.50	3.71	3.95	4.19	4.45	4.72	5.01	5.23	5.47	5.73	5.99	6.26	6.55	6.85	7.16	7.49	7.83	8.19	8.57	8.96	9.37	9.80	10.25	10.72	11.21	11.72		12.26		12.82	
3	4	NiSource	Yes	Yes	Yes	8.4%	37.4%	-	(26.97)	1.06	1.12	1.10	1.15	1.20	1.25	1.30	1.36	1.41	1.47	1.54	1.61	1.68	1.75	1.83	1.91	2.00	2.09	2.18	2.28	2.38	2.49	2.60	2.71	2.84	2.96	3.09	3.23	3.38	112.53	3.53	109.00		4
				e						1.85	1.93	2.01	2.10	2.19	2.32	2.46	2.61	2.76	2.92	3.05	3.19	3.34	3.49	3.65	3.82	3.99	4.18	4.37	4.57	4.78	5.00	5.23	5.46	5.72	5.98	6.25	6.54	6.84		7.15		7.48	
4	5	NW Natural	Yes	Yes	Yes	8.8%	28.2%	0.00	(33.46)	1.95	1.96	1.96	1.97	1.98	1.99	2.00	2.01	2.01	2.02	2.11	2.21	2.31	2.41	2.52	2.63	2.75	2.87	3.00	3.13	3.27	3.42	3.57	3.73	3.89	4.07	4.25	4.44	4.64	119.33	4.85	114.48		5
				e						3.00	3.08	3.16	3.25	3.34	3.46	3.59	3.73	3.87	4.01	4.19	4.38	4.58	4.79	5.01	5.24	5.48	5.74	6.00	6.27	6.56	6.86	7.17	7.50	7.85	8.21	8.58	8.97	9.39		9.82		10.27	
5	6	ONE Gas	Yes	Yes	Yes	8.2%	37.7%	0.00	(62.62)	2.64	2.68	2.71	2.78	2.85	2.92	3.00	3.07	3.15	3.23	3.37	3.52	3.68	3.84	4.01	4.19	4.38	4.57	4.78	4.99	5.21	5.45	5.69	5.94	6.21	6.48	6.77	7.08	7.39	250.14	7.73	242.41		6
				e						4.20	4.45	4.72	5.00	5.28	5.48	5.69	5.90	6.12	6.35	6.64	6.94	7.26	7.59	7.94	8.31	8.69	9.08	9.50	9.94	10.39	10.87	11.36	11.88	12.43	13.00	13.59	14.22	14.87		15.55		16.26	
6	8	Southwest Gas	Yes	Yes	Yes	8.9%	56.3%	0.00	(72.94)	2.48	2.52	2.52	2.56	2.60	2.64	2.67	2.70	2.73	2.77	2.89	3.02	3.15	3.29	3.44	3.60	3.76	3.92	4.10	4.28	4.47	4.67	4.88	5.10	5.32	5.56	5.81	6.07	6.34	533.71	6.63	527.08		8
				e						4.20	4.22	4.23	4.25	4.27	5.32	6.58	8.07	9.82	11.85	12.39	12.96	13.55	14.18	14.82	15.50	16.21	16.96	17.73	18.54	19.39	20.28	21.21	22.18	23.20	24.26	25.37	26.53	27.75		29.02		30.35	
7	9	Spire	Yes	Yes	Yes	9.7%	26.5%	0.00	(60.01)	3.02	3.16	3.20	3.40	3.60	3.80	3.99	4.18	4.37	4.58	4.78	4.99	5.22	5.45	5.69	5.95	6.21	6.49	6.78	7.08	7.40	7.73	8.07	8.43	8.81	9.20	9.61	10.04	10.49	259.10	10.97	248.13		9
				e						4.50	4.81	5.14	5.50	5.86	6.12	6.39	6.67	6.96	7.27	7.60	7.95	8.31	8.69	9.09	9.50	9.94	10.40	10.87	11.37	11.89	12.43	13.00	13.60	14.22	14.87	15.56	16.27	17.01		17.79		18.61	
8	10	American Water	No	No	Yes	N/A	N/A	N/A	(119.76)	3.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	#DIV/0!	0.00	#DIV/0!		10
				e						0.00	#DIV/0!	#DIV/0!	0.00	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!		#DIV/0!		#DIV/0!	
9	11	California Water	No	No	Yes	N/A	N/A	N/A	(46.04)	1.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	#DIV/0!	0.00	#DIV/0!		11
				e						0.00	#DIV/0!	#DIV/0!	0.00	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!		#DIV/0!		#DIV/0!	
10	12	Middlesex Water	No	No	Yes	N/A	N/A	N/A	(50.55)	1.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	#DIV/0!	0.00	#DIV/0!		12
				e						0.00	#DIV/0!	#DIV/0!	0.00	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!		#DIV/0!		#DIV/0!	
11	13	SJW	No	No	Yes	N/A	N/A	N/A	(55.37)	1.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	#DIV/0!	0.00	#DIV/0!		13
				e						0.00	#DIV/0!	#DIV/0!	0.00	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!		#DIV/0!		#DIV/0!	
		TOTAL PEERS	7	6	10																																						
				80% Mid Cap																																								

	Mean		
8.71%	38.17%	0.00	Staff Gas Screen
N/A	38.17%	0.00	Staff Gas and Water Sensitivity Screen
8.72%	37.97%	0.00	Company Peer Screen

Staff will update Water Sensitivity in Staff Rebuttal Testimony

B.O.Y. Cash Flows — Staff Model Y — EPS Growth

#	Abbreviated Utility	UG 490 Company	UG 490 Staff	UG 490 Staff Sensitivity	IRR	Terminal Value as % of NPV_{DIV}	NPV @ IRR	Recent Price*	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2052 Terminal Value	2053 Div	2053 Sale	2054	#
									Initial Stage					Transition Stage					Final Stage																							
1	1	Atmos	Yes	Yes	Yes	8.4%	40.9%	0.00	(116.00)	3.46	3.53	3.87	4.25	4.63	4.97	5.34	5.72	6.13	6.40	6.69	6.99	7.30	7.62	7.96	8.32	8.69	9.08	9.48	9.90	10.35	10.81	11.29	11.79	12.32	12.87	13.44	14.04	14.68	535.07	15.36	519.71		1
				e					7.00	7.42	7.87	8.35	8.83	9.44	10.09	10.77	11.49	12.25	12.81	13.39	14.01	14.65	15.32	16.02	16.75	17.52	18.32	19.16	20.04	20.96	21.92	22.92	23.97	25.07	26.22	27.42	28.67		29.99		31.36	
2	3	New Jersey	Yes	No	No	8.9%	35.2%	0.00	(42.43)	1.76	1.77	1.86	1.95	2.04	2.15	2.26	2.37	2.49	2.60	2.72	2.84	2.96	3.10	3.23	3.38	3.53	3.69	3.85	4.02	4.20	4.39	4.59	4.79	5.00	5.23	5.46	5.70	5.97	193.82	6.24	187.58		3
				e					2.90	3.09	3.29	3.50	3.71	3.95	4.19	4.45	4.72	5.01	5.23	5.47	5.73	5.99	6.26	6.55	6.85	7.16	7.49	7.83	8.19	8.57	8.96	9.37	9.80	10.25	10.72	11.21	11.72		12.26		12.82	
3	4	NiSource	Yes	Yes	Yes	8.5%	35.9%	0.00	(26.97)	1.12	1.10	1.15	1.20	1.25	1.30	1.36	1.41	1.47	1.54	1.61	1.68	1.75	1.83	1.91	2.00	2.09	2.18	2.28	2.38	2.49	2.60	2.71	2.84	2.96	3.09	3.23	3.38	3.53	112.69	3.69	109.00		4
				e					1.85	1.93	2.01	2.10	2.19	2.32	2.46	2.61	2.76	2.92	3.05	3.19	3.34	3.49	3.65	3.82	3.99	4.18	4.37	4.57	4.78	5.00	5.23	5.46	5.72	5.98	6.25	6.54	6.84		7.15		7.48	
4	5	NW Natural	Yes	Yes	Yes	8.9%	27.3%	0.00	(33.46)	1.96	1.96	1.97	1.98	1.99	2.00	2.01	2.01	2.02	2.11	2.21	2.31	2.41	2.52	2.63	2.75	2.87	3.00	3.13	3.27	3.42	3.57	3.73	3.89	4.07	4.25	4.44	4.64	4.85	119.55	5.07	114.48		5
				e					3.00	3.08	3.16	3.25	3.34	3.46	3.59	3.73	3.87	4.01	4.19	4.38	4.58	4.79	5.01	5.24	5.48	5.74	6.00	6.27	6.56	6.86	7.17	7.50	7.85	8.21	8.58	8.97	9.39		9.82		10.27	
5	6	ONE Gas	Yes	Yes	Yes	8.3%	36.4%	0.00	(62.62)	2.68	2.71	2.78	2.85	2.92	3.00	3.07	3.15	3.23	3.37	3.52	3.68	3.84	4.01	4.19	4.38	4.57	4.78	4.99	5.21	5.45	5.69	5.94	6.21	6.48	6.77	7.08	7.39	7.73	250.49	8.08	242.41		6
				e					4.20	4.45	4.72	5.00	5.28	5.48	5.69	5.90	6.12	6.35	6.64	6.94	7.26	7.59	7.94	8.31	8.69	9.08	9.50	9.94	10.39	10.87	11.36	11.88	12.43	13.00	13.59	14.22	14.87		15.55		16.26	
6	8	Southwest Gas	Yes	Yes	Yes	9.0%	55.4%	0.00	(72.94)	2.52	2.52	2.56	2.60	2.64	2.67	2.70	2.73	2.77	2.89	3.02	3.15	3.29	3.44	3.60	3.76	3.92	4.10	4.28	4.47	4.67	4.88	5.10	5.32	5.56	5.81	6.07	6.34	6.63	534.01	6.93	527.08		8
				e					4.20	4.22	4.23	4.25	4.27	5.32	6.58	8.07	9.82	11.85	12.39	12.96	13.55	14.18	14.82	15.50	16.21	16.96	17.73	18.54	19.39	20.28	21.21	22.18	23.20	24.26	25.37	26.53	27.75		29.02		30.35	
7	9	Spire	Yes	Yes	Yes	10.0%	25.0%	0.00	(60.01)	3.16	3.20	3.40	3.60	3.80	3.99	4.18	4.37	4.58	4.78	4.99	5.22	5.45	5.69	5.95	6.21	6.49	6.78	7.08	7.40	7.73	8.07	8.43	8.81	9.20	9.61	10.04	10.49	10.97	259.60	11.47	248.13		9
				e					4.50	4.81	5.14	5.50	5.86	6.12	6.39	6.67	6.96	7.27	7.60	7.95	8.31	8.69	9.09	9.50	9.94	10.40	10.87	11.37	11.89	12.43	13.00	13.60	14.22	14.87	15.56	16.27	17.01		17.79		18.61	
8	10	American Water	No	No	Yes	N/A	N/A	N/A	(119.76)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	#DIV/0!	0.00	#DIV/0!		10
				e					0.00	#DIV/0!	#DIV/0!	0.00	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!		#DIV/0!		#DIV/0!	
9	11	California Water	No	No	Yes	N/A	N/A	N/A	(46.04)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	#DIV/0!	0.00	#DIV/0!		11
				e					0.00	#DIV/0!	#DIV/0!	0.00	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!		#DIV/0!		#DIV/0!	
10	12	Middlesex Water	No	No	Yes	N/A	N/A	N/A	(50.55)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	#DIV/0!	0.00	#DIV/0!		12
				e					0.00	#DIV/0!	#DIV/0!	0.00	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!		#DIV/0!		#DIV/0!	
11	13	SJW	No	No	Yes	N/A	N/A	N/A	(55.37)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	#DIV/0!	0.00	#DIV/0!		13
				e					0.00	#DIV/0!	#DIV/0!	0.00	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!		#DIV/0!		#DIV/0!	
	TOTAL PEERS	7	6	10		Mean																																				
			80% Mid Cap		8.86%	36.83%	0.00	Staff Gas Screen																																		
					N/A	36.83%	0.00	Staff Gas and Water Sensitivity Screen																																		
					8.87%	36.60%	0.00	Company Peer Screen																																		

Staff will update Water Sensitivity in Staff Rebuttal Testimony

Average B.O.Y. & E.O.Y. Cash Flows — Model Y — EPS Growth

#	Abbreviated Utility	UG 490 Company	UG 490 Staff	UG 490 Staff Sensitivity	Average IRR	Terminal Value as % of NPV_{DIV}	Average 2023 - 2027 Dividend Growth Rates EOY	BOY	Average	#	
1	1	Atmos	Yes	Yes	Yes	8.3%	41.9%	7.2%	7.5%	7.4%	1	1
2	3	New Jersey	Yes	No	No	8.8%	36.0%	3.8%	3.8%	3.8%	3	2
3	4	NiSource	Yes	Yes	Yes	8.4%	36.7%	3.1%	2.8%	3.0%	4	3
4	5	NW Natural	Yes	Yes	Yes	8.9%	27.7%	0.4%	0.4%	0.4%	5	4
5	6	ONE Gas	Yes	Yes	Yes	8.3%	37.0%	1.9%	2.2%	2.1%	6	5
6	8	Southwest Gas	Yes	Yes	Yes	9.0%	55.9%	1.2%	1.2%	1.2%	8	6
7	9	Spire	Yes	Yes	Yes	9.9%	25.8%	4.5%	4.8%	4.6%	9	7
8	10	American Water	No	No	Yes	N/A	N/A	-100.0%	#DIV/0!	#DIV/0!	10	8
9	11	California Water	No	No	Yes	N/A	N/A	-100.0%	#DIV/0!	#DIV/0!	11	9
10	12	Middlesex Water	No	No	Yes	N/A	N/A	-100.0%	#DIV/0!	#DIV/0!	12	10
11	13	SJW	No	No	Yes	N/A	N/A	-100.0%	#DIV/0!	#DIV/0!	13	11
	TOTAL PEERS	7	6	10		Mean						
			80% Mid Cap		8.79%	37.50%	3.09%	Staff Gas Screen				
					N/A	37.50%	#DIV/0!	Staff Gas and Water Sensitivity Screen				
					8.79%	37.29%	3.19%	Company Peer Screen				

Staff will update Water Sensitivity in Staff Rebuttal Testimony

CASE: UG 490
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 103

ROE – Three-Stage DCF: Summary and Recommendation

April 18, 2024

UG 490 Staff ROE Summary

Stage 3 – Long-Term Annual Dividend and EPS Growth Rates						
Component	Real Rate	TIPS Inflation Forecast	20-Yr Nominal Rate	Weight	Weighted Rate	
Energy Information Administration (EIA)	2.24%	2.39%	4.69%	20.0%	0.94%	
Organization for Economic Co-operation and Development (OECD)ggridlines	1.81%	2.39%	4.24%	20.0%	0.85%	
Social Security Administration (SSA)	1.95%	2.39%	4.39%	20.0%	0.88%	
Congressional Budget Office (CBO)	2.02%	2.39%	4.46%	20.0%	0.89%	
BEA Nominal Historical,1980 Q1–2023 Q4	2.65%	2.39%	5.10%	20.0%	1.02%	
Composite				100%	4.58%	Composite
Congressional Budget Office Long-Term 20-Year Budget Outlook			3.80%	100.0%	4.46%	CBO
BEA Nominal Historical,1980 Q1–2023 Q4	2.65%	2.39%	5.10%	100.0%	5.10%	Historical

Model X: 3 Stage DCF - Dividend Growth with Terminal Value as Perpetuity							
	X	CBO	4.46%	Composite	4.58%	Historical	5.10%
1	Staff Gas Screen	8.35%		8.44%		8.83%	
2	Company Peer Screen	8.37%		8.46%		8.85%	

Hamada to Right

Model X: 3 Stage DCF - Dividend Growth with Terminal Value as Perpetuity (Hamada Adjusted)							
	X	CBO	4.46%	Composite	4.58%	Historical	5.10%
1	Staff Gas Screen	8.23%		8.32%		8.71%	
2	Company Peer Screen	8.20%		8.29%		8.68%	

Model Y: 3 Stage DCF - Dividend Growth with Terminal Value as Sales based upon EPS Growth and Terminal Stock Sale							
	Y	CBO	4.46%	Composite	4.58%	Historical	5.10%
1	Staff Gas Screen	8.83%		8.79%		9.12%	
2	Company Peer Screen	8.83%		8.79%		9.13%	

Hamada to Right

Model Y: 3 Stage DCF - Dividend & EPS Growth with Terminal Value as Stock Sale (Hamada Adjusted)							
	Y	CBO	4.46%	Composite	4.58%	Historical	5.10%
1	Staff Gas Screen	8.71%		8.67%		9.00%	
2	Company Peer Screen	8.66%		8.62%		8.96%	

Common Stock Flotation Costs Adjustment Shifts Range of Reasonable ROE's Upward by : 12.5 bps

Range of Modeled Results 8.84% to 9.26% ROE

Best Fit Range of Reasonable ROEs 8.9% to 9.3% ROE

Midpoint 9.1% ROE

CAPM points toward middle to upper end of Staff's 3 Stage DCF Modeling results.
Gordon Growth Model points toward lower end of Staff's 3 Stage DCF Modeling results.

CASE: UG 490
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 104

ROE:
Capital Asset Pricing Model (CAPM)

April 18, 2024

NWN UG 490 GRC **Capital Asset Pricing Model (CAPM)** **Staff/104 Muldoon/1**

NWN	4.42%
Opening	13.31%
Testimony	8.89%
Staff	4.555%
	9.90%
	5.35%

Rf Rate as shown in Exhibit NWN/400 Coyne-Nelson/13 @31
NWN Mkt Return
NWN Mkt Risk Premium (MRP) as shown in Exhibit NWN/400 Coyne-Nelson/13 @30
R_f as April 5, 2024 30 Yr UST Yields WSJ: Bonds & Rates (wsj.com)
S&P 500 Market Return 1993 thru 2023
Staff Mkt Risk Premium MRP)

$R_{CNG} = R_f + Beta * MRP$

	Screen #	Abbreviated Utility	UG 490 NWN	UG 490 Staff	UG 490 Staff Sensitivity	Ticker	VL Q1 2024 Beta	ROE w VL Beta CAPM	Screen #	
1	1	Atmos	Yes	Yes	Yes	ATO	0.85	9.10%	1	1
2	3	New Jersey	Yes	No	No	NJR	0.95	9.63%	3	2
3	4	NiSource	Yes	Yes	Yes	NI	0.90	9.37%	4	3
4	5	NW Natural	Yes	Yes	Yes	NWN	0.85	9.10%	5	4
5	6	ONE Gas	Yes	Yes	Yes	OGS	0.85	9.10%	6	5
6	8	Southwest Ga	Yes	Yes	Yes	SWX	0.90	9.37%	8	6
7	9	Spire	Yes	Yes	Yes	SR	0.85	9.10%	9	7
8	10	American Wa	No	No	Yes	AWK	0.95	9.63%	10	8
9	11	California Wa	No	No	Yes	CWT	0.75	8.56%	11	9
10	12	Middlesex Wa	No	No	Yes	MSEX	0.75	8.56%	12	10
11	13	SJW	No	No	Yes	SJW	0.85	9.10%	13	11
		No. of Peers:	7	6	10			VL Betas		
						Company Screen	Mean	9.3%	ROE	
					Staff Gas and Water Sensitivity Screen		Mean	9.1%	ROE	
						Staff Screen	Mean	9.2%	ROE	

CAPM points toward middle to upper end of Staff's 3 Stage DCF Modeling results.

CASE: UG 490
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 105

ROE:
Gordon Growth – Single Stage DCF

April 18, 2024

NWN UG 490 GRC | **Gordon Growth Single Stage DCF Model** | **Staff/105 Muldoon/1**

Staff's Representative Single Stage (Gordon Growth) Discounted Cash Flow (DCF) Model

Presumes the Peer Utility will pay its divident as a fixed multiple of growth into the future as it is now.

The results would be true only if the utility stock's dividends were to grow at a constant rate forever.

Value of Stock (P_0) = D_1 / (k- g) — Stock Price Now = Next Year's Dividend / (Required Stock Return - Growth in Dividends)

k = (D_1 / P_0) + g — Required Rate of Return on Utility Equity = (Next Year's VL Dividend / Recent Stock Price) - Perpetual Growth

	1	2	3	4	5	6	7	8	9	11 = 9 + 10	13	14	15
	Screen #	Abbreviated Utility	UG 490 NWN	UG 490 Staff	UG 490 Staff Sensitivity	Ticker	Recent Stock $ Price	Current Dividend Yield	Next VL Annual Dividend	Anticipated Dividend Yield	VL Dividend Growth	Investor Required ROE	Screen #	
1	1	Atmos	Yes	Yes	Yes	ATO	116.00	2.6%	3.22	2.8%	7.3%	10.1%	1	1
2	3	New Jersey	Yes	No	No	NJR	42.43	3.7%	1.68	4.0%	5.0%	8.9%	3	2
3	4	NiSource	Yes	Yes	Yes	NI	26.97	3.7%	1.06	3.9%	4.2%	8.1%	4	3
4	5	NW Natural	Yes	Yes	Yes	NWN	33.46	5.8%	1.95	5.8%	0.4%	6.2%	5	4
5	6	ONE Gas	Yes	Yes	Yes	OGS	62.62	4.2%	2.64	4.2%	2.4%	6.7%	6	5
6	8	Southwest Gas	Yes	Yes	Yes	SWX	72.94	3.4%	2.48	3.4%	1.1%	4.5%	8	6
7	9	Spire	Yes	Yes	Yes	SR	60.01	4.8%	3.02	5.0%	4.7%	9.7%	9	7
8	10	American Water	No	No	Yes	AWK	119.76	2.3%	3.00	2.5%	-100.0%	-97.5%	10	8
9	11	California Water	No	No	Yes	CWT	46.04	2.3%	1.12	2.4%	-100.0%	-97.6%	11	9
10	12	Middlesex Water	No	No	Yes	MSEX	50.55	2.5%	1.32	2.6%	-100.0%	-97.4%	12	10
11	13	SJW	No	No	Yes	SJW	55.37	2.7%	1.60	2.9%	-100.0%	-97.1%	13	11
		No. of Peers:	**7**	**6**	**10**									

	Mean	
Company Screen	7.7%	**ROE**
Staff Gas and Water Sensitivity Screen	N/A	**ROE**
Staff Screen	**7.5%**	**ROE**

Gordon Growth Model points toward lower end of Staff's 3 Stage DCF Modeling results.

CASE: UG 490
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
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OREGON

STAFF EXHIBIT 106

ROE: BEA Historical
GDP Growth

April 18, 2024

Bureau of Economic Analysis (BEA) — Staff Accessed February 20, 2024

Current-Dollar and "Real" Gross Domestic Product (GDP)

Annual https://fred.stlouisfed.org/series/GDPA **Quarterly** https://fred.stlouisfed.org/series/GDP https://fred.stlouisfed.org/series/GDP (

https://fred.stlouisfed.org/series/GDPCA (Seasonally adjusted annual rates)

1980 through 2023 Q4

Yr	GDP in billions of current dollars	GDP in billions of chained 2017 dollars
1947	249.616	2184.614
1948	274.468	2274.627
1949	272.475	2261.928
1950	299.827	2458.532
1951	346.914	2656.32
1952	367.341	2764.803
1953	389.218	2894.411
1954	390.549	2877.708
1955	425.478	3083.026
1956	449.353	3148.765
1957	474.039	3215.065
1958	481.229	3191.216
1959	521.654	3412.421
1960	542.382	3500.272
1961	562.209	3590.066
1962	603.922	3810.124
1963	637.45	3976.142
1964	684.46	4205.277
1965	742.289	4478.555
1966	813.414	4773.931
1967	859.959	4904.864
1968	940.651	5145.914
1969	1017.615	5306.594
1970	1073.303	5316.391
1971	1164.85	5491.445
1972	1279.11	5780.048
1973	1425.376	6106.371
1974	1545.243	6073.363
1975	1684.904	6060.875
1976	1873.412	6387.437
1977	2081.826	6682.804
1978	2351.599	7052.711
1979	2627.333	7275.999
1980	2857.307	7257.316
1981	3207.041	7441.485
1982	3343.789	7307.314
1983	3634.038	7642.266
1984	4037.613	8195.295
1985	4338.979	8537.004
1986	4579.631	8832.611
1987	4855.215	9137.745
1988	5236.438	9519.427
1989	5641.58	9869.003
1990	5963.144	10055.129
1991	6158.129	10044.238
1992	6520.327	10398.046
1993	6858.559	10684.179
1994	7287.236	11114.647
1995	7639.749	11413.012
1996	8073.122	11843.599
1997	8577.552	12370.299
1998	9062.817	12924.876
1999	9631.172	13543.774
2000	10250.952	14096.033
2001	10581.929	14230.726
2002	10929.108	14472.712
2003	11456.45	14877.312
2004	12217.196	15449.757
2005	13039.197	15987.957
2006	13815.583	16433.148
2007	14474.228	16762.445
2008	14769.862	16781.485
2009	14478.067	16349.11
2010	15048.97	16789.75
2011	15599.731	17052.41
2012	16253.97	17442.759
2013	16880.683	17812.167
2014	17608.138	18261.714
2015	18295.019	18799.622
2016	18804.913	19141.672
2017	19612.102	19612.102
2018	20656.516	20193.896
2019	21521.395	20692.087
2020	21322.95	20234.074
2021	23594.031	21407.692
2022	25744.108	21822.037
2023	27356.393	22375.307

Quarter	GDP in billions of current dollars	GDP in billions of chained 2017 dollars	Qtr#
1947Q1	243.164	2182.681	1
1947Q2	245.968	2176.892	2
1947Q3	249.585	2172.432	3
1947Q4	259.745	2206.452	4
1948Q1	265.742	2239.682	5
1948Q2	272.567	2276.690	6
1948Q3	279.196	2289.770	7
1948Q4	280.366	2292.364	8
1949Q1	275.034	2260.807	9
1949Q2	271.351	2253.128	10
1949Q3	272.889	2276.424	11
1949Q4	270.627	2257.352	12
1950Q1	280.828	2346.104	13
1950Q2	290.383	2417.682	14
1950Q3	308.153	2511.127	15
1950Q4	319.945	2559.214	16
1951Q1	336.000	2593.967	17
1951Q2	344.090	2638.898	18
1951Q3	351.385	2693.259	19
1951Q4	356.178	2699.156	20
1952Q1	359.820	2727.554	21
1952Q2	361.030	2733.800	22
1952Q3	367.701	2753.517	23
1952Q4	380.812	2843.941	24
1953Q1	387.980	2896.811	25
1953Q2	391.749	2919.206	26
1953Q3	391.171	2902.785	27
1953Q4	385.970	2858.845	28
1954Q1	385.345	2845.192	29
1954Q2	386.121	2848.305	30
1954Q3	390.996	2880.482	31
1954Q4	399.734	2936.852	32
1955Q1	413.073	3020.746	33
1955Q2	421.532	3069.910	34
1955Q3	430.221	3111.375	35
1955Q4	437.092	3130.068	36
1956Q1	439.746	3117.922	37
1956Q2	446.010	3143.694	38
1956Q3	451.191	3140.874	39
1956Q4	460.463	3192.570	40
1957Q1	469.779	3213.011	41
1957Q2	472.025	3205.970	42
1957Q3	479.490	3237.386	43
1957Q4	474.864	3203.894	44
1958Q1	467.540	3120.724	45
1958Q2	471.978	3141.224	46
1958Q3	485.841	3213.884	47
1958Q4	499.555	3289.032	48
1959Q1	510.330	3352.129	49
1959Q2	522.653	3427.667	50
1959Q3	525.034	3430.057	51
1959Q4	528.600	3439.832	52
1960Q1	542.648	3517.181	53
1960Q2	541.080	3498.246	54
1960Q3	545.604	3515.385	55
1960Q4	540.197	3470.278	56
1961Q1	545.018	3493.703	57
1961Q2	555.545	3553.021	58
1961Q3	567.664	3621.252	59
1961Q4	580.612	3692.289	60
1962Q1	594.013	3758.147	61
1962Q2	600.366	3792.149	62
1962Q3	609.027	3838.776	63
1962Q4	612.280	3851.421	64
1963Q1	621.672	3893.482	65
1963Q2	629.752	3937.183	66
1963Q3	644.444	4023.755	67
1963Q4	653.938	4050.147	68
1964Q1	669.822	4135.553	69
1964Q2	678.674	4180.592	70
1964Q3	692.031	4245.918	71
1964Q4	697.319	4259.046	72
1965Q1	717.790	4362.111	73
1965Q2	730.191	4417.225	74
1965Q3	749.323	4515.427	75
1965Q4	771.857	4619.458	76
1966Q1	795.734	4731.888	77
1966Q2	804.981	4748.046	78
1966Q3	819.638	4788.254	79
1966Q4	833.302	4827.537	80
1967Q1	844.170	4870.299	81
1967Q2	848.983	4873.287	82
1967Q3	865.233	4919.392	83
1967Q4	881.439	4956.477	84
1968Q1	909.387	5057.553	85
1968Q2	934.344	5142.033	86
1968Q3	950.825	5181.859	87
1968Q4	968.030	5202.212	88
1969Q1	993.337	5283.597	89
1969Q2	1009.020	5299.625	90
1969Q3	1029.956	5334.600	91
1969Q4	1038.147	5308.556	92
1970Q1	1051.200	5300.652	93
1970Q2	1067.375	5308.164	94
1970Q3	1086.059	5357.077	95
1970Q4	1088.608	5299.672	96
1971Q1	1135.156	5443.619	97
1971Q2	1156.271	5473.059	98
1971Q3	1177.675	5518.072	99
1971Q4	1190.297	5531.032	100
1972Q1	1230.609	5632.649	101
1972Q2	1266.369	5760.470	102
1972Q3	1290.566	5814.854	103
1972Q4	1328.904	5912.220	104
1973Q1	1377.490	6058.544	105
1973Q2	1413.887	6124.506	106
1973Q3	1433.838	6092.301	107
1973Q4	1476.289	6150.131	108
1974Q1	1491.209	6097.258	109
1974Q2	1530.056	6111.751	110
1974Q3	1560.026	6053.978	111
1974Q4	1599.679	6030.464	112
1975Q1	1616.116	5957.035	113
1975Q2	1651.853	5999.610	114
1975Q3	1709.820	6102.326	115
1975Q4	1761.831	6184.530	116
1976Q1	1820.487	6323.649	117
1976Q2	1852.332	6370.025	118
1976Q3	1886.558	6404.895	119
1976Q4	1934.273	6451.177	120
1977Q1	1988.648	6527.703	121
1977Q2	2055.909	6654.466	122
1977Q3	2118.473	6774.457	123
1977Q4	2164.270	6774.592	124
1978Q1	2202.760	6796.260	125
1978Q2	2331.633	7058.920	126
1978Q3	2395.053	7129.915	127
1978Q4	2476.949	7225.750	128
1979Q1	2526.610	7238.727	129
1979Q2	2591.247	7246.454	130
1979Q3	2667.565	7300.281	131
1979Q4	2723.883	7318.535	132
1980Q1	2769.842	7341.587	133
1980Q2	2797.352	7190.289	134
1980Q3	2856.483	7181.743	135
1980Q4	2985.557	7315.677	136
1981Q1	3124.206	7459.022	137
1981Q2	3162.532	7403.745	138
1981Q3	3260.609	7492.405	139
1981Q4	3280.818	7410.768	140
1982Q1	3274.302	7295.631	141
1982Q2	3331.972	7328.912	142
1982Q3	3366.322	7300.896	143
1982Q4	3402.561	7303.817	144
1983Q1	3473.413	7400.066	145
1983Q2	3578.848	7568.456	146
1983Q3	3689.179	7719.746	147
1983Q4	3794.706	7880.794	148

Average	Ln(Real GDP)	
1	8.901	1980
2	8.880	
3	8.879	
4	8.898	
5	8.917	1981
6	8.910	
7	8.922	
8	8.911	
9	8.895	1982
10	8.900	
11	8.896	
12	8.896	
13	8.909	1983
14	8.932	
15	8.952	
16	8.972	
17	8.992	1984
18	9.009	
19	9.018	
20	9.026	
21	9.036	1985
22	9.045	
23	9.060	
24	9.067	
25	9.077	1986
26	9.081	
27	9.091	
28	9.096	
29	9.103	1987
30	9.114	
31	9.123	
32	9.140	
33	9.145	1988
34	9.158	
35	9.164	
36	9.177	
37	9.187	1989
38	9.195	
39	9.202	
40	9.204	
41	9.215	1990
42	9.219	
43	9.219	
44	9.210	
45	9.206	1991
46	9.213	
47	9.218	
48	9.222	
49	9.234	1992
50	9.244	
51	9.254	
52	9.265	
53	9.266	1993
54	9.272	
55	9.277	
56	9.290	
57	9.300	1994
58	9.314	
59	9.319	
60	9.331	
61	9.334	1995
62	9.337	
63	9.346	
64	9.353	
65	9.360	1996
66	9.377	
67	9.385	
68	9.396	
69	9.402	1997
70	9.419	
71	9.431	
72	9.440	
73	9.450	1998
74	9.459	
75	9.471	
76	9.487	
77	9.497	1999
78	9.505	
79	9.518	
80	9.534	
81	9.538	2000
82	9.556	
83	9.557	
84	9.563	
85	9.560	2001
86	9.566	
87	9.562	
88	9.565	
89	9.573	2002
90	9.579	
91	9.583	
92	9.584	
93	9.590	2003
94	9.599	
95	9.615	
96	9.627	
97	9.632	2004
98	9.640	
99	9.649	
100	9.660	
101	9.671	2005
102	9.676	
103	9.683	
104	9.689	
105	9.702	2006
106	9.705	
107	9.706	
108	9.715	
109	9.718	2007
110	9.724	
111	9.730	
112	9.736	
113	9.732	2008
114	9.738	
115	9.732	
116	9.710	
117	9.699	2009
118	9.697	
119	9.701	
120	9.711	
121	9.716	2010
122	9.726	
123	9.733	
124	9.739	
125	9.736	2011
126	9.743	
127	9.743	
128	9.754	
129	9.762	2012
130	9.767	
131	9.768	
132	9.769	
133	9.779	2013
134	9.782	
135	9.790	
136	9.799	
137	9.796	2014
138	9.808	
139	9.820	
140	9.826	
141	9.834	2015
142	9.841	
143	9.845	
144	9.847	
145	9.852	2016
146	9.855	
147	9.863	
148	9.868	

Long Run Historical GDP Growth Rate

Annualized Real LN GPD Q

2.65%

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.989672527
R Square	0.979451711
Adjusted R Square	0.979333617
Standard Error	0.048579271
Observations	176

ANOVA

	df	SS	MS	F	Significance F
Regression	1	19.57305439	19.57305439	8293.858359	9.9307E-149
Residual	174	0.410630531	0.002359946		
Total	175	19.98368493			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
Intercept	8.926549282	0.007354921	1213.683982	0	8.912032939	8.941065626	8.912032939	8.941065626
Average	0.006563839	7.20742E-05	91.07062292	9.9307E-149	0.006421587	0.006706091	0.006421587	0.006706091

Note **July 31, 2013, 14th Comprehensive Significant Revision:**
BEA revised its tables back to 1929 in to order to count:
1 Artistic Works
2 Research and Development
as Capital Investments that Depreciate Over Time rather than one time expenditures

From an Economy based on (Industry and Manufacturing) to one based on (Knowledge and Information)

1984Q1	3908.054	8034.847	149	149	9.873	2017
1984Q2	4009.601	8173.670	150	150	9.879	
1984Q3	4084.250	8252.465	151	151	9.886	
1984Q4	4146.551	8320.199	152	152	9.898	
1985Q1	4230.168	8400.820	153	153	9.906	2018
1985Q2	4294.887	8474.787	154	154	9.911	
1985Q3	4386.773	8604.220	155	155	9.917	
1985Q4	4444.094	8668.188	156	156	9.919	
1986Q1	4507.894	8749.127	157	157	9.924	2019
1986Q2	4545.340	8788.524	158	158	9.932	
1986Q3	4607.669	8872.601	159	159	9.944	
1986Q4	4657.627	8920.193	160	160	9.950	
1987Q1	4722.156	8986.367	161	161	9.936	2020
1987Q2	4806.160	9083.256	162	162	9.854	
1987Q3	4884.555	9162.024	163	163	9.929	
1987Q4	5007.994	9319.332	164	164	9.939	
1988Q1	5073.372	9367.502	165	165	9.952	2021
1988Q2	5190.036	9490.594	166	166	9.967	
1988Q3	5282.835	9546.206	167	167	9.975	
1988Q4	5399.509	9673.405	168	168	9.992	
1989Q1	5511.253	9771.725	169	169	9.987	2022
1989Q2	5612.463	9846.293	170	170	9.985	
1989Q3	5695.365	9919.228	171	171	9.992	
1989Q4	5747.237	9938.767	172	172	9.998	
1990Q1	5872.701	10047.386	173	173	10.004	2023
1990Q2	5960.028	10083.855	174	174	10.009	
1990Q3	6015.116	10090.569	175	175	10.021	
1990Q4	6004.733	9998.704	176	176	10.029	
1991Q1	6035.178	9951.916	177			
1991Q2	6126.862	10029.510	178			
1991Q3	6205.937	10080.195	179			
1991Q4	6264.540	10115.329	180			
1992Q1	6363.102	10236.435	181			
1992Q2	6470.763	10347.429	182			
1992Q3	6566.641	10449.673	183			
1992Q4	6680.803	10558.648	184			
1993Q1	6729.459	10576.275	185			
1993Q2	6808.939	10637.847	186			
1993Q3	6882.098	10688.606	187			
1993Q4	7013.738	10833.987	188			
1994Q1	7115.652	10939.116	189			
1994Q2	7246.931	11087.361	190			
1994Q3	7331.075	11152.176	191			
1994Q4	7455.288	11279.932	192			
1995Q1	7522.289	11319.951	193			
1995Q2	7580.997	11353.721	194			
1995Q3	7683.125	11450.310	195			
1995Q4	7772.586	11528.067	196			
1996Q1	7868.468	11614.418	197			
1996Q2	8032.840	11808.140	198			
1996Q3	8131.408	11914.063	199			
1996Q4	8259.771	12037.775	200			
1997Q1	8362.655	12118.472	201			
1997Q2	8518.825	12317.221	202			
1997Q3	8662.823	12471.010	203			
1997Q4	8765.907	12577.495	204			
1998Q1	8866.480	12703.742	205			
1998Q2	8969.699	12821.339	206			
1998Q3	9121.097	12982.752	207			
1998Q4	9293.991	13191.670	208			
1999Q1	9411.682	13315.597	209			
1999Q2	9526.210	13426.748	210			
1999Q3	9686.626	13604.771	211			
1999Q4	9900.169	13827.980	212			
2000Q1	10002.179	13878.147	213			
2000Q2	10247.720	14130.908	214			
2000Q3	10318.165	14145.312	215			
2000Q4	10435.744	14229.765	216			
2001Q1	10470.231	14183.120	217			
2001Q2	10599.000	14271.694	218			
2001Q3	10598.020	14214.516	219			
2001Q4	10660.465	14253.574	220			
2002Q1	10783.500	14372.785	221			
2002Q2	10887.460	14460.848	222			
2002Q3	10984.040	14519.633	223			
2002Q4	11061.433	14537.580	224			
2003Q1	11174.129	14614.141	225			
2003Q2	11312.766	14743.667	226			
2003Q3	11566.669	14988.782	227			
2003Q4	11772.234	15162.760	228			
2004Q1	11923.447	15248.680	229			
2004Q2	12112.815	15366.850	230			
2004Q3	12305.307	15512.619	231			
2004Q4	12527.214	15670.880	232			
2005Q1	12767.286	15844.727	233			
2005Q2	12922.656	15922.782	234			
2005Q3	13142.642	16047.587	235			
2005Q4	13324.204	16136.734	236			
2006Q1	13599.160	16353.835	237			
2006Q2	13753.424	16396.151	238			
2006Q3	13870.188	16420.738	239			
2006Q4	14039.560	16561.866	240			
2007Q1	14215.651	16611.690	241			
2007Q2	14402.082	16713.314	242			
2007Q3	14564.117	16809.587	243			
2007Q4	14715.058	16915.191	244			
2008Q1	14706.538	16843.003	245			
2008Q2	14865.701	16943.291	246			
2008Q3	14898.999	16854.295	247			
2008Q4	14608.208	16485.350	248			
2009Q1	14430.901	16298.262	249			
2009Q2	14381.236	16269.145	250			
2009Q3	14448.882	16326.281	251			
2009Q4	14651.249	16502.754	252			
2010Q1	14764.610	16582.710	253			
2010Q2	14980.193	16743.162	254			
2010Q3	15141.607	16872.266	255			
2010Q4	15309.474	16960.864	256			
2011Q1	15351.448	16920.632	257			
2011Q2	15557.539	17035.114	258			
2011Q3	15647.680	17031.313	259			
2011Q4	15842.259	17222.583	260			
2012Q1	16068.805	17367.010	261			
2012Q2	16207.115	17444.525	262			
2012Q3	16319.541	17469.650	263			
2012Q4	16420.419	17489.852	264			
2013Q1	16648.189	17662.400	265			
2013Q2	16728.687	17709.671	266			
2013Q3	16953.838	17860.450	267			
2013Q4	17192.019	18016.147	268			
2014Q1	17197.738	17953.974	269			
2014Q2	17518.508	18185.911	270			
2014Q3	17804.228	18406.941	271			
2014Q4	17912.079	18500.031	272			
2015Q1	18063.529	18666.621	273			
2015Q2	18279.784	18782.243	274			
2015Q3	18401.626	18857.418	275			
2015Q4	18435.137	18892.206	276			
2016Q1	18525.933	19001.690	277			
2016Q2	18711.702	19062.709	278			
2016Q3	18892.639	19197.938	279			
2016Q4	19089.379	19304.352	280			
2017Q1	19280.084	19398.343	281			
2017Q2	19438.643	19506.949	282			
2017Q3	19692.595	19660.766	283			
2017Q4	20037.088	19882.352	284			
2018Q1	20328.553	20044.077	285			
2018Q2	20580.912	20150.476	286			
2018Q3	20798.730	20276.154	287			
2018Q4	20917.867	20304.874	288			
2019Q1	21104.133	20415.150	289			
2019Q2	21384.775	20584.528	290			
2019Q3	21694.282	20817.581	291			
2019Q4	21902.390	20951.088	292			
2020Q1	21706.513	20665.553	293			
2020Q2	19913.143	19034.830	294			
2020Q3	21647.64	20511.785	295			
2020Q4	22024.502	20724.128	296			
2021Q1	22600.185	20990.541	297			
2021Q2	23292.362	21309.544	298			
2021Q3	23828.973	21483.083	299			
2021Q4	24654.603	21847.602	300			

CASE: UG 490
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 107

ROE: TIPS Implied Inflation

April 18, 2024

NWN UG 490 GRC | **TIPS Implied Forward Curve** | **Staff/107 Muldoon/1**

2023 through 2053 TIPs-Implied Average Annual Inflation Rate: **2.39%**

Implied Market-based Inflationary Expectations						
Qtr	5-Yr	7-Yr	10-Yr	20-Yr	30-Yr	
2023-Q4	2.2%	2.3%	2.3%	2.6%	2.4%	IPC UE 426

Source: Federal Reserve Statistical Release H.15
See H15 Qtrly Avg for data feed

Yr. End Mo.-Yr.	Years	Individually Implied Price Levels					Implied Forward Curve/Price Level					Implied Price Level	Check
		5-Yr	7-Yr	10-Yr	20-Yr	30-Yr	5-Yr	7-Yr	10-Yr	20-Yr	30-Yr		
Dec-23	0	100.00	100.00	100.00	100.00	100.00	100.00					100.00	
Dec-24	1	102.23	102.30	102.29	102.57	102.35	102.23					102.23	
Dec-25	2	104.50	104.65	104.63	105.21	104.76	104.50					104.50	
Dec-26	3	106.83	107.05	107.03	107.91	107.23	106.83					106.83	
Dec-27	4	109.21	109.51	109.48	110.68	109.75	109.21					109.21	
Dec-28	5	111.64	112.02	111.99	113.53	112.33	111.64					111.64	
Dec-29	6		114.60	114.55	116.45	114.98		114.40				114.40	
Dec-30	7		117.23	117.17	119.44	117.68		117.23				117.23	
Dec-31	8			119.86	122.51	120.45			119.89			119.89	
Dec-32	9			122.60	125.66	123.29			122.62			122.62	
Dec-33	10			125.41	128.89	126.19			125.41			125.41	
Dec-34	11				132.20	129.16				128.99		128.99	128.40
Dec-35	12				135.60	132.20				132.66		132.66	131.46
Dec-36	13				139.08	135.31				136.44		136.44	134.60
Dec-37	14				142.65	138.49				140.33		140.33	137.81
Dec-38	15				146.32	141.75				144.33		144.33	141.10
Dec-39	16				150.08	145.09				148.45		148.45	144.46
Dec-40	17				153.94	148.50				152.68		152.68	147.91
Dec-41	18				157.89	152.00				157.03		157.03	151.43
Dec-42	19				161.95	155.57				161.51		161.51	155.05
Dec-43	20				166.11	159.24				166.11		166.11	158.74
Dec-44	21					162.98					169.31	169.31	162.53
Dec-45	22					166.82					172.56	172.56	166.41
Dec-46	23					170.74					175.87	175.87	170.37
Dec-47	24					174.76					179.25	179.25	174.44
Dec-48	25					178.88					182.70	182.70	178.60
Dec-49	26					183.08					186.21	186.21	182.86
Dec-50	27					187.39					189.79	189.79	187.22
Dec-51	28					191.80					193.43	193.43	191.68
Dec-52	29					196.32					197.15	197.15	196.26
Dec-53	30					200.94					200.94	200.94	200.94

Average Quarterly Values for FRB H15 Data

See FRB H.15 Tab for Data Feed Sources.

Staff TIPS Analysis **Quarterly Aggregation**

Average Monthly Inflation Indexed Rates by Quarter					
Qtr	TIPS-05m	TIPS-07m	TIPS-10m	TIPS-20m	TIPS-30m
2003-Q1	1.33	1.81	2.07		
2003-Q2	1.15	1.61	1.94		
2003-Q3	1.36	1.84	2.21		
2003-Q4	1.24	1.65	2.01		
2004-Q1	0.82	1.26	1.71		
2004-Q2	1.26	1.69	2.05		
2004-Q3	1.17	1.55	1.89	2.28	
2004-Q4	0.93	1.30	1.69	2.08	
2005-Q1	1.17	1.41	1.71	1.93	
2005-Q2	1.30	1.44	1.68	1.83	
2005-Q3	1.59	1.70	1.82	1.98	
2005-Q4	1.92	1.98	2.04	2.13	
2006-Q1	2.00	2.05	2.09	2.08	
2006-Q2	2.34	2.39	2.46	2.48	
2006-Q3	2.37	2.37	2.37	2.38	
2006-Q4	2.40	2.36	2.32	2.29	
2007-Q1	2.28	2.33	2.33	2.36	
2007-Q2	2.35	2.40	2.44	2.49	
2007-Q3	2.38	2.44	2.45	2.46	
2007-Q4	1.54	1.81	1.92	2.11	
2008-Q1	0.58	1.02	1.32	1.81	
2008-Q2	0.79	1.17	1.48	2.03	
2008-Q3	1.18	1.47	1.70	2.16	
2008-Q4	2.73	2.92	2.60	2.73	
2009-Q1	1.37	1.54	1.79	2.34	
2009-Q2	1.12	1.37	1.72	2.31	
2009-Q3	1.17	1.41	1.74	2.22	
2009-Q4	0.58	0.94	1.37	1.98	
2010-Q1	0.47	0.94	1.43	2.00	2.16
2010-Q2	0.46	0.91	1.36	1.77	1.88
2010-Q3	0.20	0.57	1.06	1.68	1.76
2010-Q4	-0.11	0.28	0.75	1.48	1.65
2011-Q1	0.07	0.67	1.09	1.71	2.00
2011-Q2	-0.29	0.33	0.80	1.49	1.78
2011-Q3	-0.65	-0.22	0.28	0.95	1.25
2011-Q4	-0.75	-0.39	0.05	0.61	0.85
2012-Q1	-1.02	-0.60	-0.17	0.51	0.78
2012-Q2	**-1.08**	**-0.75**	**-0.35**	**0.35**	**0.66**
2012-Q3	-1.27	-1.01	-0.63	0.02	0.43
2012-Q4	**-1.42**	**-1.15**	**-0.76**	**-0.02**	**0.36**
2013-Q1	-1.40	-0.98	-0.59	0.19	0.56
2013-Q2	**-1.04**	**-0.62**	**-0.25**	**0.47**	**0.80**
2013-Q3	-0.32	0.17	0.56	1.16	1.43
2013-Q4	**-0.29**	**0.25**	**0.57**	**1.19**	**1.50**
2014-Q1	-0.16	0.37	0.58	1.11	1.39
2014-Q2	**-0.25**	**0.27**	**0.43**	**0.88**	**1.14**
2014-Q3	-0.13	0.24	0.32	0.72	0.98
2014-Q4	**0.19**	**0.39**	**0.45**	**0.75**	**0.95**
2015-Q1	0.11	0.23	0.27	0.52	0.71
2015-Q2	**-0.10**	**0.22**	**0.30**	**0.67**	**0.91**
2015-Q3	0.26	0.48	0.57	0.92	1.14
2015-Q4	**0.36**	**0.51**	**0.66**	**1.02**	**1.24**
2016-Q1	0.15	0.32	0.49	0.88	1.11
2016-Q2	**-0.24**	**-0.05**	**0.19**	**0.62**	**0.85**
2016-Q3	-0.22	-0.09	0.08	0.44	0.62
2016-Q4	**-0.06**	**0.12**	**0.33**	**0.69**	**0.86**
2017-Q1	0.07	0.33	0.44	0.75	0.95
2017-Q2	**0.10**	**0.30**	**0.44**	**0.76**	**0.94**
2017-Q3	0.17	0.36	0.45	0.75	0.94
2017-Q4	**0.32**	**0.44**	**0.50**	**0.72**	**0.87**
2018-Q1	0.56	0.65	0.68	0.82	0.93
2018-Q2	**0.69**	**0.77**	**0.79**	**0.88**	**0.95**
2018-Q3	0.81	0.81	0.81	0.88	0.93
2018-Q4	**1.06**	**1.06**	**1.06**	**1.15**	**1.23**
2019-Q1	0.73	0.76	0.79	0.96	1.10
2019-Q2	**0.42**	**0.46**	**0.51**	**0.71**	**0.89**
2019-Q3	0.18	0.16	0.15	0.37	0.59
2019-Q4	**0.09**	**0.11**	**0.15**	**0.36**	**0.54**
2020-Q1	-0.14	-0.12	-0.06	0.14	0.29
2020-Q2	**-0.49**	**-0.50**	**-0.48**	**-0.27**	**-0.09**
2020-Q3	-1.19	-1.09	-0.94	-0.58	-0.33
2020-Q4	**-1.32**	**-1.13**	**-0.91**	**-0.50**	**-0.29**
2021-Q1	-1.70	-1.27	-0.86	-0.34	-0.09
2021-Q2	**-1.71**	**-1.18**	**-0.79**	**-0.27**	**-0.03**
2021-Q3	-1.69	-1.31	-1.02	-0.53	-0.30
2021-Q4	**-1.65**	**-1.30**	**-1.00**	**-0.58**	**-0.38**

Average Monthly Nominal UST Rates by Quarter					
Qtr	UST-05m	UST-07m	UST-10m	UST-20m	UST-30m
2003-Q1	2.91	3.46	3.92	4.90	
2003-Q2	2.57	3.13	3.62	4.59	
2003-Q3	3.14	3.72	4.23	5.17	
2003-Q4	3.25	3.78	4.29	5.16	
2004-Q1	2.99	3.52	4.02	4.89	
2004-Q2	3.72	4.18	4.60	5.36	
2004-Q3	3.51	3.92	4.30	5.07	
2004-Q4	3.49	3.85	4.17	4.87	
2005-Q1	3.88	4.09	4.30	4.76	
2005-Q2	3.87	3.99	4.16	4.55	
2005-Q3	4.04	4.11	4.21	4.51	
2005-Q4	4.39	4.42	4.49	4.77	
2006-Q1	4.55	4.55	4.57	4.76	4.64
2006-Q2	4.99	5.02	5.07	5.29	5.14
2006-Q3	4.84	4.85	4.90	5.09	4.99
2006-Q4	4.60	4.60	4.63	4.83	4.74
2007-Q1	4.65	4.65	4.68	4.90	4.80
2007-Q2	4.76	4.79	4.85	5.07	4.99
2007-Q3	4.50	4.60	4.73	5.01	4.94
2007-Q4	3.79	3.98	4.26	4.65	4.61
2008-Q1	2.75	3.15	3.66	4.40	4.41
2008-Q2	3.16	3.46	3.89	4.59	4.58
2008-Q3	3.11	3.44	3.86	4.49	4.45
2008-Q4	2.18	2.63	3.25	3.97	3.68
2009-Q1	1.76	2.23	2.74	3.69	3.45
2009-Q2	2.23	2.88	3.31	4.19	4.17
2009-Q3	2.47	3.12	3.52	4.28	4.32
2009-Q4	2.30	2.98	3.46	4.27	4.33
2010-Q1	2.42	3.16	3.72	4.49	4.62
2010-Q2	2.25	2.93	3.49	4.20	4.37
2010-Q3	1.55	2.19	2.79	3.60	3.85
2010-Q4	1.49	2.18	2.86	3.84	4.16
2011-Q1	2.12	2.83	3.46	4.32	4.56
2011-Q2	1.86	2.55	3.21	4.07	4.34
2011-Q3	1.15	1.78	2.43	3.34	3.70
2011-Q4	0.95	1.50	2.05	2.75	3.04
2012-Q1	0.90	1.44	2.04	2.80	3.14
2012-Q2	**0.79**	**1.24**	**1.82**	**2.55**	**2.94**
2012-Q3	0.67	1.08	1.64	2.37	2.75
2012-Q4	**0.69**	**1.12**	**1.71**	**2.46**	**2.86**
2013-Q1	0.83	1.32	1.95	2.75	3.14
2013-Q2	**0.92**	**1.39**	**2.00**	**2.78**	**3.15**
2013-Q3	1.51	2.12	2.71	3.44	3.72
2013-Q4	**1.44**	**2.12**	**2.75**	**3.50**	**3.79**
2014-Q1	1.60	2.22	2.76	3.42	3.68
2014-Q2	**1.66**	**2.19**	**2.62**	**3.18**	**2.81**
2014-Q3	1.70	2.16	2.50	3.01	3.26
2014-Q4	**1.60**	**2.00**	**2.28**	**2.69**	**2.97**
2015-Q1	1.45	1.77	1.97	2.32	2.55
2015-Q2	**1.52**	**1.91**	**2.17**	**2.62**	**2.89**
2015-Q3	1.55	1.94	2.22	2.65	2.96
2015-Q4	**1.59**	**1.94**	**2.19**	**2.60**	**2.96**
2016-Q1	1.37	1.69	1.92	2.32	2.72
2016-Q2	**1.24**	**1.54**	**1.75**	**2.15**	**2.57**
2016-Q3	1.13	1.40	1.56	1.91	2.28
2016-Q4	**1.61**	**1.93**	**2.13**	**2.52**	**2.82**
2017-Q1	1.94	2.25	2.44	2.78	3.04
2017-Q2	**1.81**	**2.07**	**2.26**	**2.64**	**2.90**
2017-Q3	1.82	2.06	2.24	2.58	2.82
2017-Q4	**2.07**	**2.25**	**2.37**	**2.62**	**2.82**
2018-Q1	2.54	2.69	2.76	2.91	3.03
2018-Q2	**2.77**	**2.87**	**2.92**	**3.00**	**3.08**
2018-Q3	2.81	2.88	2.93	3.00	3.07
2018-Q4	**2.88**	**2.96**	**3.03**	**3.17**	**3.27**
2019-Q1	2.47	2.55	2.65	2.85	3.01
2019-Q2	**2.12**	**2.22**	**2.33**	**2.58**	**2.78**
2019-Q3	1.63	1.71	1.80	2.08	2.28
2019-Q4	**1.62**	**1.72**	**1.79**	**2.10**	**2.26**
2020-Q1	1.16	1.29	1.38	1.71	1.88
2020-Q2	**0.36**	**0.54**	**0.69**	**1.15**	**1.38**
2020-Q3	0.27	0.46	0.65	1.15	1.36
2020-Q4	**0.37**	**0.61**	**0.86**	**1.40**	**1.62**
2021-Q1	0.60	0.98	1.32	1.92	2.07
2021-Q2	**0.84**	**1.27**	**1.59**	**2.17**	**2.26**
2021-Q3	0.80	1.10	1.32	1.86	1.93
2021-Q4	**1.18**	**1.42**	**1.54**	**1.97**	**1.95**

Implied Market-based Inflationary Expectations					
Qtr	5-Yr	7-Yr	10-Yr	20-Yr	30-Yr
2003-Q1	1.58	1.65	1.85		
2003-Q2	1.42	1.52	1.68		
2003-Q3	1.78	1.87	2.03		
2003-Q4	2.01	2.13	2.28		
2004-Q1	2.17	2.26	2.31		
2004-Q2	2.47	2.50	2.55		
2004-Q3	2.34	2.37	2.41	2.79	
2004-Q4	2.56	2.55	2.48	2.79	
2005-Q1	2.72	2.68	2.58	2.83	
2005-Q2	2.57	2.55	2.48	2.72	
2005-Q3	2.44	2.41	2.39	2.52	
2005-Q4	2.47	2.44	2.45	2.64	
2006-Q1	2.55	2.50	2.48	2.69	
2006-Q2	2.65	2.62	2.61	2.80	
2006-Q3	2.47	2.48	2.52	2.71	
2006-Q4	2.20	2.24	2.31	2.54	
2007-Q1	2.36	2.32	2.35	2.54	
2007-Q2	2.41	2.39	2.41	2.58	
2007-Q3	2.13	2.16	2.28	2.55	
2007-Q4	2.24	2.17	2.34	2.54	
2008-Q1	2.17	2.13	2.34	2.59	
2008-Q2	2.37	2.29	2.40	2.56	
2008-Q3	1.93	1.96	2.16	2.33	
2008-Q4	-0.55	-0.29	0.65	1.24	
2009-Q1	0.39	0.69	0.95	1.35	
2009-Q2	1.11	1.51	1.60	1.88	
2009-Q3	1.30	1.72	1.77	2.06	
2009-Q4	1.72	2.04	2.09	2.29	
2010-Q1	1.96	2.22	2.28	2.49	2.47
2010-Q2	1.80	2.03	2.13	2.43	2.49
2010-Q3	1.35	1.63	1.73	1.92	2.09
2010-Q4	1.59	1.90	2.12	2.36	2.51
2011-Q1	2.05	2.16	2.37	2.61	2.56
2011-Q2	2.15	2.22	2.41	2.57	2.56
2011-Q3	1.81	2.00	2.15	2.39	2.45
2011-Q4	1.71	1.89	1.99	2.14	2.19
2012-Q1	1.92	2.04	2.20	2.29	2.36
2012-Q2	**1.86**	**1.99**	**2.17**	**2.21**	**2.28**
2012-Q3	1.94	2.09	2.28	2.35	2.31
2012-Q4	**2.11**	**2.27**	**2.47**	**2.48**	**2.50**
2013-Q1	2.23	2.31	2.54	2.55	2.58
2013-Q2	**1.95**	**2.01**	**2.25**	**2.32**	**2.34**
2013-Q3	1.82	1.95	2.15	2.29	2.29
2013-Q4	**1.73**	**1.86**	**2.17**	**2.31**	**2.29**
2014-Q1	1.77	1.85	2.18	2.30	2.29
2014-Q2	**1.90**	**1.92**	**2.20**	**2.30**	**1.67**
2014-Q3	1.83	1.92	2.18	2.28	2.29
2014-Q4	**1.41**	**1.61**	**1.83**	**1.95**	**2.02**
2015-Q1	1.35	1.54	1.70	1.79	1.85
2015-Q2	**1.63**	**1.69**	**1.86**	**1.95**	**1.97**
2015-Q3	1.29	1.47	1.65	1.73	1.82
2015-Q4	**1.23**	**1.43**	**1.53**	**1.58**	**1.72**
2016-Q1	1.23	1.37	1.43	1.45	1.61
2016-Q2	**1.48**	**1.58**	**1.56**	**1.53**	**1.72**
2016-Q3	1.35	1.49	1.48	1.47	1.66
2016-Q4	**1.67**	**1.80**	**1.80**	**1.83**	**1.96**
2017-Q1	1.87	1.92	2.01	2.03	2.10
2017-Q2	**1.71**	**1.78**	**1.82**	**1.88**	**1.96**
2017-Q3	1.65	1.70	1.79	1.83	1.88
2017-Q4	**1.75**	**1.81**	**1.87**	**1.89**	**1.95**
2018-Q1	1.97	2.04	2.08	2.08	2.11
2018-Q2	**2.07**	**2.11**	**2.13**	**2.12**	**2.14**
2018-Q3	2.01	2.07	2.11	2.11	2.13
2018-Q4	**1.81**	**1.90**	**1.98**	**2.02**	**2.03**
2019-Q1	1.73	1.79	1.86	1.89	1.91
2019-Q2	**1.70**	**1.76**	**1.82**	**1.87**	**1.88**
2019-Q3	1.45	1.55	1.64	1.71	1.69
2019-Q4	**1.53**	**1.61**	**1.64**	**1.74**	**1.72**
2020-Q1	1.30	1.41	1.44	1.58	1.59
2020-Q2	**0.85**	**1.05**	**1.16**	**1.42**	**1.47**
2020-Q3	1.46	1.55	1.59	1.73	1.69
2020-Q4	**1.69**	**1.75**	**1.78**	**1.90**	**1.91**
2021-Q1	2.30	2.25	2.18	2.26	2.16
2021-Q2	**2.55**	**2.45**	**2.39**	**2.44**	**2.29**
2021-Q3	2.49	2.41	2.34	2.39	2.23
2021-Q4	**2.83**	**2.72**	**2.54**	**2.55**	**2.33**

FRB **H.15** Market Yield on U.S. Treasury (UST) Securities at Constant Maturity, Quoted on an Investment Basis in Percent per Year

Staff Accessed , Feb. 15, 2023: http://federalreserve.gov/releases/h15/data.htm

Monthly https://www.federalreserve.gov/datadownload/Choose.aspx?rel=H15

TIPS-05m	5				RIFLGFCY05_XII_N.M
TIPS-07m	7				RIFLGFCY07_XII_N.M
TIPS-10m	10	**Year**	**Inflation Indexed**	**H.15 ID**	RIFLGFCY10_XII_N.M
TIPS-20m	20				RIFLGFCY20_XII_N.M
TIPS-30m	30				RIFLGFCY30_XII_N.M

Month	TIPS-05m	TIPS-07m	TIPS-10m	TIPS-20m	TIPS-30m
2003-01	1.65	2.10	2.29		
2003-02	1.24	1.74	1.99		
2003-03	1.09	1.60	1.94		
2003-04	1.36	1.85	2.18		
2003-05	1.18	1.61	1.91		
2003-06	0.91	1.37	1.72		
2003-07	1.30	1.76	2.11		
2003-08	1.48	1.97	2.32		
2003-09	1.29	1.80	2.19		
2003-10	1.21	1.68	2.08		
2003-11	1.27	1.64	1.96		
2003-12	1.23	1.64	1.98		
2004-01	1.09	1.48	1.89		
2004-02	0.86	1.31	1.76		
2004-03	0.52	0.98	1.47		
2004-04	1.02	1.49	1.90		
2004-05	1.34	1.77	2.09		
2004-06	1.41	1.80	2.15	TIPS-20	
2004-07	1.29	1.68	2.02	2.44	
2004-08	1.12	1.51	1.86	2.23	
2004-09	1.10	1.46	1.80	2.16	
2004-10	0.97	1.35	1.73	2.13	
2004-11	0.90	1.27	1.68	2.09	
2004-12	0.92	1.28	1.67	2.02	
2005-01	1.13	1.40	1.72	1.98	
2005-02	1.08	1.33	1.63	1.85	
2005-03	1.29	1.49	1.79	1.95	
2005-04	1.23	1.42	1.71	1.87	
2005-05	1.28	1.41	1.65	1.82	
2005-06	1.39	1.49	1.67	1.80	
2005-07	1.67	1.75	1.88	2.00	
2005-08	1.71	1.79	1.89	2.02	
2005-09	1.40	1.56	1.70	1.93	
2005-10	1.70	1.82	1.94	2.09	
2005-11	1.97	2.03	2.06	2.16	
2005-12	2.09	2.10	2.12	2.14	
2006-01	1.93	1.98	2.01	2.05	
2006-02	1.98	2.02	2.05	2.01	
2006-03	2.09	2.15	2.20	2.17	
2006-04	2.26	2.34	2.41	2.43	
2006-05	2.30	2.36	2.45	2.48	
2006-06	2.45	2.48	2.53	2.54	
2006-07	2.46	2.48	2.51	2.52	
2006-08	2.27	2.29	2.29	2.31	
2006-09	2.38	2.35	2.32	2.31	
2006-10	2.51	2.45	2.41	2.38	
2006-11	2.41	2.35	2.29	2.23	
2006-12	2.28	2.28	2.25	2.26	
2007-01	2.47	2.47	2.44	2.42	
2007-02	2.34	2.38	2.36	2.38	
2007-03	2.04	2.14	2.18	2.27	
2007-04	2.12	2.20	2.26	2.35	
2007-05	2.29	2.32	2.37	2.45	
2007-06	2.65	2.67	2.69	2.67	
2007-07	2.60	2.63	2.64	2.62	
2007-08	2.39	2.45	2.44	2.47	
2007-09	2.14	2.24	2.26	2.30	
2007-10	2.01	2.15	2.20	2.26	
2007-11	1.35	1.65	1.77	1.99	
2007-12	1.27	1.62	1.79	2.08	
2008-01	0.86	1.24	1.47	1.81	
2008-02	0.65	1.09	1.41	1.87	
2008-03	0.23	0.73	1.09	1.76	
2008-04	0.62	1.00	1.36	1.91	
2008-05	0.79	1.16	1.46	2.00	
2008-06	0.97	1.35	1.63	2.19	
2008-07	0.84	1.24	1.57	2.09	
2008-08	1.15	1.47	1.68	2.15	
2008-09	1.55	1.71	1.85	2.25	
2008-10	2.75	2.96	2.75	2.87	
2008-11	3.69	3.84	2.89	3.00	
2008-12	1.76	1.96	2.17	2.32	
2009-01	1.59	1.72	1.91	2.46	
2009-02	1.29	1.48	1.75	2.31	
2009-03	1.23	1.43	1.71	2.26	
2009-04	1.11	1.29	1.57	2.22	
2009-05	1.07	1.34	1.72	2.36	
2009-06	1.18	1.48	1.86	2.36	
2009-07	1.18	1.44	1.82	2.31	
2009-08	1.29	1.49	1.77	2.22	
2009-09	1.03	1.29	1.64	2.13	
2009-10	0.83	1.12	1.48	2.04	
2009-11	0.48	0.84	1.28	1.90	
2009-12	0.43	0.86	1.36	1.99	
2010-01	0.42	0.85	1.37	2.00	TIPS-30
2010-02	0.42	0.90	1.42	2.03	2.16
2010-03	0.56	1.08	1.51	1.98	2.15
2010-04	0.62	1.10	1.50	1.90	2.05
2010-05	0.41	0.86	1.31	1.72	1.83
2010-06	0.34	0.76	1.26	1.69	1.77
2010-07	0.34	0.73	1.24	1.80	1.87
2010-08	0.13	0.51	1.02	1.65	1.76
2010-09	0.13	0.46	0.91	1.58	1.66
2010-10	-0.32	0.02	0.53	1.32	1.44
2010-11	-0.21	0.17	0.67	1.44	1.61
2010-12	0.21	0.65	1.04	1.67	1.89
2011-01	0.06	0.62	1.06	1.70	1.97
2011-02	0.25	0.84	1.24	1.85	2.13
2011-03	-0.09	0.54	0.96	1.58	1.89
2011-04	-0.14	0.49	0.86	1.48	1.79
2011-05	-0.34	0.29	0.78	1.47	1.77
2011-06	-0.38	0.21	0.76	1.53	1.78
2011-07	-0.49	0.09	0.62	1.36	1.62
2011-08	-0.75	-0.36	0.14	0.81	1.10
2011-09	-0.72	-0.39	0.08	0.69	1.02
2011-10	-0.63	-0.28	0.19	0.72	0.99
2011-11	-0.86	-0.46	0.00	0.55	0.78
2011-12	-0.78	-0.44	-0.03	0.56	0.78
2012-01	-0.92	-0.55	-0.11	0.51	0.74
2012-02	-1.11	-0.69	-0.25	0.45	0.72
2012-03	-1.03	-0.57	-0.14	0.56	0.87
2012-04	**-1.06**	**-0.65**	**-0.21**	**0.50**	**0.79**
2012-05	**-1.12**	**-0.79**	**-0.34**	**0.44**	**0.68**
2012-06	**-1.05**	**-0.82**	**-0.50**	**0.10**	**0.50**
2012-07	-1.15	-0.92	-0.60	-0.01	0.39
2012-08	-1.19	-0.94	-0.59	0.06	0.47
2012-09	-1.47	-1.17	-0.71	0.02	0.44
2012-10	**-1.47**	**-1.18**	**-0.75**	**-0.01**	**0.41**
2012-11	**-1.38**	**-1.13**	**-0.77**	**-0.06**	**0.35**
2012-12	**-1.40**	**-1.13**	**-0.76**	**0.00**	**0.33**
2013-01	-1.39	-1.04	-0.61	0.20	0.48
2013-02	-1.39	-0.94	-0.57	0.19	0.57
2013-03	-1.43	-0.97	-0.59	0.19	0.62
2013-04	**-1.38**	**-0.97**	**-0.65**	**0.07**	**0.48**
2013-05	**-1.14**	**-0.69**	**-0.36**	**0.35**	**0.72**
2013-06	**-0.59**	**-0.21**	**0.25**	**0.98**	**1.21**
2013-07	-0.45	0.02	0.46	1.09	1.34
2013-08	-0.33	0.15	0.55	1.16	1.44
2013-09	-0.17	0.34	0.66	1.22	1.50
2013-10	**-0.41**	**0.11**	**0.43**	**1.05**	**1.37**
2013-11	**-0.38**	**0.18**	**0.55**	**1.20**	**1.51**
2013-12	**-0.09**	**0.47**	**0.74**	**1.32**	**1.61**
2014-01	-0.09	0.45	0.63	1.17	1.44
2014-02	-0.26	0.30	0.55	1.12	1.40
2014-03	-0.14	0.37	0.56	1.05	1.33
2014-04	**-0.11**	**0.38**	**0.54**	**0.98**	**1.23**
2014-05	**-0.34**	**0.21**	**0.37**	**0.82**	**1.08**
2014-06	**-0.29**	**0.23**	**0.37**	**0.84**	**1.11**
2014-07	-0.27	0.18	0.28	0.72	0.98
2014-08	-0.21	0.15	0.22	0.64	0.90
2014-09	0.10	0.38	0.46	0.81	1.05
2014-10	**0.06**	**0.32**	**0.38**	**0.74**	**0.96**
2014-11	**0.14**	**0.37**	**0.45**	**0.77**	**0.99**
2014-12	**0.37**	**0.47**	**0.51**	**0.73**	**0.89**
2015-01	0.17	0.24	0.27	0.50	0.66
2015-02	0.11	0.22	0.26	0.52	0.73
2015-03	0.04	0.23	0.28	0.55	0.73
2015-04	**-0.26**	**-0.01**	**0.08**	**0.42**	**0.65**
2015-05	**-0.10**	**0.27**	**0.33**	**0.70**	**0.96**
2015-06	**0.05**	**0.39**	**0.50**	**0.89**	**1.13**
2015-07	0.14	0.42	0.50	0.87	1.11
2015-08	0.31	0.49	0.56	0.87	1.08
2015-09	0.33	0.52	0.65	1.01	1.24
2015-10	**0.21**	**0.39**	**0.57**	**0.98**	**1.22**
2015-11	**0.40**	**0.55**	**0.69**	**1.03**	**1.25**
2015-12	**0.46**	**0.59**	**0.73**	**1.06**	**1.26**
2016-01	0.33	0.49	0.67	1.05	1.26
2016-02	0.14	0.30	0.47	0.85	1.09
2016-03	-0.03	0.16	0.34	0.73	0.99
2016-04	**-0.22**	**-0.03**	**0.19**	**0.60**	**0.86**
2016-05	**-0.22**	**-0.04**	**0.21**	**0.64**	**0.86**
2016-06	**-0.27**	**-0.07**	**0.17**	**0.63**	**0.82**
2016-07	-0.32	-0.16	0.04	0.42	0.61
2016-08	-0.17	-0.06	0.09	0.43	0.62
2016-09	-0.17	-0.05	0.12	0.47	0.64
2016-10	**-0.26**	**-0.10**	**0.10**	**0.49**	**0.69**
2016-11	**-0.07**	**0.11**	**0.32**	**0.69**	**0.86**
2016-12	**0.15**	**0.36**	**0.56**	**0.89**	**1.04**
2017-01	0.03	0.27	0.42	0.74	0.92
2017-02	0.01	0.29	0.40	0.73	0.93
2017-03	0.18	0.42	0.49	0.79	0.99
2017-04	**0.08**	**0.28**	**0.39**	**0.72**	**0.91**
2017-05	**0.09**	**0.29**	**0.47**	**0.80**	**0.99**
2017-06	**0.14**	**0.32**	**0.46**	**0.75**	**0.93**
2017-07	0.23	0.42	0.55	0.84	1.01
2017-08	0.16	0.35	0.43	0.74	0.93
2017-09	0.12	0.31	0.37	0.67	0.87
2017-10	**0.25**	**0.42**	**0.50**	**0.77**	**0.94**
2017-11	**0.30**	**0.43**	**0.50**	**0.72**	**0.87**
2017-12	**0.42**	**0.48**	**0.50**	**0.68**	**0.80**

Monthly https://www.federalreserve.gov/datadownload/Choose.aspx?rel=H15

UST-05m	5				RIFLGFCY05_N.M
UST-07m	7				RIFLGFCY07_N.M
UST-10m	10	**Year**	**H.15 ID**		RIFLGFCY10_N.M
UST-20m	20				RIFLGFCY20_N.M
UST-30m	30				RIFLGFCY30_N.M

Month	UST-05m	UST-07m	UST-10m	UST-20m	UST-30m
2003-01	3.05	3.60	4.05	5.02	
2003-02	2.90	3.45	3.90	4.87	
2003-03	2.78	3.34	3.81	4.82	
2003-04	2.93	3.47	3.96	4.91	
2003-05	2.52	3.07	3.57	4.52	
2003-06	2.27	2.84	3.33	4.34	
2003-07	2.87	3.45	3.98	4.92	
2003-08	3.37	3.96	4.45	5.39	
2003-09	3.18	3.74	4.27	5.21	
2003-10	3.19	3.75	4.29	5.21	
2003-11	3.29	3.81	4.30	5.17	
2003-12	3.27	3.79	4.27	5.11	
2004-01	3.12	3.65	4.15	5.01	
2004-02	3.07	3.59	4.08	4.94	
2004-03	2.79	3.31	3.83	4.72	
2004-04	3.39	3.89	4.35	5.16	
2004-05	3.85	4.31	4.72	5.46	
2004-06	3.93	4.35	4.73	5.45	
2004-07	3.69	4.11	4.50	5.24	
2004-08	3.47	3.90	4.28	5.07	
2004-09	3.36	3.75	4.13	4.89	
2004-10	3.35	3.75	4.10	4.85	
2004-11	3.53	3.88	4.19	4.89	
2004-12	3.60	3.93	4.23	4.88	
2005-01	3.71	3.97	4.22	4.77	
2005-02	3.77	3.97	4.17	4.61	
2005-03	4.17	4.33	4.50	4.89	
2005-04	4.00	4.16	4.34	4.75	
2005-05	3.85	3.94	4.14	4.56	
2005-06	3.77	3.86	4.00	4.35	
2005-07	3.98	4.06	4.18	4.48	
2005-08	4.12	4.18	4.26	4.53	
2005-09	4.01	4.08	4.20	4.51	
2005-10	4.33	4.38	4.46	4.74	
2005-11	4.45	4.48	4.54	4.83	
2005-12	4.39	4.41	4.47	4.73	
2006-01	4.35	4.37	4.42	4.65	UST-30
2006-02	4.57	4.56	4.57	4.73	4.54
2006-03	4.72	4.71	4.72	4.91	4.73
2006-04	4.90	4.94	4.99	5.22	5.06
2006-05	5.00	5.03	5.11	5.35	5.20
2006-06	5.07	5.08	5.11	5.29	5.15
2006-07	5.04	5.05	5.09	5.25	5.13
2006-08	4.82	4.83	4.88	5.08	5.00
2006-09	4.67	4.68	4.72	4.93	4.85
2006-10	4.69	4.69	4.73	4.94	4.85
2006-11	4.58	4.58	4.60	4.78	4.69
2006-12	4.53	4.54	4.56	4.78	4.68
2007-01	4.75	4.75	4.76	4.95	4.85
2007-02	4.71	4.71	4.72	4.93	4.82
2007-03	4.48	4.50	4.56	4.81	4.72
2007-04	4.59	4.62	4.69	4.95	4.87
2007-05	4.67	4.69	4.75	4.98	4.90
2007-06	5.03	5.05	5.10	5.29	5.20
2007-07	4.88	4.93	5.00	5.19	5.11
2007-08	4.43	4.53	4.67	5.00	4.93
2007-09	4.20	4.33	4.52	4.84	4.79
2007-10	4.20	4.33	4.53	4.83	4.77
2007-11	3.67	3.87	4.15	4.56	4.52
2007-12	3.49	3.74	4.10	4.57	4.53
2008-01	2.98	3.31	3.74	4.35	4.33
2008-02	2.78	3.21	3.74	4.49	4.52
2008-03	2.48	2.93	3.51	4.36	4.39
2008-04	2.84	3.19	3.68	4.44	4.44
2008-05	3.15	3.46	3.88	4.60	4.60
2008-06	3.49	3.73	4.10	4.74	4.69
2008-07	3.30	3.60	4.01	4.62	4.57
2008-08	3.14	3.46	3.89	4.53	4.50
2008-09	2.88	3.25	3.69	4.32	4.27
2008-10	2.73	3.19	3.81	4.45	4.17
2008-11	2.29	2.82	3.53	4.27	4.00
2008-12	1.52	1.89	2.42	3.18	2.87
2009-01	1.60	1.98	2.52	3.46	3.13
2009-02	1.87	2.30	2.87	3.83	3.59
2009-03	1.82	2.42	2.82	3.78	3.64
2009-04	1.86	2.47	2.93	3.84	3.76
2009-05	2.13	2.81	3.29	4.22	4.23
2009-06	2.71	3.37	3.72	4.51	4.52
2009-07	2.46	3.14	3.56	4.38	4.41
2009-08	2.57	3.21	3.59	4.33	4.37
2009-09	2.37	3.02	3.40	4.14	4.19
2009-10	2.33	2.96	3.39	4.16	4.19
2009-11	2.23	2.92	3.40	4.24	4.31
2009-12	2.34	3.07	3.59	4.40	4.49
2010-01	2.48	3.21	3.73	4.50	4.60
2010-02	2.36	3.12	3.69	4.48	4.62
2010-03	2.43	3.16	3.73	4.49	4.64
2010-04	2.58	3.28	3.85	4.53	4.69
2010-05	2.18	2.86	3.42	4.11	4.29
2010-06	2.00	2.66	3.20	3.95	4.13
2010-07	1.76	2.43	3.01	3.80	3.99
2010-08	1.47	2.10	2.70	3.52	3.80
2010-09	1.41	2.05	2.65	3.47	3.77
2010-10	1.18	1.85	2.54	3.52	3.87
2010-11	1.35	2.02	2.76	3.82	4.19
2010-12	1.93	2.66	3.29	4.17	4.42
2011-01	1.99	2.72	3.39	4.28	4.52
2011-02	2.26	2.96	3.58	4.42	4.65
2011-03	2.11	2.80	3.41	4.27	4.51
2011-04	2.17	2.84	3.46	4.28	4.50
2011-05	1.84	2.51	3.17	4.01	4.29
2011-06	1.58	2.29	3.00	3.91	4.23
2011-07	1.54	2.28	3.00	3.95	4.27
2011-08	1.02	1.63	2.30	3.24	3.65
2011-09	0.90	1.42	1.98	2.83	3.18
2011-10	1.06	1.62	2.15	2.87	3.13
2011-11	0.91	1.45	2.01	2.72	3.02
2011-12	0.89	1.43	1.98	2.67	2.98
2012-01	0.84	1.38	1.97	2.70	3.03
2012-02	0.83	1.37	1.97	2.75	3.11
2012-03	1.02	1.56	2.17	2.94	3.28
2012-04	**0.89**	**1.43**	**2.05**	**2.82**	**3.18**
2012-05	**0.76**	**1.21**	**1.80**	**2.53**	**2.93**
2012-06	**0.71**	**1.08**	**1.62**	**2.31**	**2.70**
2012-07	0.62	0.98	1.53	2.22	2.59
2012-08	0.71	1.14	1.68	2.40	2.77
2012-09	0.67	1.12	1.72	2.49	2.88
2012-10	**0.71**	**1.15**	**1.75**	**2.51**	**2.90**
2012-11	**0.67**	**1.08**	**1.65**	**2.39**	**2.80**
2012-12	**0.70**	**1.13**	**1.72**	**2.47**	**2.88**
2013-01	0.81	1.30	1.91	2.68	3.08
2013-02	0.85	1.35	1.98	2.78	3.17
2013-03	0.82	1.32	1.96	2.78	3.16
2013-04	**0.71**	**1.15**	**1.76**	**2.55**	**2.93**
2013-05	**0.84**	**1.31**	**1.93**	**2.73**	**3.11**
2013-06	**1.20**	**1.71**	**2.30**	**3.07**	**3.40**
2013-07	1.40	1.99	2.58	3.31	3.61
2013-08	1.52	2.15	2.74	3.49	3.76
2013-09	1.60	2.22	2.81	3.53	3.79
2013-10	**1.37**	**1.99**	**2.62**	**3.38**	**3.68**
2013-11	**1.37**	**2.07**	**2.72**	**3.50**	**3.80**
2013-12	**1.58**	**2.29**	**2.90**	**3.63**	**3.89**
2014-01	1.65	2.29	2.86	3.52	3.77
2014-02	1.52	2.15	2.71	3.38	3.66
2014-03	1.64	2.23	2.72	3.35	3.62
2014-04	**1.70**	**2.27**	**2.71**	**3.27**	**3.52**
2014-05	**1.59**	**2.12**	**2.56**	**3.12**	**3.39**
2014-06	**1.68**	**2.19**	**2.60**	**3.15**	**3.42**
2014-07	1.70	2.17	2.54	3.07	3.33
2014-08	1.63	2.08	2.42	2.94	3.20
2014-09	1.77	2.22	2.53	3.01	3.26
2014-10	**1.55**	**1.98**	**2.30**	**2.77**	**3.04**
2014-11	**1.62**	**2.03**	**2.33**	**2.76**	**3.04**
2014-12	**1.64**	**1.98**	**2.21**	**2.55**	**2.83**
2015-01	1.37	1.67	1.88	2.20	2.46
2015-02	1.47	1.79	1.98	2.34	2.57
2015-03	1.52	1.84	2.04	2.41	2.63
2015-04	**1.35**	**1.69**	**1.94**	**2.33**	**2.59**
2015-05	**1.54**	**1.93**	**2.20**	**2.69**	**2.96**
2015-06	**1.68**	**2.10**	**2.36**	**2.85**	**3.11**
2015-07	1.63	2.04	2.32	2.77	3.07
2015-08	1.54	1.91	2.17	2.55	2.86
2015-09	1.49	1.88	2.17	2.62	2.95
2015-10	**1.39**	**1.76**	**2.07**	**2.50**	**2.89**
2015-11	**1.67**	**2.02**	**2.26**	**2.69**	**3.03**
2015-12	**1.70**	**2.04**	**2.24**	**2.61**	**2.97**
2016-01	1.52	1.85	2.09	2.49	2.86
2016-02	1.22	1.53	1.78	2.20	2.62
2016-03	1.38	1.68	1.89	2.28	2.68
2016-04	**1.26**	**1.57**	**1.81**	**2.21**	**2.62**
2016-05	**1.30**	**1.60**	**1.81**	**2.22**	**2.63**
2016-06	**1.17**	**1.44**	**1.64**	**2.02**	**2.45**
2016-07	1.07	1.33	1.50	1.82	2.23
2016-08	1.13	1.40	1.56	1.89	2.26
2016-09	1.18	1.46	1.63	2.02	2.35
2016-10	**1.27**	**1.56**	**1.76**	**2.17**	**2.50**
2016-11	**1.60**	**1.93**	**2.14**	**2.54**	**2.86**
2016-12	**1.96**	**2.29**	**2.49**	**2.84**	**3.11**
2017-01	1.92	2.23	2.43	2.75	3.02
2017-02	1.90	2.22	2.42	2.76	3.03
2017-03	2.01	2.30	2.48	2.83	3.08
2017-04	**1.82**	**2.10**	**2.30**	**2.67**	**2.94**
2017-05	**1.84**	**2.11**	**2.30**	**2.70**	**2.96**
2017-06	**1.77**	**2.01**	**2.19**	**2.54**	**2.80**
2017-07	1.87	2.13	2.32	2.65	2.88
2017-08	1.78	2.03	2.21	2.55	2.80
2017-09	1.80	2.03	2.20	2.53	2.78
2017-10	**1.98**	**2.20**	**2.36**	**2.65**	**2.88**
2017-11	**2.05**	**2.23**	**2.35**	**2.60**	**2.80**
2017-12	**2.18**	**2.32**	**2.40**	**2.60**	**2.77**

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Annual https://www.federalreserve.gov/datadownload/Choose.aspx?rel=H15

TIPS-05a	5				RIFLGFCY05_XII_N.A
TIPS-07a	7				RIFLGFCY07_XII_N.A
TIPS-10a	10	**Year**	**Inflation Indexed**	**H.15 ID**	RIFLGFCY10_XII_N.A
TIPS-20a	20				RIFLGFCY20_XII_N.A
TIPS-30a	30				RIFLGFCY30_XII_N.A

Year	TIPS-05a	TIPS-07a	TIPS-10a	TIPS-20a	TIPS-30a
2003	1.27	1.73	2.06		
2004	1.04	1.45	1.83	2.14	
2005	1.50	1.83	1.81	1.97	
2006	2.28	2.29	2.31	2.31	
2007	2.15	2.25	2.29	2.36	
2008	1.30	1.63	1.77	2.18	
2009	1.06	1.32	1.66	2.21	
2010	0.26	0.68	1.15	1.73	1.82
2011	-0.41	0.09	0.55	1.19	1.47
2012	-1.19	-0.87	-0.48	0.22	0.56
2013	0.76	-0.29	0.07	0.75	1.07
2014	-0.09	0.32	0.44	0.86	1.11
2015	0.15	0.36	0.45	0.78	1.00
2016	-0.01	0.07	0.27	0.65	0.86
2017	0.17	0.36	0.46	0.75	0.92
2018	0.78	0.82	0.83	0.93	1.01
2019	0.35	0.37	0.40	0.60	0.78
2020	-0.79	-0.71	-0.60	-0.31	-0.11
2021	-1.69	-1.26	-0.91	-0.43	-0.2
2022	0.22	0.33	0.43	0.64	0.76
2023	1.80	1.73	1.68	1.73	1.8

Annual

UST-05a	5				RIFLGFCY05_N.A
UST-07a	7				RIFLGFCY07_N.A
UST-10a	10	**Year**	**H.15 ID**		RIFLGFCY10_N.A
UST-20a	20				RIFLGFCY20_N.A
UST-30a	30				RIFLGFCY30_N.A

Year	UST-05a	UST-07a	UST-10a	UST-20a	UST-30a
2003	2.97	3.52	4.01	4.96	
2004	3.43	3.87	4.27	5.04	
2005	4.05	4.15	4.29	4.64	
2006	4.75	4.76	4.80	5.00	4.91
2007	4.43	4.51	4.63	4.91	4.84
2008	2.80	3.17	3.66	4.36	4.28
2009	2.20	2.82	3.26	4.11	4.08
2010	1.93	2.62	3.22	4.03	4.25
2011	1.52	2.16	2.78	3.62	3.91
2012	0.76	1.22	1.80	2.54	2.92
2013	1.17	1.74	2.35	3.12	3.45
2014	1.64	2.14	2.54	3.07	3.34
2015	1.53	1.89	2.14	2.55	2.

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Value Line (VL)
Natural Gas and Water Utilities

April 18, 2024

Stocks of a number of companies in *Value Line's* Natural Gas Utility Industry have been fairly rangebound since our last report in November. But that should come as no surprise, given that historical price movements of this typically defensive sector have tended to be on the steady side. It's also important to mention that the big draw here is these equities' reliable, healthy amounts of dividend income (which are sufficiently covered by corporate earnings). What's more, at recent quotations, 3- to 5-year capital appreciation potential for some of the stocks in our universe looks decent, resulting in solid total return possibilities.

Natural Gas Prices

Natural gas quotations have weakened significantly over the past few months reflecting, among other factors, heightened production levels and mild winter weather. Although this scenario does not augur well for companies that produce this commodity, regulated utility units generally benefit. That's partially because diminished gas pricing tends to lead to lower prices for customers, which may bring down bad-debt expense. Moreover, there is an increased possibility that homeowners will convert from alternative fuel sources, such as propane or oil, to natural gas. (At present, it's estimated that roughly half of all households in the United States use natural gas.) It should be mentioned, however, that nonregulated operations (discussed below) tend to underperform when gas pricing is at subdued levels.

Nonregulated Businesses

Some of our industry participants have dedicated substantial resources to the nonregulated arena, which includes pipelines and energy marketing & trading services, and we see this trend continuing in the future. Indeed, these units offer opportunities for utilities to diversify their revenue streams. Also, the fact that nonregulated segments can provide potential upside to earnings per share is notable, since the return on equity is limited by the regulatory state commissions (generally in the 9%-11% range) on the regulated divisions.

Interest Rates

In January, the Federal Reserve announced that it would keep interest rates steady while waiting to see if additional actions were necessary to combat inflation, which has eased some during the past year but remains elevated. (The central bank has been engaged in its fastest rate-increase cycle since the 1980s.) So, this raises the question, "How does a rising interest rate environment affect the participants in the Natural Gas Utility Industry?" One way is by increasing borrowing costs, an especially important factor because these companies tend to maintain substantial levels of debt. Furthermore, rising interest rates might make bonds more attractive to conservative, yield-oriented investors, the very ones who are typically drawn to utility stocks.

Attractive Payouts

The main appeal of utility equities is their dividends, which tend to be adequately covered by corporate profits.

INDUSTRY TIMELINESS: 66 (of 93)

(It's important to state that the Financial Strength ratings for more than half of the nine companies in our category are at least an A, and the lowest is a respectable B++.) At the time of this industry review, the average yield for the group was approximately 4.3%, nearly double the *Value Line* median of 2.2%. Standouts include *UGI Corp.*, *ONE Gas, Inc.*, *Northwest Natural Holding Co.*, and *Spire Inc.* When the financial markets experience heightened volatility (which seems to be more often the case these days), healthy dividend yields provide a measure of much-needed stability.

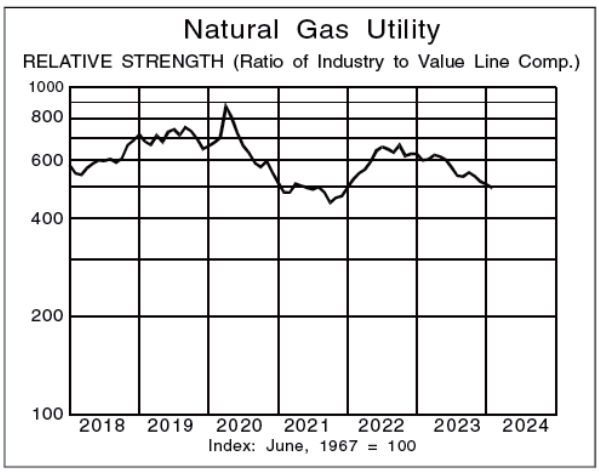
Prospects Out To Late Decade

We are optimistic, overall, about the industry's long-term operating performance. Natural gas should remain an abundant resource in the U.S., brought about partially by new technologies, so a shortage does not appear likely in the years ahead. Too, there are limited alternatives for the services the companies in this sector offer. Furthermore, it's a challenge for new entrants in the market, given such factors as the size of existing competitors and the substantial initial capital outlays that are required. Finally, the country's population, now numbering more than 330 million, should stay on a steady, upward course, which augurs well for future demand for utility services.

Conclusion

None of the equities in our Natural Gas Utility Industry stand out for Timeliness, at this juncture, besides *UGI Corp*. Nevertheless, they ought to be of interest to income-focused investors with a conservative orientation, given that these good-yielding issues boast high marks for Price Stability, and the majority are ranked 1 (Highest) or 2 (Above Average) for Safety. Consider, too, that there are some appealing choices for capital appreciation potential for both the 18-month horizon and over the pull to 2027-2029. As always, our subscribers are advised to carefully examine the following reports before committing funds.

Frederick L. Harris, III



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ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE 114.00 | P/E RATIO 17.4 (Trailing: 18.6, Median: 20.0) | RELATIVE P/E RATIO 1.01 | DIV'D YLD 2.9% | VALUE LINE

TIMELINESS 4 Lowered 2/16/24
SAFETY 1 Raised 6/6/14
TECHNICAL 2 Raised 2/9/24
BETA .85 (1.00 = Market)

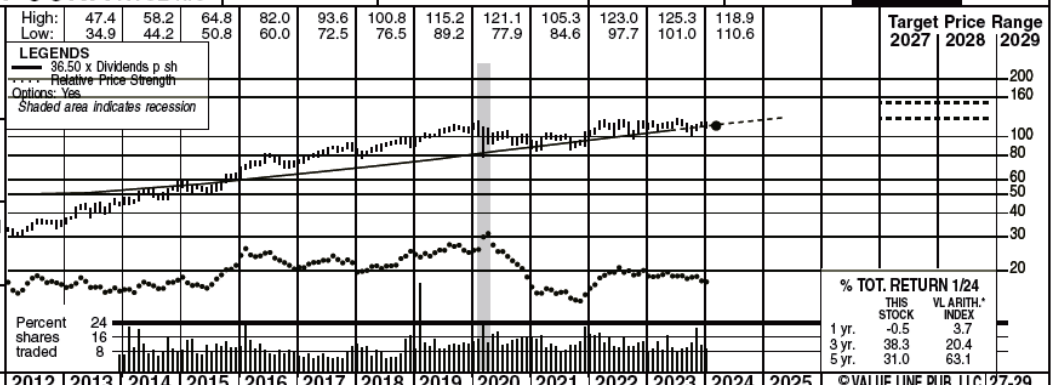
18-Month Target Price Range
Low-High Midpoint (% to Mid)
$98-$153 $126 (10%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	150	(+30%)	10%
Low	125	(+10%)	6%

Institutional Decisions

	1Q2023	2Q2023	3Q2023
to Buy	337	314	322
to Sell	258	281	280
Hld's(000)	131736	136508	137279



2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
79.52	53.69	53.12	48.15	38.10	42.88	49.22	40.82	32.23	26.01	28.00	24.32	22.41	25.73	29.82	28.79	*26.75*	*27.85*	Revenues per sh [A]	*37.15*
4.19	4.29	4.64	4.72	4.76	5.14	5.42	5.81	6.19	6.62	7.24	7.57	8.03	8.64	9.30	10.04	*10.75*	*11.55*	"Cash Flow" per sh	*13.65*
2.00	1.97	2.16	2.26	2.10	2.50	2.96	3.09	3.38	3.60	4.00	4.35	4.72	5.12	5.60	6.10	*6.55*	*7.00*	Earnings per sh [AB]	*8.35*
1.30	1.32	1.34	1.36	1.38	1.40	1.48	1.56	1.68	1.80	1.94	2.10	2.30	2.50	2.72	2.96	*3.22*	*3.46*	Div'ds Decl'd per sh [C]■	*4.25*
5.20	5.51	6.02	6.90	8.12	9.32	8.32	9.61	10.46	10.72	13.19	14.19	15.38	14.87	17.35	18.90	*18.70*	*19.00*	Cap'l Spending per sh	*20.00*
22.60	23.52	24.16	24.98	26.14	28.47	30.74	31.48	33.32	36.74	42.87	48.18	53.95	59.71	66.85	73.20	*74.90*	*78.25*	Book Value per sh	*83.50*
90.81	92.55	90.16	90.30	90.24	90.64	100.39	101.48	103.93	106.10	111.27	119.34	125.88	132.42	140.90	148.49	*155.00*	*158.00*	Common Shs Outst'g [D]	*175.00*
13.6	12.5	13.2	14.4	15.9	15.9	16.1	17.5	20.8	22.0	21.7	23.2	22.3	18.8	19.3	18.7	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*16.5*
.82	.83	.84	.90	1.01	.89	.85	.88	1.09	1.11	1.17	1.24	1.15	1.02	1.12	1.08			Relative P/E Ratio	*.90*
4.8%	5.3%	4.7%	4.2%	4.1%	3.5%	3.1%	2.9%	2.4%	2.3%	2.2%	2.1%	2.2%	2.6%	2.5%	2.6%			Avg Ann'l Div'd Yield	*3.1%*
4940.9	4142.1	3349.9	2759.7	3115.5	2901.8	2821.1	3407.5	4201.7	4275.4	*4145*	*4400*	Revenues ($mill) [A]	*6500*
289.8	315.1	350.1	382.7	444.3	511.4	580.5	665.6	774.4	885.9	*1000*	*1100*	Net Profit ($mill)	*1475*
39.2%	38.3%	36.4%	36.6%	27.0%	21.4%	19.5%	18.8%	9.1%	11.4%	*15.0%*	*16.0%*	Income Tax Rate	*25.0%*
5.9%	7.6%	10.5%	13.9%	14.3%	17.6%	20.6%	19.5%	18.4%	20.7%	*24.1%*	*25.0%*	Net Profit Margin	*22.7%*
44.3%	43.5%	38.7%	44.0%	34.3%	38.0%	40.0%	38.4%	37.9%	37.9%	*40.0%*	*40.0%*	Long-Term Debt Ratio	*40.0%*
55.7%	56.5%	61.3%	56.0%	65.7%	62.0%	60.0%	61.6%	62.1%	62.1%	*60.0%*	*60.0%*	Common Equity Ratio	*60.0%*
5542.2	5650.2	5651.8	6965.7	7263.6	9279.7	11323	12837	15180	17509	*19350*	*20600*	Total Capital ($mill)	*24350*
6725.9	7430.6	8280.5	9259.2	10371	11788	13355	15064	17240	19607	*20700*	*21800*	Net Plant ($mill)	*25500*
6.4%	6.6%	7.2%	6.4%	6.9%	6.1%	5.5%	5.5%	5.4%	5.5%	*6.5%*	*6.5%*	Return on Total Cap'l	*7.5%*
9.4%	9.9%	10.1%	9.8%	9.3%	8.9%	8.5%	8.4%	8.2%	8.1%	*8.5%*	*9.0%*	Return on Shr. Equity	*10.0%*
9.4%	9.9%	10.1%	9.8%	9.3%	8.9%	8.5%	8.4%	8.2%	8.1%	*8.5%*	*9.0%*	Return on Com Equity	*10.0%*
4.7%	4.9%	5.1%	4.9%	4.8%	4.6%	4.4%	4.3%	4.2%	4.2%	*4.5%*	*4.5%*	Retained to Com Eq	*5.0%*
50%	51%	50%	50%	48%	48%	49%	49%	49%	49%	*50%*	*50%*	All Div'ds to Net Prof	*50%*

CAPITAL STRUCTURE as of 12/31/23
Total Debt $7540.8 mill. Due in 5 Yrs $915.0 mill.
LT Debt $7529.3 mill. LT Interest $135.0 mill.
(LT interest earned: 8.3x; total interest coverage: 8.3x)
Leases, Uncapitalized Annual rentals $41.3 mill.

Pfd Stock None

Pension Assets-9/23 $502.4 mill.
Oblig. $431.6 mill.

Common Stock 150,839,709 shs.
as of 2/2/24

MARKET CAP: $17.2 billion (Large Cap)

CURRENT POSITION ($MILL.)

	2022	2023	12/31/23
Cash Assets	51.6	15.4	278.3
Other	2996.1	870.4	1401.4
Current Assets	3047.7	885.8	1679.7
Accts Payable	496.0	336.1	416.7
Debt Due	2386.4	253.4	11.5
Other	720.2	763.1	742.3
Current Liab.	3602.6	1352.6	1170.5
Fix. Chg. Cov.	1238%	1059%	1080%

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-4.0%	-.5%	*5.0%*
"Cash Flow"	6.5%	7.0%	*6.5%*
Earnings	9.5%	9.0%	*7.0%*
Dividends	7.0%	8.5%	*7.5%*
Book Value	9.5%	12.0%	*4.0%*

QUARTERLY REVENUES ($ mill.) [A]

Fiscal Year Ends	Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	914.5	1319.1	605.6	568.3	3407.5
2022	1012.8	1649.8	816.4	722.7	4201.7
2023	1484.0	1541.0	662.7	587.7	4275.4
2024	1158.5	*1600*	*786.5*	*600*	*4145*
2025	*1225*	*1700*	*840*	*635*	*4400*

EARNINGS PER SHARE [A B E]

Fiscal Year Ends	Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	1.71	2.30	.78	.37	5.12
2022	1.86	2.37	.92	.51	5.60
2023	1.91	2.48	.94	.80	6.10
2024	2.08	*2.53*	*1.06*	*.88*	*6.55*
2025	*2.21*	*2.65*	*1.17*	*.97*	*7.00*

QUARTERLY DIVIDENDS PAID [C]■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.575	.575	.575	.625	2.35
2021	.625	.625	.625	.68	2.56
2022	.68	.68	.68	.74	2.78
2023	.74	.74	.74	.805	3.03
2024	805				

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to over three million customers through six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Gas sales breakdown for fiscal 2023: 66.5%, residential; 28.0%, commercial; 3.8%, industrial; and 1.7% other. The company sold Atmos Energy Marketing, 1/17. Officers and directors own approximately .5% of common stock (12/23 Proxy). President and Chief Executive Officer: Kevin Akers. Incorporated: Texas. Address: Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, Texas 75240. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

Atmos Energy started fiscal 2024 with healthy bottom-line results. (The year concludes on September 30th.) First-quarter earnings per share of $2.08 were 9% higher than the $1.91 tally posted in fiscal 2023. That was made possible partly by positive rate-case outcomes. Diminished bad-debt expense helped, too. It should also be mentioned that the current-quarter figure was favorably impacted by legislation to reduce property-tax expenses in Texas. But increased depreciation expense and higher interest expense provided somewhat of an offset. Still, at this juncture, it appears that full-year profits will advance roughly 7%, to $6.55 per share, compared to fiscal 2023's $6.10 total. Regarding next year, share net stands to advance at a similar percentage rate, to $7.00, assuming additional widening of operating margins.

There's sufficient liquidity to satisfy various obligations for quite a while. When the December period ended, cash and equivalents sat at $278.3 million. Moreover, long-term debt looked reasonable (40% of total capital) and short-term commitments were minimal. Also, $3.1 billion in common stock and/or debt securities remained available for issuance (out of $5 billion) under a shelf registration statement expiring in March, 2026. Finally, the company had four undrawn revolving credit facilities aggregating $2.5 billion plus a $1.5 billion commercial paper program.

Prospects out to the end of the decade seem decent. Atmos Energy ranks as one of the nation's biggest natural gas-only distributors, with more than three million customers across several states, including Texas, Louisiana, and Mississippi. Furthermore, we believe the pipeline and storage segment has promising overall expansion opportunities, since it operates in one of the most-active drilling regions in the world. The solid balance sheet is another strength.

What about the stock? Capital appreciation potential over the 18-month span seems worthwhile. However, the dividend yield is lower than the average of *Value Line's* Natural Gas Utility Industry. Meanwhile, ATO shares are unfavorably ranked for Timeliness.

Frederick L. Harris, III February 23, 2024

(A) Fiscal year ends Sept. 30th. (B) Diluted shrs. Excl. nonrec. gains (loss): '10, 5¢; '11, (1¢); '18, $1.43; '20, 17¢. Excludes discontinued operations: '11, 10¢; '12, 27¢; '13, 14¢; '17, 13¢. Next earnings report due early May. (C) Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail. (D) In millions. (E) Qtrs may not add due to change in shrs outstanding.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	100

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CHESAPEAKE UTIL. NYSE-CPK

RECENT PRICE 105.22 | P/E RATIO 20.8 (Trailing: 21.3 Median: 23.0) | RELATIVE P/E RATIO 1.20 | DIV'D YLD 2.4% | VALUE LINE

TIMELINESS 4 Lowered 2/9/24
SAFETY 2 New 6/5/15
TECHNICAL 4 Raised 12/29/23
BETA .80 (1.00 = Market)

18-Month Target Price Range

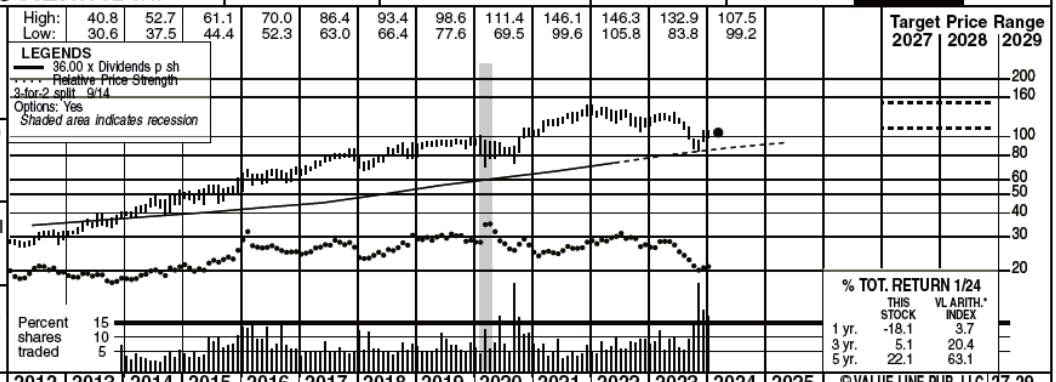
Low-High	Midpoint (% to Mid)
$87-$167	$127 (20%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	150	(+45%)	11%
Low	110	(+5%)	4%

Institutional Decisions

	1Q2023	2Q2023	3Q2023
to Buy	128	107	126
to Sell	97	121	98
Hld's(000)	13346	13342	13495



2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
28.46	19.07	29.93	29.13	27.26	30.73	34.19	30.07	30.60	37.79	43.81	29.24	27.96	32.28	38.37	*36.20*	*38.95*	*42.05*	Revenues per sh	*70.20*
2.50	2.15	3.50	3.69	3.95	4.35	4.73	5.05	5.16	5.42	6.47	6.50	7.37	8.28	8.87	*8.80*	*9.35*	*10.00*	"Cash Flow" per sh	*11.70*
1.39	1.43	1.82	1.91	1.99	2.26	2.47	2.68	2.86	2.68	3.45	3.72	4.21	4.73	4.97	*4.85*	*5.10*	*5.35*	Earnings per sh A	*6.50*
.81	.83	.87	.91	.96	1.01	1.07	1.12	1.19	1.26	1.39	1.55	1.69	1.84	2.03	2.25	*2.44*	*2.60*	Div'ds Decl'd per sh B■	*3.20*
3.00	1.89	3.18	3.28	5.00	6.72	6.66	9.47	10.42	10.73	16.47	11.26	9.48	10.59	7.23	*10.80*	*11.55*	*11.80*	Cap'l Spending per sh	*12.25*
12.02	14.89	15.84	16.78	17.82	19.28	20.59	23.45	27.36	29.75	31.65	34.23	39.92	43.85	46.94	*49.30*	*53.40*	*56.50*	Book Value per sh	*66.40*
10.24	14.09	14.29	14.35	14.40	14.46	14.59	15.27	16.30	16.34	16.38	16.40	17.46	17.66	17.74	*18.50*	*19.00*	*19.50*	Common Shs Outst'g C	*23.50*
14.2	14.2	12.2	14.2	14.8	15.6	17.7	19.1	21.8	27.8	22.9	24.7	21.6	25.6	25.8	*23.7*	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*20.0*
.85	.95	.78	.89	.94	.88	.93	.96	1.14	1.40	1.24	1.32	1.11	1.38	1.49	*1.32*			Relative P/E Ratio	*1.10*
4.1%	4.1%	3.9%	3.4%	3.3%	2.9%	2.4%	2.2%	1.9%	1.7%	1.8%	1.7%	1.9%	1.5%	1.6%	2.0%			Avg Ann'l Div'd Yield	*2.5%*
498.8	459.2	498.9	617.6	717.5	479.6	488.2	570.0	680.7	*670*	*740*	*820*	Revenues ($mill)	*1650*
36.1	40.2	44.7	43.8	56.6	61.1	70.6	83.5	88.4	*90.0*	*97.0*	*105*	Net Profit ($mill)	*155*
39.9%	39.5%	38.8%	39.5%	27.1%	25.6%	25.0%	25.9%	27.4%	*26.0%*	*26.5%*	*27.0%*	Income Tax Rate	*29.0%*
7.2%	8.8%	9.0%	7.1%	7.9%	12.7%	14.5%	14.6%	13.0%	*13.4%*	*13.1%*	*12.8%*	Net Profit Margin	*9.4%*
34.5%	29.4%	23.5%	28.9%	37.9%	43.9%	42.2%	41.5%	41.0%	*43.0%*	*42.0%*	*42.0%*	Long-Term Debt Ratio	*40.0%*
65.5%	70.6%	76.5%	71.1%	62.1%	56.1%	57.8%	58.5%	59.0%	*57.0%*	*58.0%*	*58.0%*	Common Equity Ratio	*60.0%*
458.8	507.5	583.0	683.7	834.5	1001.7	1205.6	1324.0	1411.2	*1600*	*1750*	*1900*	Total Capital ($mill)	*2600*
689.8	855.0	986.7	1126.0	1384.0	1463.8	1601.2	1744.9	1810.5	*1950*	*2175*	*2400*	Net Plant ($mill)	*3000*
8.5%	8.9%	8.6%	7.3%	7.8%	7.2%	6.8%	7.1%	7.1%	*7.0%*	*7.0%*	*7.0%*	Return on Total Cap'l	*7.0%*
12.0%	11.2%	10.0%	9.0%	10.9%	10.9%	10.1%	10.8%	10.6%	*10.0%*	*9.5%*	*9.5%*	Return on Shr. Equity	*10.0%*
12.0%	11.2%	10.0%	9.0%	10.9%	10.9%	10.1%	10.8%	10.6%	*10.0%*	*9.5%*	*9.5%*	Return on Com Equity	*10.0%*
7.4%	6.8%	6.1%	4.9%	6.7%	6.5%	6.2%	6.7%	6.4%	*5.5%*	*5.0%*	*5.0%*	Retained to Com Eq	*5.0%*
38%	40%	39%	45%	39%	40%	38%	38%	40%	*46%*	*48%*	*48%*	All Div'ds to Net Prof	*49%*

CAPITAL STRUCTURE as of 9/30/23
Total Debt $782.4 mill. **Due in 5 Yrs** $334.0 mill.
LT Debt $643.8 mill. **LT Interest** $40.0 mill.
(LT interest earned: 6.0x; total interest coverage: 6.0x) (43% of Cap'l)
Leases, Uncapitalized Annual rentals $2.9 mill.
Pfd Stock None
Pension Assets-12/22 $46.2 mill.
Oblig. $51.6 mill.
Common Stock 17,796,741 shs.
as of 10/27/23

MARKET CAP: $1.9 billion (Small Cap)

CURRENT POSITION ($MILL.)	2021	2022	9/30/23
Cash Assets	5.0	6.2	1.8
Other	168.1	187.8	135.7
Current Assets	173.1	194.0	137.5
Accts Payable	52.6	61.5	53.7
Debt Due	239.6	223.6	138.6
Other	84.2	83.9	96.1
Current Liab.	376.4	369.0	288.4
Fix. Chg. Cov.	771%	692%	710%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '27-'29
Revenues	2.0%	-1.0%	*11.5%*
"Cash Flow"	8.0%	8.5%	*5.5%*
Earnings	9.0%	10.0%	*5.0%*
Dividends	7.0%	8.5%	*8.5%*
Book Value	9.5%	9.0%	*6.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	191.2	111.1	107.3	160.4	570.0
2022	222.9	139.5	131.1	187.2	680.7
2023	218.1	135.6	131.5	*184.8*	*670*
2024	*235*	*160*	*150*	*195*	*740*
2025	*255*	*180*	*170*	*215*	*820*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1.96	.78	.71	1.28	4.73
2022	2.08	.88	.54	1.47	4.97
2023	2.04	.90	.53	*1.38*	*4.85*
2024	*2.10*	*.98*	*.60*	*1.42*	*5.10*
2025	*2.16*	*1.05*	*.66*	*1.48*	*5.35*

Calendar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.405	.405	.44	.44	1.69
2021	.44	.44	.48	.48	1.84
2022	.48	.48	.535	.535	2.03
2023	.535	.535	.59	.59	2.25
2024	.59				

BUSINESS: Chesapeake Utilities Corporation consists of two main units. The Regulated Energy segment distributes natural gas in Delaware, Maryland, and Florida; distributes electricity in Florida; and transmits natural gas on the Delmarva Peninsula and in Florida. The Unregulated Energy operation wholesales and distributes propane; markets natural gas; and provides other unregulated energy services, including midstream services in Ohio. Revenue breakdown for 2022: Regulated Energy, 63.1%; Unregulated Energy, 41.2%; Other, d4.3%. Officers and directors own 2.7% of common stock; BlackRock, 13.9% (3/23 Proxy). Chairman and CEO: Jeffry M. Householder. Inc.: DE. Address: 909 Silver Lake Boulevard, Dover, DE 19904. Tel.: (302) 734-6799. Internet: www.chpk.com.

Chesapeake Utilities just concluded an important agreement with NextEra Energy. It paid that firm $923 million for Florida City Gas (FCG), serving 120,000 residential and commercial customers across eight counties in Florida, including Miami-Dade, Broward, Palm Beach, and Indian River. We like that move partly because it more than doubled the natural gas operations in The Sunshine State, which has bright growth prospects. Another plus is enhanced economies of scale. It's also worth mentioning that the deal was funded via a balanced mix of equity and long-term debt, thus maintaining the company's sound finances.

Another business was brought into the fold. Chesapeake purchased, for an undisclosed amount, the propane operating assets of J.T. Lee and Son's. As a consequence, its geographic footprint extended further into the promising North Carolina market, via the addition of 3,000 customers. Synergistic benefits are probable, as well. So, we would not be surprised to see similar transactions going forward.

It appears that the energy firm posted uninspiring 2023 results. Recall that for the first nine months, profits of $3.47 per share were a few pennies below 2022's $3.50 figure. That can be traced partly to much warmer weather in the northern service territories, especially during the first six months, which constrained customer consumption. Moreover, there were increased interest charges, employee-related expenses, and facilities & maintenance costs. However, the company's performance did benefit from factors such as contributions from a Florida natural gas base rate proceeding, increased propane margins and fees, plus pipeline expansion projects. Still, it seems that, for the entire year, earnings per share sat at around $4.85, modestly below 2022's $4.97 tally. But regarding 2024 and 2025, share net stands to reach $5.10 and $5.35, respectively (a 5% advance for both years), if the business climate cooperates.

The equity does not have much to offer other than decent 18-month capital gains potential. Upside possibilities out to 2027-2029 lack appeal. The dividend yield is not enticing, either, versus those of other Natural Gas Utility stocks we cover.

Frederick L. Harris, III February 23, 2024

(A) Diluted shrs. Excludes nonrecurring gains (loss): '08, (7¢); '15, 6¢; '17, 87¢; '22, 8¢. Excludes discontinued operations: '19, 24¢; '20, 5¢. Quarters for 2019 don't equal total because of rounding. Next earnings report due early May.
(B) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan. Direct stock purchase plan available.
(C) In millions, adjusted for split.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	90
Earnings Predictability	100

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Docket No: UG 490 Staff/108 Muldoon/4

NEW JERSEY RES. NYSE-NJR

RECENT PRICE 42.13 | P/E RATIO 15.0 (Trailing: 18.3, Median: 17.0) | RELATIVE P/E RATIO 0.87 | DIV'D YLD 4.0% | VALUE LINE

TIMELINESS 5 Lowered 1/5/24
SAFETY 2 Lowered 4/17/20
TECHNICAL 4 Lowered 1/5/24
BETA .95 (1.00 = Market)

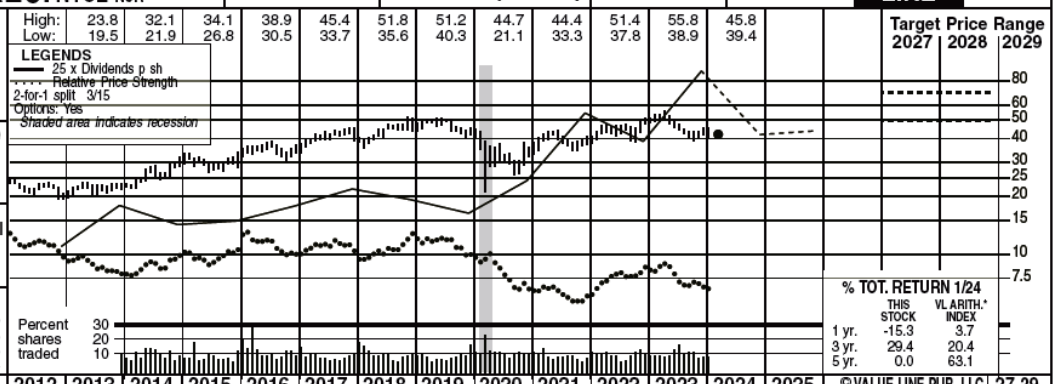
18-Month Target Price Range
Low-High Midpoint (% to Mid)
$31-$51 $41 (-5%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+65%)	16%
Low	50	(+20%)	8%

Institutional Decisions

	1Q2023	2Q2023	3Q2023
to Buy	157	157	153
to Sell	133	156	163
Hld's(000)	73728	71570	69494



2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
45.37	31.17	32.05	36.30	27.08	38.38	44.40	32.09	21.90	26.28	33.24	29.01	20.39	22.71	30.38	20.12	*21.50*	*22.00*	Revenues per sh [A]	*25.00*
1.81	1.58	1.63	1.70	1.86	1.93	2.73	2.52	2.46	2.68	3.72	2.99	3.30	3.36	3.86	4.22	*4.40*	*4.50*	"Cash Flow" per sh	*5.25*
1.35	1.20	1.23	1.29	1.36	1.37	2.08	1.78	1.61	1.73	2.72	1.96	2.07	2.16	2.50	2.70	*2.80*	*2.90*	Earnings per sh [B]	*3.50*
.56	.62	.68	.72	.77	.81	.86	.93	.98	1.04	1.11	1.19	1.27	1.36	1.45	1.56	*1.68*	*1.76*	Div'ds Decl'd per sh [C]■	*1.95*
.86	.90	1.05	1.13	1.26	1.33	1.52	3.76	4.15	3.80	4.39	5.83	4.65	5.42	6.50	5.13	*5.15*	*5.50*	Cap'l Spending per sh	*6.25*
8.64	8.29	8.81	9.36	9.80	10.65	11.48	12.99	13.58	14.33	16.18	17.37	19.26	17.18	19.00	20.40	*22.30*	*23.65*	Book Value per sh [D]	*27.00*
84.12	83.17	82.35	82.89	83.05	83.32	84.20	85.19	85.88	86.32	87.69	89.34	95.80	94.95	95.64	97.57	*100.00*	*100.00*	Common Shs Outst'g [E]	*100.00*
12.3	14.9	15.0	16.8	16.8	16.0	11.7	16.6	21.3	22.4	15.6	24.3	17.7	17.5	17.0	17.7	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*17.0*
.74	.99	.95	1.05	1.07	.90	.62	.84	1.12	1.13	.84	1.29	.91	.94	.98	1.02			Relative P/E Ratio	*.95*
3.3%	3.5%	3.7%	3.3%	3.4%	3.7%	3.5%	3.1%	2.9%	2.7%	2.6%	2.5%	3.5%	3.6%	3.4%	3.3%			Avg Ann'l Div'd Yield	*4.0%*
3738.1	2734.0	1880.9	2268.6	2915.1	2592.0	1953.7	2156.6	2906.0	1963.0	*2150*	*2200*	Revenues ($mill) [A]	*2500*
176.9	153.7	138.1	149.4	240.5	175.0	196.2	207.7	240.3	261.8	*280*	*290*	Net Profit ($mill)	*350*
30.2%	26.3%	15.5%	17.2%	--	--	NMF	10.3%	21.4%	15.8%	*22.0%*	*22.0%*	Income Tax Rate	*22.0%*
4.7%	5.6%	7.3%	6.6%	8.2%	6.7%	10.0%	9.6%	8.3%	13.3%	*13.0%*	*13.2%*	Net Profit Margin	*14.0%*
38.2%	43.2%	47.7%	44.6%	45.4%	49.8%	55.1%	57.0%	57.8%	58.2%	*57.5%*	*57.0%*	Long-Term Debt Ratio	*55.0%*
61.8%	56.8%	52.3%	55.4%	54.6%	50.2%	44.9%	43.0%	42.2%	41.8%	*42.5%*	*43.0%*	Common Equity Ratio	*45.0%*
1564.4	1950.6	2230.1	2233.7	2599.6	3088.9	4104.2	3793.0	4302.6	4758.8	*5250*	*5500*	Total Capital ($mill)	*6000*
1884.1	2128.3	2407.7	2609.7	2651.0	3041.2	3983.0	4213.5	4649.9	5022.1	*5150*	*5250*	Net Plant ($mill)	*5550*
12.1%	8.6%	6.9%	7.7%	10.1%	6.4%	5.6%	6.5%	5.6%	5.5%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
18.3%	13.9%	11.8%	12.1%	16.9%	11.3%	10.6%	12.7%	13.2%	13.2%	*12.5%*	*12.5%*	Return on Shr. Equity	*13.0%*
18.3%	13.9%	11.8%	12.1%	16.9%	11.3%	10.6%	12.7%	13.2%	13.2%	*12.5%*	*12.5%*	Return on Com Equity	*13.0%*
11.0%	7.0%	4.8%	5.0%	10.2%	4.6%	4.3%	5.6%	6.2%	5.6%	*5.0%*	*5.0%*	Retained to Com Eq	*5.5%*
40%	50%	60%	59%	40%	59%	60%	56%	53%	57.8%	*60%*	*60%*	All Div'ds to Net Prof	*56%*

CAPITAL STRUCTURE as of 12/31/23
Total Debt $3227.3 mill. Due in 5 Yrs $580 mill.
LT Debt $2739.0 mill. LT Interest $125 mill.
Incl. $9.3 mill. capitalized leases.
(Interest coverage: 3.3x)
Pension Assets-9/23 $405.0 mill.
Oblig. $493.7 mill.

Pfd Stock None

Common Stock 98,303,527 shs.
as of 2/2/24

MARKET CAP: $4.1 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2022	2023	12/31/23
Cash Assets	1.1	1.0	2.7
Other	755.0	531.1	675.3
Current Assets	756.1	532.1	678.0
Accts Payable	156.6	151.8	105.6
Debt Due	499.1	368.3	488.3
Other	448.5	286.5	368.1
Current Liab.	1104.2	806.6	962.0
Fix. Chg. Cov.	545%		

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-3.0%	-6.0%	*2.5%*
"Cash Flow"	7.0%	4.5%	*5.0%*
Earnings	5.0%	2.5%	*5.0%*
Dividends	6.5%	6.5%	*5.0%*
Book Value	7.5%	7.0%	*4.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) [A] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	454.3	802.2	367.6	532.5	2156.6
2022	675.8	912.3	552.3	765.5	2906.0
2023	723.6	644.0	264.1	331.3	1963.0
2024	467.2	*850*	*450*	*382.8*	*2150*
2025	*680*	*770*	*460*	*290*	*2200*

Fiscal Year Ends	EARNINGS PER SHARE [A B] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	.46	1.77	d.15	.07	2.16
2022	.69	1.36	d.04	.50	2.50
2023	1.14	1.16	.10	.30	2.70
2024	.74	*1.35*	*.05*	*.66*	*2.80*
2025	*.75*	*1.40*	*.05*	*.70*	*2.90*

Cal-endar	QUARTERLY DIVIDENDS PAID [C]■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.3125	.3125	.3125	.3325	1.27
2021	.3325	.3325	.3325	.3625	1.36
2022	.3625	.3625	.3625	.3625	1.45
2023	.39	.39	.39	.39	1.56
2024	.42				

BUSINESS: New Jersey Resources Corp. is a holding company providing retail/wholesale energy svcs. to customers in NJ, and in states from the Gulf Coast to New England, and Canada. New Jersey Natural Gas had 576,000 cust. at 9/30/23. Fiscal 2023 volume: 128 bill. cu. ft. (23% interruptible, 50% residential, commercial & firm transportation, 27% other). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2021 dep. rate: 2.8%. Has 1,350 empls. Off./dir. own less than 1% of common; BlackRock, 15.9%; Vanguard, 11.4% (12/23 Proxy). CEO, President & Director: Steven D. Westhoven. Incorporated: New Jersey. Address: 1415 Wyckoff Road, Wall, NJ 07719. Telephone: 732-938-1480. Web: www.njresources.com.

New Jersey Resources finished fiscal 2023 in good shape. (Fiscal years end September 30th.) Net financial earnings per share of $0.30 in the fiscal fourth quarter propelled the bottom line to $2.70 over the full year, an 8% advance. These metrics aligned exactly with our earlier forecasts; however, revenues were well below our targets due to falling natural gas prices, which are a cost that is largely passed through to customers directly. Notably, strong customer growth at the utility, expansion of Clean Energy Ventures, and the completion of the Adelphia Gateway Pipeline all contributed to the solid twelve-month performance.

Earnings were down to begin fiscal 2024. Share net landed at $0.74 in the December period, well short of our call for $1.10 and the year-earlier tally. Part of the reason for the particularly poor comparison is due to the effect of winter storm Elliot at the end of 2022, which boosted earnings by as much as $0.20 per share. As a result, the Energy Services segment in particular registered a $45 million decrease in net financial earnings, whereas the other segments combined for a $7 million increase, notably led by a $14 million improvement at Clean Energy Ventures.

The remainder of 2024 looks likely to generate growth. While we have left our profit target in place despite the first-quarter earnings miss, management has recently increased its guidance for fiscal 2024, now forecasting a range from $2.85 to $3.00 per share. Winter weather in January was the stated impetus for the increase, with Energy Services set to generate a boost from its Asset Management Agreements. Our forecast reflects earnings growth expectations of 4% this year, versus the target long-run average of 7% to 9% annual increases.

Our long-term outlook provides the basis for solid capital appreciation potential. New rates expected in fiscal 2025 should help deliver towards our targets. Meantime, the stock is ranked to underperform the broader market (Timeliness: 5, Lowest). Thus, patient investors may well find a more favorable entry point, from which to buy-and-hold, in the year ahead.

Earl B. Humes *February 23, 2024*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Qtly. revenues and egs. may not sum to total due to rounding and change in shares outstanding. Next earnings report due early May.
(C) Dividends historically paid in early Jan., April, July, and October. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2023: $585 million, $6.00/share.
(E) In millions, adjusted for 3/15 split.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	45
Earnings Predictability	60

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NISOURCE INC. NYSE-NI

RECENT PRICE 25.63 | P/E RATIO 15.4 (Trailing: 16.3 Median: 21.0) | RELATIVE P/E RATIO 0.89 | DIV'D YLD 4.0% | VALUE LINE

TIMELINESS 3 Lowered 12/29/23
SAFETY 2 Raised 2/23/24
TECHNICAL 3 Raised 2/23/24
BETA .90 (1.00 = Market)

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$23-$39 $31 (20%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+75%)	18%
Low	35	(+30%)	10%

Institutional Decisions

	1Q2023	2Q2023	3Q2023
to Buy	301	249	278
to Sell	201	256	234
Hld's(000)	387698	393166	394475

	High:	33.5	44.9	49.2	26.9	27.8	28.1	30.7	30.5	27.8	32.6	29.0	27.5
	Low:	24.8	32.1	16.0	19.0	21.7	22.4	24.7	19.6	21.1	23.8	22.9	24.8

LEGENDS
0.50 x Dividends p sh divided by Interest Rate
Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range 2027 2028 2029

% TOT. RETURN 1/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-2.9	3.7
3 yr.	30.3	20.4
5 yr.	11.7	63.1

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
	32.36	24.02	22.99	21.33	16.31	18.04	20.47	14.58	13.90	14.46	13.74	13.63	11.95	12.09	14.23	*14.45*	*14.60*	*15.05*	Revenues per sh	*16.10*
	3.32	2.96	3.19	2.98	3.13	3.41	3.60	2.27	2.71	2.07	2.86	3.17	3.15	3.26	3.47	*3.60*	*3.80*	*4.80*	"Cash Flow" per sh	*4.25*
	1.34	.84	1.06	1.05	1.37	1.57	1.67	.63	1.00	.39	1.30	1.31	1.32	1.37	1.47	*1.60*	*1.70*	*1.85*	Earnings per sh [A]	*2.10*
	.92	.92	.92	.92	.94	.98	1.02	.83	.64	.70	.78	.80	.84	.88	.94	1.00	*1.06*	*1.12*	Div'ds Decl'd per sh [B] ■	*1.20*
	3.54	2.81	2.88	3.99	4.83	5.99	6.42	4.26	4.57	5.03	4.88	4.72	4.49	4.53	6.32	*7.95*	*7.00*	*6.50*	Cap'l Spending per sh	*6.75*
	17.24	17.54	17.63	17.71	17.90	18.77	19.54	12.04	12.60	12.82	13.08	13.36	12.44	13.33	13.14	*19.45*	*20.00*	*20.50*	Book Value per sh [C]	*18.75*
	274.26	276.79	279.30	282.18	310.28	313.68	316.04	319.11	323.16	337.02	372.36	382.14	391.76	404.30	411.10	*415.00*	*425.00*	*435.00*	Common Shs Outst'g [D]	*450.00*
	12.1	14.3	15.3	19.4	17.9	18.9	22.7	37.3	23.2	NMF	19.3	21.3	18.7	18.0	19.6	*16.8*	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	*19.0*
	.73	.95	.97	1.22	1.14	1.06	1.19	1.88	1.22	NMF	1.04	1.13	.96	.99	11.8	*.97*			Relative P/E Ratio	*1.05*
	5.7%	7.6%	5.7%	4.5%	3.8%	3.3%	2.7%	3.5%	2.8%	2.8%	3.1%	2.9%	3.4%	3.6%	3.3%	3.7%			Avg Ann'l Div'd Yield	*3.0%*
							6470.6	4651.8	4492.5	4874.6	5114.5	5208.9	4681.7	4899.6	5850.6	*6000*	*6200*	*6550*	Revenues ($mill)	*7250*
							530.7	198.6	328.1	128.6	478.3	549.8	562.6	626.3	648.2	*665*	*725*	*805*	Net Profit ($mill)	*945*
							36.9%	41.6%	35.7%	71.0%	19.7%	17.0%	18.3%	15.7%	17.2%	*19.0%*	*19.0%*	*19.0%*	Income Tax Rate	*19.0%*
							--	--	--	--	--	--	--	2.0%	2.3%	*2.5%*	*2.5%*	*2.5%*	AFUDC % to Net Profit	*2.5%*
							56.9%	60.7%	59.8%	63.5%	55.3%	56.8%	61.6%	56.9%	55.7%	*57.5%*	*57.5%*	*57.5%*	Long-Term Debt Ratio	*55.0%*
							43.1%	39.3%	40.2%	36.5%	37.9%	36.9%	32.5%	33.5%	31.6%	*35.0%*	*35.0%*	*35.0%*	Common Equity Ratio	*37.5%*
							14331	9792.0	10129	11832	12856	13843	14972	16131	17099	*19000*	*20000*	*21000*	Total Capital ($mill)	*22500*
							16017	12112	13068	14360	15543	16912	16620	17882	19843	*22500*	*24500*	*25750*	Net Plant ($mill)	*28000*
							5.3%	4.0%	5.0%	2.6%	5.1%	5.3%	5.0%	4.9%	3.8%	*3.5%*	*3.5%*	*4.0%*	Return on Total Cap'l	*4.0%*
							8.6%	5.2%	8.1%	3.0%	8.3%	9.2%	9.8%	9.0%	9.3%	*8.0%*	*8.5%*	*9.0%*	Return on Shr. Equity	*9.5%*
							8.6%	5.2%	8.1%	3.0%	9.6%	9.7%	10.4%	10.6%	12.0%	*10.0%*	*10.5%*	*11.0%*	Return on Com Equity	*11.0%*
							3.4%	NMF	3.0%	NMF	4.0%	3.8%	3.8%	4.2%	4.0%	*3.5%*	*4.0%*	*4.5%*	Retained to Com Eq	*5.0%*
							61%	NMF	63%	NMF	60%	64%	67%	64%	64%	*63%*	*62%*	*60%*	All Div'ds to Net Prof	*57%*

CAPITAL STRUCTURE as of 9/30/23
Total Debt $13258.0 mill. Due in 5 Yrs $2355 mill.
LT Debt $11011.3 mill. LT Interest $368 mill.
(Interest cov. earned: 5.8x) (59% of Cap'l)

Leases, Uncapitalized Annual rentals $8.0 mill.
Pension Assets-12/22 $1.4 bill. Oblig. $1.4 bill.

Pfd Stock $1547 mill. Pfd Div'd $55.1 mill.

Common Stock 413,415,441 shs.
as of 10/24/23
MARKET CAP: $10.6 billion (Large Cap)

CURRENT POSITION ($MILL.)

	2021	2022	9/30/23
Cash Assets	85.2	40.8	56.0
Other	1835.6	2543.5	1759.4
Current Assets	1920.8	2584.3	1815.4
Accts Payable	697.8	899.5	648.2
Debt Due	618.1	1791.9	2246.7
Other	1430.3	1969.1	1500.5
Current Liab.	2746.2	4660.5	4395.4
Fix. Chg. Cov.	250%	255%	260%

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '27-'29
Revenues	-5.0%	-3.5%	*5.5%*
"Cash Flow"	.5%	6.5%	*5.5%*
Earnings	1.5%	15.0%	*9.5%*
Dividends	-.5%	3.5%	*4.5%*
Book Value	-3.0%	.5%	*5.0%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1545.6	986.0	959.4	1408.6	4899.6
2022	1873.3	1183.2	1089.5	1704.6	5850.6
2023	1966.0	1090.0	1027.4	*1916.6*	*6000*
2024	*2000*	*1125*	*1150*	*1925*	*6200*
2025	*2115*	*1190*	*1215*	*2030*	*6550*

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.77	.13	.11	.39	1.37
2022	.75	.12	.10	.50	1.47
2023	.77	.11	.19	*.53*	*1.60*
2024	*.85*	*.15*	*.13*	*.57*	*1.70*
2025	*.90*	*.20*	*.15*	*.60*	*1.85*

QUARTERLY DIVIDENDS PAID [B] ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.21	.21	.21	.21	.84
2021	.22	.22	.22	.22	.88
2022	.235	.235	.235	.235	.94
2023	.25	.25	.25	.25	1.00
2024	.265				

BUSINESS: NiSource Inc. is a holding company for Northern Indiana Public Service Company (NIPSCO), which supplies electricity and gas to the northern third of Indiana. Customers: 479,185 electric in Indiana, 3,200,000 gas in Indiana, Ohio, Pennsylvania, Kentucky, Virginia, Maryland, through its Columbia subsidiaries. Revenue breakdown, 2022: electrical, 31%; gas, 69%; other, less than 1%. Generating sources, coal, 69.4%; purchased & other, 30.6%. 2022 reported depreciation rates: 3.1% electric, 2.3% gas. Has 7,304 employees. Chairman: Richard L. Thompson. President & Chief Executive Officer: Lloyd Yates. Incorporated: Indiana. Address: 801 East 86th Avenue, Merrillville, Indiana 46410. Telephone: 877-647-5990. Internet: www.nisource.com.

NiSource's stock offers good value to risk-averse income investors. The natural gas and electric utility company's shares moved sideways in the three months since our November review, as the broader U.S. equity markets pushed on to record highs. Utilities have underperformed as bond yields and growth sectors have drawn investors' attention. Further, inflationary costs and higher interest rates (both of which we think are likely to decrease), have pressured growth, hurting this stock's performance. Yet, these shares have reached a compelling risk-adjusted valuation in comparison to others in the sector. Considering the ongoing transition to renewable energy and building of sustainable energy infrastructure, we see a lot of potential upside to buy-and-hold strategies.

Blackstone, Inc.'s recent acquisition of a non-controlling stake in NIPSCO, a NiSource subsidiary, points to the value here. Blackstone's infrastructure unit purchased 19.9% of the electric and gas subsidiary for $2.16 billion in January. The cash will aid the company's ambitious clean energy transition and decarbonization programs; NIPSCO is planning to phase out its coal-fired power plants by 2028, whereas this sourced 75% of power production as recently as 2018.

The significant investment required to reach its sustainability goals will be a key driver of growth. Capital investments amounting to $16 billion are planned over the next five years, contributing to an expected rate-base increase of 8% to 10% per year, and a 6% to 8% annual increase in earnings per share. Execution on regulatory approvals has been a key strength.

All told, we expect growth to continue at a moderate pace through the next three to five years. The utility likely ended 2023 in good form, and earnings per share probably grew roughly 9%. Note: The company was scheduled to report its annual results as we went to press with this Issue. We think earnings are likely to increase by about 7% per year on average, while dividends may grow by 5% annually.

This issue's Safety rank has risen a notch, to 2 (above average). Likewise, the risk-adjusted upside is attractive.

Earl B. Humes *February 23, 2024*

(A) Dil. EPS. Excl. gains (losses) on disc. ops.: '08, ($1.14); '15, (30¢); '18, ($1.48). Next egs. report due early May. Qtl'y egs. may not sum to total due to rounding.
(B) Div'ds historically paid in mid-Feb., May, Aug., Nov. ■ Div'd reinv. avail.
(C) Incl. intang in '22: $1485.9 million, $3.61/sh.
(D) In mill.
(E) Spun off Columbia Pipeline Group (7/15)

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	20
Earnings Predictability	60

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N.W. NATURAL NYSE-NWN

RECENT PRICE 36.62 | P/E RATIO 13.8 (Trailing: 13.3 Median: 24.0) | RELATIVE P/E RATIO 0.80 | DIV'D YLD 5.3% | VALUE LINE

TIMELINESS 3 Raised 12/8/23
SAFETY 2 Raised 2/23/24
TECHNICAL 3 Raised 2/23/24
BETA .85 (1.00 = Market)

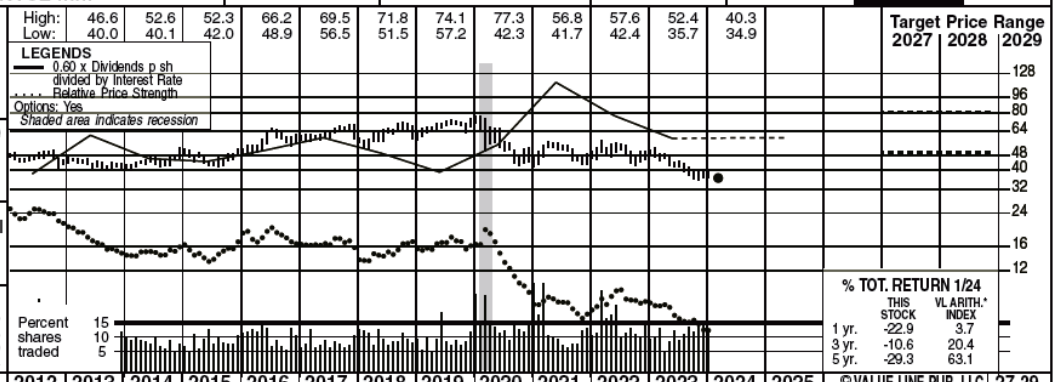
18-Month Target Price Range
Low-High Midpoint (% to Mid)
$33-$59 $46 (25%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+120%)	24%
Low	50	(+35%)	12%

Institutional Decisions

	1Q2023	2Q2023	3Q2023
to Buy	115	122	115
to Sell	102	123	110
Hld's(000)	26729	26926	27474



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
	39.16	38.17	30.56	31.72	27.14	28.02	27.64	26.39	23.61	26.52	24.45	24.49	25.29	27.64	29.20	*31.10*	*30.25*	*30.75*	Revenues per sh	*31.25*
	5.31	5.20	5.18	5.00	4.94	5.04	5.05	4.91	4.93	1.04	5.28	5.15	5.69	6.17	5.71	*5.85*	*6.15*	*6.85*	"Cash Flow" per sh	*7.55*
	2.57	2.83	2.73	2.39	2.22	2.24	2.16	1.96	2.12	d1.94	2.33	2.19	2.30	2.56	2.54	*2.65*	*2.75*	*3.00*	Earnings per sh A	*3.25*
	1.52	1.60	1.68	1.75	1.79	1.83	1.85	1.86	1.87	1.88	1.89	1.90	1.91	1.92	1.93	1.94	*1.95*	*1.96*	Div'ds Decl'd per sh B■	*1.98*
	3.92	5.09	9.35	3.76	4.91	5.13	4.40	4.37	4.87	7.43	7.43	7.95	9.18	9.49	9.53	*9.00*	*9.25*	*9.50*	Cap'l Spending per sh	*10.00*
	23.71	24.88	26.08	26.70	27.23	27.77	28.12	28.47	29.71	25.85	26.41	28.42	29.05	30.04	33.08	*31.70*	*39.70*	*40.55*	Book Value per sh D	*38.70*
	26.50	26.53	26.58	26.76	26.92	27.08	27.28	27.43	28.63	28.74	28.88	30.47	30.59	31.13	35.53	*37.00*	*38.00*	*39.00*	Common Shs Outst'g C	*42.00*
	18.1	15.2	17.0	19.0	21.1	19.4	20.7	23.7	26.9	- -	26.6	30.9	25.0	19.5	19.6	*16.3*	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	*20.0*
	1.09	1.01	1.08	1.19	1.34	1.09	1.09	1.19	1.41	- -	1.44	1.65	1.28	1.06	1.13	*.94*			Relative P/E Ratio	*1.10*
	3.3%	3.7%	3.6%	3.9%	3.8%	4.2%	4.1%	4.0%	3.3%	3.0%	3.0%	2.8%	3.3%	3.8%	3.9%	4.5%			Avg Ann'l Div'd Yield	*3.3%*
							754.0	723.8	676.0	762.2	706.1	746.4	773.7	860.4	1037.4	*1150*	*1150*	*1200*	Revenues ($mill)	*1250*
							58.7	53.7	58.9	d55.6	67.3	65.3	70.3	78.7	86.3	*98*	*105*	*115*	Net Profit ($mill)	*135*
							41.5%	40.0%	40.9%	- -	26.4%	16.2%	23.1%	25.8%	25.2%	*25.0%*	*25.0%*	*25.0%*	Income Tax Rate	*25.0%*
							7.8%	7.4%	8.7%	NMF	9.5%	8.8%	9.1%	9.1%	8.3%	*8.5%*	*9.1%*	*9.8%*	Net Profit Margin	*10.9%*
							44.8%	42.5%	44.4%	47.9%	48.1%	48.2%	49.2%	52.8%	51.5%	*54.0%*	*52.5%*	*52.5%*	Long-Term Debt Ratio	*50.0%*
							55.2%	57.5%	55.6%	52.1%	51.9%	51.8%	50.8%	47.2%	48.5%	*46.0%*	*47.5%*	*27.5%*	Common Equity Ratio	*50.0%*
							1389.0	1357.7	1529.8	1426.0	1468.9	1672.0	1748.8	1979.7	2421.6	*2550*	*2625*	*2750*	Total Capital ($mill)	*3250*
							2121.6	2182.7	2260.9	2255.0	2421.4	2438.9	2654.8	2871.4	3114.4	*3250*	*3400*	*3550*	Net Plant ($mill)	*3750*
							5.8%	5.5%	5.1%	NMF	5.8%	5.2%	5.2%	5.1%	3.6%	*4.0%*	*4.0%*	*4.5%*	Return on Total Cap'l	*4.0%*
							7.6%	6.9%	6.9%	NMF	8.8%	7.5%	7.9%	8.4%	7.3%	*7.5%*	*7.0%*	*7.5%*	Return on Shr. Equity	*8.5%*
							7.6%	6.9%	6.9%	NMF	8.8%	7.5%	7.9%	8.4%	7.3%	*7.5%*	*7.0%*	*7.5%*	Return on Com Equity	*8.5%*
							1.1%	.6%	.9%	NMF	2.1%	1.4%	1.7%	2.4%	2.1%	*2.0%*	*2.0%*	*3.0%*	Retained to Com Eq	*3.5%*
							85%	92%	87%	NMF	76%	82%	79%	71%	79%	*73%*	*70%*	*65%*	All Div'ds to Net Prof	*60%*

% TOT. RETURN 1/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-22.9	3.7
3 yr.	-10.6	20.4
5 yr.	-29.3	63.1

CAPITAL STRUCTURE as of 9/30/23
Total Debt $1686.3 mill. Due in 5 Yrs $713 mill.
LT Debt $1424.6 mill. LT Interest $75 mill.

(Total interest coverage: 1.9x)

Pension Assets-12/22 $300.0 mill.
Oblig. $413.4 mill.

Pfd Stock None

Common Stock 36,778,271 shares as of 10/26/23

MARKET CAP $1.3 billion (Small Cap)

CURRENT POSITION ($MILL.)	2021	2022	9/30/23
Cash Assets	18.6	29.3	156.6
Other	418.7	714.9	350.8
Current Assets	437.3	744.2	507.4
Accts Payable	133.5	180.7	99.3
Debt Due	389.8	348.9	261.7
Other	201.5	369.1	229.1
Current Liab.	724.8	898.7	590.1
Fix. Chg. Cov.	335%	320%	275%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '27-'29
Revenues	-2.5%	- -	*4.5%*
"Cash Flow"	1.0%	2.5%	*5.0%*
Earnings	-1.0%	2.5%	*6.5%*
Dividends	1.5%	.5%	*.5%*
Book Value	1.0%	.5%	*4.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	315.9	148.9	101.5	294.1	860.4
2022	350.3	195.0	116.8	375.3	1037.4
2023	462.4	237.9	141.5	*308.2*	*1150*
2024	*445*	*220*	*130*	*355*	*1150*
2025	*465*	*230*	*135*	*370*	*1200*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1.94	d.02	d.67	1.31	2.56
2022	1.80	.05	d.56	1.36	2.54
2023	2.01	.03	d.65	*1.26*	*2.65*
2024	*2.00*	*.05*	*d.65*	*1.35*	*2.75*
2025	*2.10*	*.05*	*d.60*	*1.45*	*3.00*

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.4775	.4775	.4775	.48	1.91
2021	.48	.48	.48	.483	1.92
2022	.483	.483	.483	.485	1.93
2023	.485	.485	.485	.488	1.94
2024	.488				

BUSINESS: Northwest Natural Holding Co. distributes natural gas to 1,000 communities, 795,000 customers, in Oregon (88% of customers) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 3.7 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system. Owns local underground storage. Rev. breakdown: residential, 37%; commercial, 22%; industrial, gas transportation, 41%. Employs 1,258. BlackRock Inc. owns 17.3% of shares; Vanguard, 12.2%; Off./Dir., .95% (4/23 proxy). CEO: David H. Anderson. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Tel.: 503-226-4211. Internet: www.nwnatural.com.

Northwest Natural stock offers good value for income-seeking accounts. The stock's price has fallen from highs of $77 a share in as few as four years, as the appeal of a steady income stream from utility companies has been overshadowed by the growth potential of other sectors and diminished by higher interest rates. Indeed, this sets the stage for what we believe is an attractive combination of stability and value. The stock's 5.3% dividend yield, well above the *Value Line* median, is a strong incentive which provides a solid foundation for future total return potential. While government bonds offer a similar value proposition with less risk, the idea that interest rates may well come down in the near future adds to the appeal of receiving this dividend. Furthermore, the current price-to-earnings ratio of 12.5 is notably low for the stock, and the the issue's Safety rank was recently raised a notch, to 2 (Above Average).

The company likely ended 2023 in good shape. Note: The company was scheduled to report its annual results shortly after we went to press with this Issue. Our conservative fourth-quarter outlook is influenced by mild El Nino year regional weather, and some inflationary pressure. Nonetheless, full-year share earnings likely rose a decent 4%, thanks largely to a strong first quarter. We expect earnings per share to advance anothe 4% in 2024, and 9% in 2025.

Resilient economic trends and sustainability initiatives underscore our earnings growth outlook. The company's service area ranks among the middle of the pack in economic and population growth trends, which contributes to our expectations for stability. The company's sustainability strategies are the main impetus for growth. Investments in this domain, including its expanding water business, and continual infrastructure hardening, should lead to rate-case execution and earnings increases ahead.

Risks are worth noting. Two key areas of concern are the possible banning of natural gas in new construction (a growing urban trend), and the increasing threat from wildfires in the region. Also, the stock's Earnings Predictability rank is quite low.

Earl B. Humes *February 23, 2024*

(A) Diluted earnings per share. Excludes nonrecurring items: '08, ($0.03); '09, $0.06; May not sum due to rounding. Next earnings report due in early May.

(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.
(C) In millions.

(D) Includes intangibles. In 2022: $149 million, $4.20/share.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	25
Earnings Predictability	15

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ONE GAS, INC. NYSE-OGS

RECENT PRICE 62.45 | P/E RATIO 15.2 (Trailing: 15.2, Median: NMF) | RELATIVE P/E RATIO 0.88 | DIV'D YLD 4.2% | VALUE LINE

TIMELINESS 3 Raised 12/8/23
SAFETY 2 New 6/2/17
TECHNICAL 4 Lowered 2/9/24
BETA .85 (1.00 = Market)

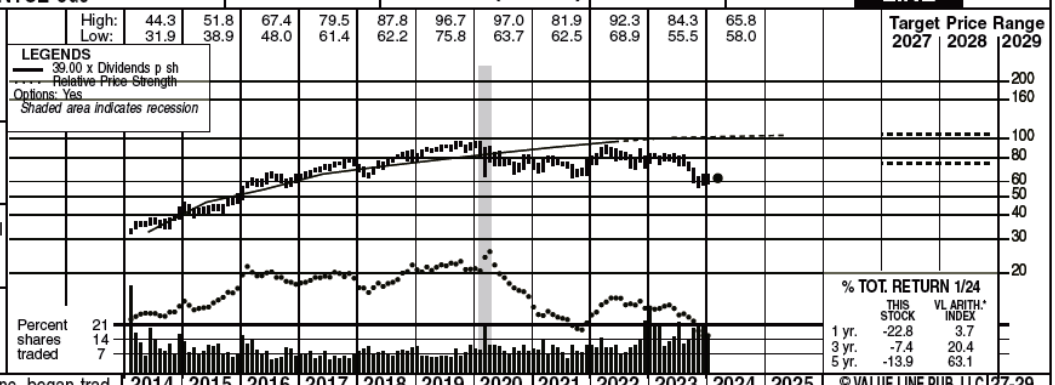
18-Month Target Price Range
Low-High Midpoint (% to Mid)
$52-$101 $77 (25%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+70%)	17%
Low	75	(+20%)	9%

Institutional Decisions

	1Q2023	2Q2023	3Q2023
to Buy	157	158	148
to Sell	133	133	153
Hld's(000)	51917	53044	51074



% TOT. RETURN 1/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-22.8	3.7
3 yr.	-7.4	20.4
5 yr.	-13.9	63.1

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
	34.92	29.62	27.30	29.43	31.08	31.32	28.78	33.72	46.58	*46.50*	*47.55*	*49.55*	Revenues per sh	*70.15*
	4.52	4.82	5.43	5.96	6.32	6.96	7.36	7.71	8.13	*9.10*	*9.85*	*10.90*	"Cash Flow" per sh	*13.95*
	2.07	2.24	2.65	3.02	3.25	3.51	3.68	3.85	4.08	*4.15*	*4.05*	*4.20*	Earnings per sh A	*5.00*
	.84	1.20	1.40	1.68	1.84	2.00	2.16	2.32	2.48	2.60	*2.64*	*2.68*	Div'ds Decl'd per sh B■	*2.85*
	5.70	5.63	5.91	6.81	7.50	7.91	8.87	9.23	11.01	*11.75*	*11.95*	*12.15*	Cap'l Spending per sh	*12.60*
	34.45	35.24	36.12	37.47	38.86	40.35	42.01	43.81	46.69	*47.05*	*49.55*	*54.50*	Book Value per sh	*60.20*
	52.08	52.26	52.28	52.31	52.57	52.77	53.17	53.63	55.35	*55.50*	*55.50*	*55.50*	Common Shs Outst'g C	*57.00*
	17.8	19.8	22.7	23.5	23.1	25.3	21.7	18.9	19.9	*17.9*	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*18.0*
	.94	1.00	1.19	1.18	1.25	1.35	1.11	1.02	1.16	*1.00*			Relative P/E Ratio	*1.00*
	2.3%	2.7%	2.3%	2.4%	2.5%	2.3%	2.7%	3.2%	3.1%	3.5%			Avg Ann'l Div'd Yield	*3.2%*
	1818.9	1547.7	1427.2	1539.6	1633.7	1652.7	1530.3	1808.6	2578.0	*2580*	*2640*	*2750*	Revenues ($mill)	*4000*
	109.8	119.0	140.1	159.9	172.2	186.7	196.4	206.4	221.7	*230*	*225*	*235*	Net Profit ($mill)	*285*
	38.4%	38.0%	37.8%	36.4%	23.7%	18.7%	17.5%	16.3%	17.3%	*15.5%*	*15.5%*	*16.0%*	Income Tax Rate	*20.0%*
	6.0%	7.7%	9.8%	10.4%	10.5%	11.3%	12.8%	11.4%	8.6%	*8.9%*	*8.5%*	*8.5%*	Net Profit Margin	*7.1%*
	40.1%	39.5%	38.7%	37.8%	38.6%	37.7%	41.5%	61.1%	50.7%	*42.0%*	*45.0%*	*45.0%*	Long-Term Debt Ratio	*51.0%*
	59.9%	60.5%	61.3%	62.2%	61.4%	62.3%	58.5%	38.9%	49.3%	*58.0%*	*55.0%*	*55.0%*	Common Equity Ratio	*49.0%*
	2995.3	3042.9	3080.7	3153.5	3328.1	3415.5	3815.7	6032.9	5246.2	*4500*	*5000*	*5500*	Total Capital ($mill)	*7000*
	3293.7	3511.9	3731.6	4007.6	4283.7	4565.2	4867.1	5190.8	5628.8	*6050*	*6425*	*6800*	Net Plant ($mill)	*8000*
	4.4%	4.7%	5.2%	5.8%	5.9%	6.4%	6.0%	3.9%	5.0%	*6.5%*	*6.0%*	*5.5%*	Return on Total Cap'l	*5.5%*
	6.1%	6.5%	7.4%	8.2%	8.4%	8.8%	8.8%	8.8%	8.6%	*9.0%*	*8.0%*	*8.0%*	Return on Shr. Equity	*8.5%*
	6.1%	6.5%	7.4%	8.2%	8.4%	8.8%	8.8%	8.8%	8.6%	*9.0%*	*8.0%*	*8.0%*	Return on Com Equity	*8.5%*
	3.7%	3.1%	3.5%	3.7%	3.7%	3.8%	3.7%	3.5%	3.4%	*3.5%*	*3.0%*	*3.0%*	Retained to Com Eq	*3.5%*
	40%	53%	52%	55%	56%	56%	58%	60%	60%	*63%*	*65%*	*63%*	All Div'ds to Net Prof	*57%*

The shares of ONE Gas, Inc. began trading "regular-way" on the New York Stock Exchange on February 3, 2014. That happened as a result of the separation of ONEOK's natural gas distribution operation. Regarding the details of the spinoff, on January 31, 2014, ONEOK distributed one share of OGS common stock for every four shares of ONEOK common stock held by ONEOK shareholders of record as of the close of business on January 21. It should be mentioned that ONEOK did not retain any ownership interest in the new company.

CAPITAL STRUCTURE as of 9/30/23
Total Debt $2990.0 mill. **Due in 5 Yrs** $1250.0 mill.
LT Debt $1862.6 mill. **LT Interest** $115.0 mill.
(LT interest earned: 4.5x; total interest coverage: 4.5x)
Leases, Uncapitalized Annual rentals $6.5 mill.
Pfd Stock None
Pension Assets-12/22 $950.8 mill.
Oblig. $953.0 mill.
Common Stock 55,454,050 shs.
as of 10/23/23
MARKET CAP: $3.5 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2021	2022	9/30/23
Cash Assets	8.9	9.7	9.2
Other	2215.7	1207.9	555.2
Current Assets	2224.6	1217.6	564.4
Accts Payable	258.6	360.5	168.6
Debt Due	494.0	572.7	1127.4
Other	227.9	256.2	275.7
Current Liab.	980.5	1189.4	1571.7
Fix. Chg. Cov.	625%	540%	550%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '27-'29
Revenues	- -	6.5%	*10.0%*
"Cash Flow"	- -	6.0%	*9.0%*
Earnings	- -	6.0%	*4.0%*
Dividends	- -	8.0%	*3.0%*
Book Value	- -	4.0%	*4.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	625.3	315.6	273.9	593.8	1808.6
2022	971.5	428.9	359.4	818.2	2578.0
2023	1032.1	398.1	335.8	*814*	*2580*
2024	*1040*	*415*	*360*	*825*	*2640*
2025	*1060*	*430*	*410*	*850*	*2750*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1.79	.56	.38	1.12	3.85
2022	1.83	.59	.44	1.23	4.08
2023	1.84	.58	.45	*1.28*	*4.15*
2024	*1.82*	*.57*	*.43*	*1.23*	*4.05*
2025	*1.87*	*.60*	*.48*	*1.25*	*4.20*

Calendar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.54	.54	.54	.54	2.16
2021	.58	.58	.58	.58	2.32
2022	.62	.62	.62	.62	2.48
2023	.65	.65	.65	.65	2.60
2024	.66				

BUSINESS: ONE Gas, Inc. provides natural gas distribution services to more than two million customers. There are three divisions: Oklahoma Natural Gas, Kansas Gas Service, and Texas Gas Service. The company purchased 165 Bcf of natural gas supply in 2022, compared to 164 Bcf in 2021. Total volumes delivered by customer (fiscal 2022): transportation, 57.3%; residential, 31.2%; commercial & industrial, 10.8%; other, .7%. ONE Gas has around 3,600 employees. BlackRock owns 12.6% of common stock; The Vanguard Group, 11.5%; State Street Corporation, 11.5%; officers and directors, 1.5% (4/23 Proxy). CEO: Robert S. McAnnally. Incorporated: Oklahoma. Address: 15 East Fifth Street, Tulsa, Oklahoma 74103. Telephone: 918-947-7000. Internet: www.onegas.com.

ONE Gas, Inc. probably had a lackluster performance in 2023. (Fourth-quarter numbers were not available when this report went to press.) Recall that during the first nine months, profits of $2.87 per share were only one cent higher than the previous year's $2.86 tally. This stemmed, to a certain degree, from a 12.5% increase in total operating expenses, which particularly reflected greater depreciation & amortization and operations & maintenance costs. Also, interest expense rose sharply. The number of diluted shares outstanding was somewhat higher, too. But the company's results were helped partly by new rates. Moreover, the effective income tax rate dropped. Nevertheless, it seems that full-year earnings per share were around $4.15. That would be quite close to 2022's $4.08 figure.

We anticipate another underwhelming showing in 2024. Although ONE Gas stands to enjoy the benefits of new rates and customer growth, they ought to be offset by heightened expenses (including employee-related and contractor costs, depreciation expense, and interest costs). So, the bottom line may only finish in the vicinity of $4.05 per share, modestly below our target for last year. But looking at 2025, a nearly 4% advance, to $4.20 a share, appears possible based to some extent on our assumption that the business climate is generally favorable.

The quarterly dividend was recently raised by a penny, to $0.66 a share. The company says that it plans to keep the average annual dividend growth rate between 1% and 2% through fiscal 2028. We believe that substantially slower increase, versus prior years, is partly because operating expenses should continue to climb as ONE Gas expands. In any event, the payout ratio out to the end of the decade ought to be manageable, in the 55% to 60% range.

There are some things to like about these shares. Capital gains potential over the 18-month span is significant. Upside possibilities during the 2027-2029 period are worthwhile, too. The solid dividend yield is another plus. Consider, also, the 2 (Above Average) Safety rank and high Price Stability mark of 90 out of 100.

Frederick L. Harris, III February 23, 2024

(A) Diluted EPS. Excludes nonrecurring gain: 2017, $0.06. Next earnings report due early May. Quarterly EPS figures for 2022 don't equal total due to rounding.

(B) Dividends historically paid in early March, June, Sept., and Dec. ■ Dividend reinvestment plan. Direct stock purchase plan.
(C) In millions.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	50
Earnings Predictability	100

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SOUTH JERSEY INDS. NYSE-SJI

RECENT PRICE 33.99 | P/E RATIO 19.4 (Trailing: 20.0 Median: 19.0) | RELATIVE P/E RATIO 1.20 | DIV'D YLD 3.7% | VALUE LINE

TIMELINESS — Suspended 3/11/22
SAFETY 3 Lowered 8/26/20
TECHNICAL — Suspended 3/11/22
BETA .90 (1.00 = Market)

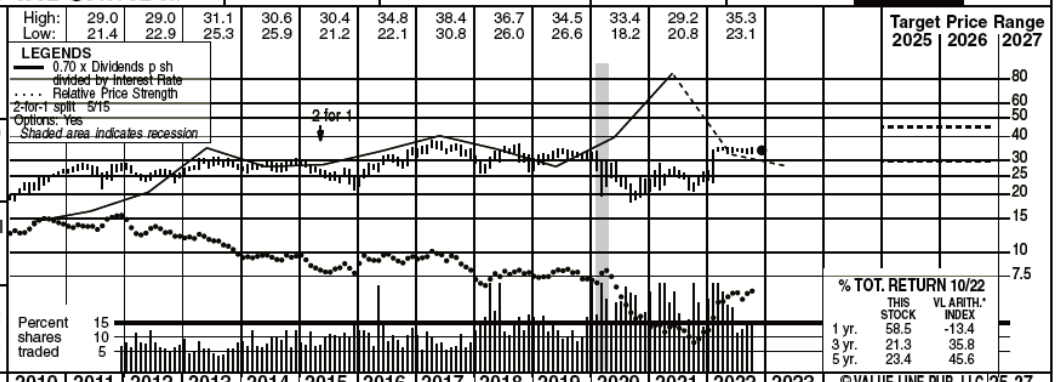
18-Month Target Price Range
Low-High Midpoint (% to Mid)
$15-$43 $29 (-15%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+30%)	10%
Low	30	(-10%)	1%

Institutional Decisions

	4Q2021	1Q2022	2Q2022
to Buy	135	171	151
to Sell	105	130	143
Hld's(000)	101881	102926	103244



% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	58.5	-13.4
3 yr.	21.3	35.8
5 yr.	23.4	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
15.88	16.15	16.18	14.19	15.48	13.71	11.16	11.18	12.98	13.52	13.04	15.63	19.20	17.63	15.32	16.98	*21.60*	*20.00*	Revenues per sh	*24.00*
1.75	1.60	1.74	1.86	2.10	2.23	2.34	2.48	2.67	2.42	2.67	2.79	2.91	2.56	3.32	3.32	*2.70*	*3.00*	"Cash Flow" per sh	*4.40*
1.23	1.05	1.14	1.19	1.35	1.45	1.52	1.52	1.57	1.44	1.34	1.23	1.38	1.12	1.68	1.62	*1.70*	*1.85*	Earnings per sh A	*2.40*
.46	.51	.56	.61	.68	.75	.83	.90	.96	1.02	1.06	1.10	1.13	1.16	1.19	1.22	*1.25*	*1.28*	Div'ds Decl'd per sh B ■	*1.50*
1.26	.94	1.04	1.83	2.79	3.20	4.01	4.84	5.01	4.87	3.50	3.43	3.99	5.46	4.84	4.53	*4.95*	*5.10*	Cap'l Spending per sh	*6.75*
7.55	8.12	8.67	9.12	9.54	10.33	11.63	12.64	13.65	14.62	16.22	14.99	14.82	15.41	16.51	16.95	*18.00*	*19.00*	Book Value per sh C	*22.00*
58.65	59.22	59.46	59.59	59.75	60.43	63.31	65.43	68.33	70.97	79.48	79.55	85.51	92.39	100.59	117.34	*125.00*	*125.00*	Common Shs Outst'g D	*125.00*
11.9	17.2	15.9	15.0	16.8	18.4	16.9	18.9	18.0	17.9	21.7	27.9	22.6	28.3	14.9	15.1	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*16.0*
.64	.91	.96	1.00	1.07	1.15	1.08	1.06	.95	.90	1.14	1.40	1.22	1.51	.77	.82			Relative P/E Ratio	*.90*
3.2%	2.8%	3.1%	3.4%	3.0%	2.8%	3.2%	3.1%	3.4%	3.9%	3.6%	3.2%	3.6%	3.7%	4.8%	5.0%			Avg Ann'l Div'd Yield	*3.5%*
						706.3	731.4	887.0	959.6	1036.5	1243.1	1641.3	1628.6	1541.4	1992.0	*2700*	*2500*	Revenues ($mill)	*3000*
						93.3	97.1	104.0	99.0	102.8	98.1	116.2	103.0	163.0	178.0	*215*	*230*	Net Profit ($mill)	*300*
						10.8%	--	--	5.9%	42.0%	--	--	--	9.9%	22.0%	*21.0%*	*21.0%*	Income Tax Rate	*21.0%*
						13.2%	13.3%	11.7%	10.3%	9.9%	7.9%	7.1%	6.3%	10.6%	8.9%	*8.0%*	*9.5%*	Net Profit Margin	*10.0%*
						45.0%	45.1%	48.0%	49.2%	38.5%	48.5%	62.4%	59.2%	62.6%	61.6%	*62.0%*	*60.0%*	Long-Term Debt Ratio	*60.0%*
						55.0%	54.9%	52.0%	50.8%	61.5%	51.5%	37.6%	40.8%	37.4%	38.4%	*38.0%*	*40.0%*	Common Equity Ratio	*40.0%*
						1337.6	1507.4	1791.9	2043.9	2097.2	2315.4	3373.9	3493.9	4437.3	5178.2	*5750*	*6250*	Total Capital ($mill)	*7000*
						1578.0	1859.1	2134.1	2448.1	2623.8	2700.2	3653.5	4073.5	4464.2	4912.3	*5400*	*5750*	Net Plant ($mill)	*6500*
						7.4%	6.8%	6.4%	5.4%	5.4%	5.1%	4.4%	4.0%	4.8%	4.6%	*3.5%*	*3.5%*	Return on Total Cap'l	*4.5%*
						12.7%	11.7%	11.2%	9.5%	8.0%	8.2%	9.2%	7.2%	9.8%	9.0%	*9.5%*	*9.5%*	Return on Shr. Equity	*10.5%*
						12.7%	11.7%	11.2%	9.5%	8.0%	8.2%	9.2%	7.2%	9.8%	9.0%	*9.5%*	*9.5%*	Return on Com Equity	*10.5%*
						5.8%	4.8%	4.3%	2.8%	1.6%	.9%	1.7%	NMF	2.9%	2.2%	*2.0%*	*3.0%*	Retained to Com Eq	*3.5%*
						55%	59%	61%	71%	80%	89%	82%	NMF	70%	75%	*75%*	*70%*	All Div'ds to Net Prof	*65%*

CAPITAL STRUCTURE as of 9/30/22
Total Debt $3801.1 mill. Due in 5 Yrs $278.5 mill.
LT Debt $3566.8 mill. LT Interest $150 mill.

Leases, Uncapitalized Annual rentals $1.1 mill.
Pension Assets-12/21 $331 mill.
Oblig. $351.6 mill.

Pfd Stock None

Common Stock 124,803,932 shs.
as of 11/1/22

MARKET CAP: $4.2 billion (Mid Cap)

CURRENT POSITION ($MILL.)

	2020	2021	9/30/22
Cash Assets	34.0	28.8	52.8
Other	472.8	610.2	711.6
Current Assets	506.8	639.0	764.4
Accts Payable	256.6	330.2	483.1
Debt Due	739.2	400.1	234.3
Other	167.8	225.4	369.2
Current Liab.	1163.6	955.7	1086.6
Fix. Chg. Cov.	238%	275%	260%

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	1.5%	5.0%	*4.5%*
"Cash Flow"	4.0%	3.5%	*5.5%*
Earnings	1.0%	.5%	*10.5%*
Dividends	6.0%	3.5%	*4.0%*
Book Value	5.5%	2.0%	*5.0%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	637.3	266.9	261.2	463.2	1628.6
2020	534.1	260.0	261.5	485.8	1541.4
2021	674.3	311.8	365.6	640.3	1992.0
2022	824.6	511.4	608.5	*755.5*	*2700*
2023	*875*	*475*	*525*	*625*	*2500*

EARNINGS PER SHARE A

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.09	d.13	d.30	.46	1.12
2020	1.15	d.01	d.06	.62	1.68
2021	1.19	.02	d.17	.58	1.62
2022	1.25	.05	d.18	*.58*	*1.70*
2023	*1.30*	*.05*	*d.10*	*.60*	*1.85*

QUARTERLY DIVIDENDS PAID B■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	--	.280	.280	.567	1.13
2019	--	.287	.287	.582	1.16
2020	--	.295	.295	.598	1.19
2021	--	.303	.303	.613	1.22
2022	--	.310	.310	.310	

BUSINESS: South Jersey Industries, Inc. is a holding company. The company distributes natural gas in New Jersey and Maryland. South Jersey Gas rev. mix '21: residential, 48%; commercial, 23%; cogen. and electric gen., 9%; industrial, 20%. Acq. Elizabethtown Gas and Elkton Gas, 7/18. Nonutil. oper. incl. South Jersey Energy, South Jersey Resources Group, South Jersey Exploration, Marina Energy, South Jersey Energy Service Plus, and SJI Midstream. Has about 1,173 empl. Off./dir. own less than 1% of common; BlackRock, 14.4%; State Street Corporation, 13.9%; The Vanguard Group, 10.8% (3/22 proxy). Pres. & CEO: Michael J. Renna. Chairman: Joseph M. Rigby. Inc.: NJ. Addr.: 1 South Jersey Plaza, Folsom, NJ 08037. Tel.: 609-561-9000. Web: www.sjindustries.com.

South Jersey Industries is moving ahead with plans to be acquired. On February 24th the company entered into a definitive agreement to be acquired by the private capital Infrastructure Investments Fund (IIF) for $36.00 per share in an all cash bid. Following the announcement, the stock spiked 40% and have since been trading between $32 and $36 per share.

There are a few concerns to note, regarding the proposed transaction. Although unlikely, it is possible for IIF to back out of the deal. This scenario would be disadvantageous at this time, with shares trading at a significant premium to the preannouncement levels. Should this occur, IIF would be penalized up to $255 million, roughly $2 per share, but prices would likely retreat to between $25 and $30. Another consideration is that the deal may take longer than expected to materialize as there are many regulatory hurdles to clear. Currently, we look to the fourth quarter for a resolution in the takeover. The shares are trading fairly close to the buyout price, suggesting the likelihood that the deal should go through as planned. However, conserative accounts may want to sell their shares on the open market on the small chance the transaction is blocked. Relevant regulatory bodies have been known to delay or even prohibit similar acquisitions, and could potentially impede the deal to shareholder's detriment. We deem both scenarios as unlikely, but they are of significant consequence.

South Jersey Industries performed well in the third quarter. The bottom line came in worse than we expected, with a share loss of $0.18 versus our forecast of a $0.12 deficit. Revenue growth was strong, however, at $608 million it was more than 65% higher than in the same quarter last year. Most of this gain came from non-utility revenues, which experienced an equal-sized increase in expenses, contributing to the lowly bottom-line. This should reverse in the winter months, as the groundwork laid by the expensive non-utility infrastructure business will likely bolster earnings in the next two quarters.

These shares are trading with a 5.6% spread on the takeover bid. Pending a close, dividends will continue being paid out at $0.31 per quarter.

Earl B. Humes *November 25, 2022*

(A) Based on economic egs. from 2007. GAAP EPS: '14, $1.46; '15, $1.52; '16, $1.56; '17, ($0.04); '18, $0.21; '19, $0.84; '20, $1.62; '21, $0.81; '22, $0.93. Excl. nonrecur. gain (loss): '12, ($0.03); '13, ($0.24); '14, ($0.11); '15, $0.08; '16, $0.22; '17, ($1.27); '18, ($1.17); '19, ($0.28); '20, ($0.06); '21, ($0.81); '22 (0.07) Totals may not sum due to rounding. Next egs. due late Februrary (B) Div'ds paid early April, July, Oct., and late Dec. ■ Div. reinvest. plan avail. (C) Incl. reg. assets. In 2021: $672.4 mill., $5.73 per shr. (D) In mill., adj. for split.

Company's Financial Strength	B++
Stock's Price Stability	55
Price Growth Persistence	15
Earnings Predictability	70

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SOUTHWEST GAS NYSE-SWX

RECENT PRICE 60.50 | P/E RATIO 15.4 (Trailing:NMF Median: 20.0) | RELATIVE P/E RATIO 0.89 | DIV'D YLD 4.1% | VALUE LINE

TIMELINESS — Suspended 11/17/23
SAFETY 2 Raised 2/23/24
TECHNICAL — Suspended 11/17/23
BETA .90 (1.00 = Market)

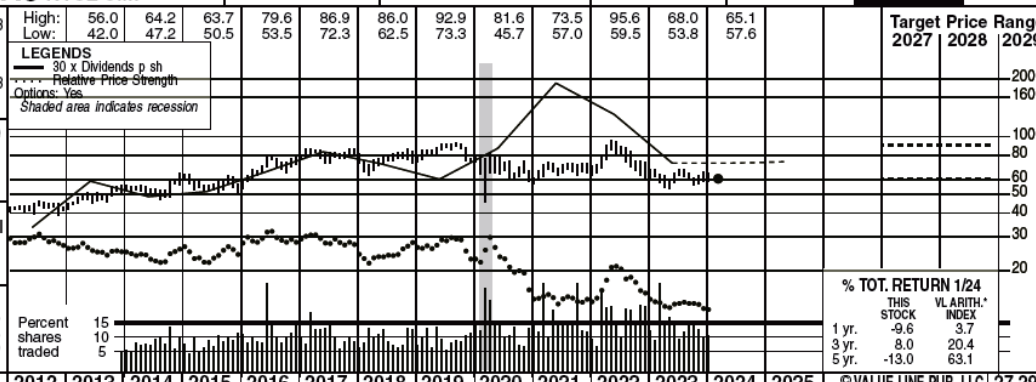
18-Month Target Price Range
Low-High Midpoint (% to Mid)
$50-$91 $71 (15%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	90	(+50%)	13%
Low	60	(Nil)	4%

Institutional Decisions

	1Q2023	2Q2023	3Q2023
to Buy	153	138	103
to Sell	124	136	140
Hld's(000)	65095	65230	64845



% TOT. RETURN 1/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-9.6	3.7
3 yr.	8.0	20.4
5 yr.	-13.0	63.1

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
	48.53	42.00	40.18	41.07	41.77	42.08	45.61	52.00	51.82	53.00	54.31	56.72	57.68	60.91	73.90	*73.60*	*71.60*	*72.00*	Revenues per sh	*70.95*
	5.76	6.16	6.46	6.81	7.73	8.24	8.47	8.62	9.29	8.83	8.14	9.40	9.87	9.46	3.91	*9.15*	*9.40*	*10.25*	"Cash Flow" per sh	*11.50*
	1.39	1.94	2.27	2.43	2.86	3.11	3.01	2.92	3.18	3.62	3.68	3.94	4.14	3.39	d3.10	*2.85*	*3.30*	*4.20*	Earnings per sh A	*4.25*
	.90	.95	1.00	1.06	1.18	1.32	1.46	1.62	1.80	1.98	2.08	2.18	2.28	2.38	2.48	2.48	*2.48*	*2.52*	Div'ds Decl'd per sh B■†	*2.60*
	6.79	4.81	4.73	8.29	8.57	7.86	8.53	10.30	11.15	12.97	14.44	17.06	14.43	11.84	12.80	*12.85*	*12.50*	*12.50*	Cap'l Spending per sh	*14.50*
	23.49	24.44	25.62	26.66	28.35	30.47	31.95	33.61	35.03	37.74	42.47	45.56	46.77	48.89	47.95	*50.00*	*52.50*	*52.90*	Book Value per sh	*55.50*
	44.19	45.09	45.56	45.96	46.15	46.36	46.52	47.38	47.48	48.09	53.03	55.01	57.19	60.42	67.12	*72.00*	*74.00*	*75.00*	Common Shs Outst'g C	*77.50*
	20.3	12.2	14.0	15.7	15.0	15.8	17.9	19.4	21.6	22.2	20.6	21.3	16.8	19.9	- -	*21.7*	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*18.0*
	1.22	.81	.89	.98	.95	.89	.94	.98	1.13	1.12	1.11	1.13	.86	1.08	- -	*1.25*			Relative P/E Ratio	*.90*
	3.2%	4.0%	3.2%	2.8%	2.8%	2.7%	2.7%	2.9%	2.6%	2.5%	2.7%	2.6%	3.3%	3.5%	3.2%	4.0%			Avg Ann'l Div'd Yield	*3.4%*
							2121.7	2463.6	2460.5	2548.8	2880.0	3119.9	3298.9	3680.5	4960.0	*5300*	*5300*	*5400*	Revenues ($mill)	*5500*
							141.1	138.3	152.0	173.8	182.3	213.9	232.3	200.8	d203.3	*205*	*245*	*315*	Net Profit ($mill)	*330*
							35.7%	36.4%	33.9%	32.8%	25.3%	20.5%	21.6%	16.1%	NMF	*21.0%*	*21.0%*	*21.0%*	Income Tax Rate	*21.0%*
							6.7%	5.6%	6.2%	6.8%	6.3%	6.9%	7.0%	5.5%	NMF	*3.9%*	*4.6%*	*5.8%*	Net Profit Margin	*6.0%*
							52.4%	49.3%	48.2%	49.8%	48.3%	47.9%	50.5%	58.2%	57.8%	*60.0%*	*58.0%*	*58.0%*	Long-Term Debt Ratio	*57.0%*
							47.6%	50.7%	51.8%	50.2%	51.7%	52.1%	49.5%	41.8%	42.2%	*40.0%*	*42.0%*	*42.0%*	Common Equity Ratio	*43.0%*
							3123.9	3143.5	3213.5	3613.3	4359.3	4806.4	5407.2	7069.5	7621.4	*9000*	*9250*	*9450*	Total Capital ($mill)	*10000*
							3658.4	3891.1	4132.0	4523.7	5093.2	5685.2	6176.1	7594.0	7024.5	*7450*	*7550*	*7750*	Net Plant ($mill)	*8000*
							5.7%	5.5%	5.8%	5.8%	5.2%	5.4%	5.3%	3.5%	NMF	*2.5%*	*2.5%*	*3.5%*	Return on Total Cap'l	*3.5%*
							9.5%	8.7%	9.1%	9.6%	8.1%	8.5%	8.7%	6.8%	NMF	*5.5%*	*6.5%*	*8.0%*	Return on Shr. Equity	*7.5%*
							9.5%	8.7%	9.1%	9.6%	8.1%	8.5%	8.7%	6.8%	NMF	*5.5%*	*6.5%*	*8.0%*	Return on Com Equity	*7.5%*
							5.0%	4.0%	4.1%	4.5%	3.6%	3.9%	4.0%	2.1%	NMF	*.5%*	*1.5%*	*3.0%*	Retained to Com Eq	*3.0%*
							47%	54%	55%	53%	55%	54%	54%	69%	NMF	*87%*	*75%*	*60%*	All Div'ds to Net Prof	*61%*

CAPITAL STRUCTURE as of 9/30/23
Total Debt $5335.3 mill. Due in 5 Yrs $1236 mill.
LT Debt $5235.5 mill. LT Interest $300 mill.
(Total interest coverage: 1.25x) (61% of Cap'l)

Leases, Uncapitalized Annual rentals $17.9 mill.
Pension Assets-12/22 $1068.5 mill. Oblig. $1224.9 mill.
Pfd Stock None

Common Stock 71,519,025 shs.
as of 11/31/23

MARKET CAP: $4.3 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2021	2022	9/30/23
Cash Assets	222.7	123.1	104.9
Other	1392.1	3584.6	1893.6
Current Assets	1614.8	3707.7	1998.5
Accts Payable	353.4	662.1	255.3
Debt Due	2206.3	1587.4	99.8
Other	552.3	1173.5	697.4
Current Liab.	3112.0	1173.5	1052.5
Fix. Chg. Cov.	310%	265%	145%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '27-'29
Revenues	3.5%	3.0%	*6.0%*
"Cash Flow"	4.0%	1.5%	*8.5%*
Earnings	5.5%	4.5%	*10.0%*
Dividends	8.5%	7.0%	*5.5%*
Book Value	6.5%	7.0%	*7.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	885.9	821.4	888.7	1084.5	3680.5
2022	1267.4	1146.1	1125.6	1420.9	4960.0
2023	1603.3	1293.6	1169.5	*1233.6*	*5300*
2024	*1425*	*1300*	*1220*	*1355*	*5300*
2025	*1445*	*1345*	*1280*	*1330*	*5400*

Calendar	EARNINGS PER SHARE A D Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	2.03	.43	d.19	1.15	3.39
2022	1.58	d.10	d.18	d4.18	d3.10
2023	.67	.40	.04	*1.74*	*2.85*
2024	*1.45*	*.55*	*.20*	*1.10*	*3.30*
2025	*1.75*	*.65*	*.15*	*1.65*	*4.20*

Calendar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.545	.570	.570	.570	2.26
2021	.570	.595	.595	.595	2.36
2022	.595	.62	.62	.62	2.46
2023	.62	.62	.62	.62	2.48
2024					

BUSINESS: Southwest Gas Holdings, Inc. is the parent holding company of Southwest Gas and Centuri Group. Southwest Gas is a regulated gas distributor serving 2.2 million customers in Arizona, Nevada, and California. Centuri provides construction services. 2022 margin mix: residential and small commercial, 85%; large commercial and industrial, 4%; transportation, 11%. Total throughput: 2.2 billion therms. Has 13,614 employees. Off. & dir. own .3% of common; BlackRock, 13.6%; Carl C. Icahn, 12.5%; The Vanguard Group, 9.7%; (3/23 Proxy). Chairman: Michael J. Melarkey. Pres. & CEO: Karen S. Haller. Inc.: DE. Addr.: 8360 S. Durango Drive, P.O. Box 98510 Las Vegas, Nevada 89193. Telephone: 702-876-7237. Internet: www.swgas.com.

Southwest Gas Holdings plans to pivot the spin-off of the Centuri Group. The company announced that it will pursue an initial public offering (IPO) for Centuri Holdings, Inc. versus earlier plans for a tax-free spin-off. Proceeds from the IPO will primarily be used to pay down the subsidiary's debt. Southwest Gas will continue to reduce its ownership interest thereafter. The offering is slated for the spring or summer of 2024, pending the replacement of the current Centuri CEO Paul Daily, after he announced plans for his retirement. The tax-free spin-off option is still available as a second resort. Note: Our forecasts do not account for pending deals until they are completed.

The company likely had a challenging year in 2023. (Southwest was scheduled to report its annual results shortly after we went to press with this Issue.) Although an improvement from a deficit in the year before, earnings in 2023 were likely well below the company's recent averages. A $71 million loss realized on the sale of MountainWest in the first quarter took a toll, along with a significant increase in interest costs. Some rate-base increases and gas purchase cost recoveries likely helped to partially offset these. Overall, net profits probably reached $205 million, which is about $25 million off Southwest's recent high in 2020, but also reflects slimmer margins and stagnant earnings growth. A rapid rate of share dilution made matters worse.

Earnings growth ought to recover over the intermediate term. Expectations for lower debt levels and interest payments, along with more efficient utility operations and tailwinds to the Centuri Group's infrastructure business should lead to a profit-growth recovery over the next two years. Too, we think ongoing changes in executive management and activism in the company's governance roles will likely put a priority on shareholder appeasement and accelerated earnings.

The stock's Timeliness rank remains suspended due to the pending corporate restructuring. While the planned IPO of Centuri Holdings should benefit Southwest Gas, our long-range projections for the company under its current configuration suggest limited upside for SWX.

Earl B. Humes *February 23, 2024*

(A) Diluted earnings. Excl. nonrec. gains (losses): '22, 10¢. Next egs. report due early May. (B) Dividends historically paid early March, June, September, and December.

■† Div'd reinvestment and stock purchase plan avail. (C) In millions. (D) Totals may not sum due to rounding.

Company's Financial Strength	A
Stock's Price Stability	80
Price Growth Persistence	30
Earnings Predictability	15

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SPIRE INC. NYSE-SR

RECENT PRICE 59.34 | P/E RATIO 14.5 (Trailing: 16.0) (Median: 19.0) | RELATIVE P/E RATIO 0.84 | DIV'D YLD 5.2% | VALUE LINE

TIMELINESS 3 Raised 2/16/24
SAFETY 2 Raised 6/20/03
TECHNICAL 4 Lowered 9/29/23
BETA .85 (1.00 = Market)

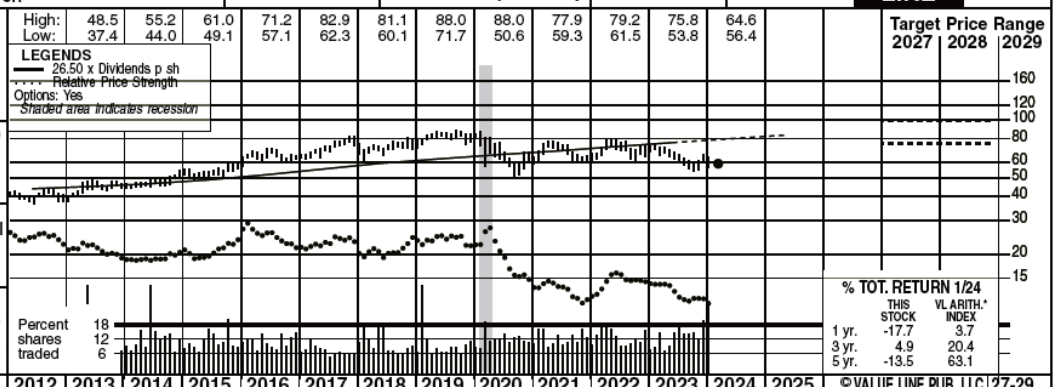
18-Month Target Price Range
Low-High Midpoint (% to Mid)
$50-$88 $69 (15%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	100	(+70%)	18%
Low	75	(+25%)	11%

Institutional Decisions

	1Q2023	2Q2023	3Q2023
to Buy	128	142	131
to Sell	132	138	144
Hld's(000)	45090	46098	48374



2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
100.44	85.49	77.83	71.48	49.90	31.10	37.68	45.59	33.68	36.07	38.78	38.30	35.96	43.24	41.88	50.12	*48.90*	*50.25*	Revenues per sh [A]	*57.25*
4.22	4.56	4.11	4.62	4.58	3.12	3.87	6.15	6.16	6.54	7.55	7.12	5.25	9.09	8.44	8.60	*9.05*	*9.65*	"Cash Flow" per sh	*11.00*
2.64	2.92	2.43	2.86	2.79	2.02	2.35	3.16	3.24	3.43	4.33	3.52	1.44	4.96	3.95	3.85	*4.10*	*4.50*	Earnings per sh [A B]	*5.50*
1.49	1.53	1.57	1.61	1.66	1.70	1.76	1.84	1.96	2.10	2.25	2.37	2.49	2.60	2.74	2.88	*3.02*	*3.16*	Div'ds Decl'd per sh [C ■]	*3.60*
2.57	2.36	2.56	3.02	4.83	4.00	3.96	6.68	6.42	9.08	9.86	16.15	12.37	12.09	10.52	12.45	*13.80*	*14.15*	Cap'l Spending per sh	*14.50*
22.12	23.32	24.02	25.56	26.67	32.00	34.93	36.30	38.73	41.26	44.51	45.14	44.19	46.74	49.08	50.29	*55.45*	*59.20*	Book Value per sh [D]	*66.05*
21.99	22.17	22.29	22.43	22.55	32.70	43.18	43.36	45.65	48.26	50.67	50.97	51.60	51.70	52.50	53.20	*55.50*	*56.50*	Common Shs Outst'g [E]	*62.00*
14.3	13.4	13.7	13.0	14.5	21.3	19.8	16.5	19.6	19.8	16.7	22.8	51.1	13.6	17.5	17.3	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*16.0*
.86	.89	.87	.82	.92	1.20	1.04	.83	1.03	1.00	.90	1.21	2.62	.73	1.01	1.00			Relative P/E Ratio	*.90*
3.9%	3.9%	4.7%	4.3%	4.1%	4.0%	3.8%	3.5%	3.1%	3.1%	3.1%	3.0%	3.4%	3.8%	4.0%	4.3%			Avg Ann'l Div'd Yield	*4.1%*
1627.2	1976.4	1537.3	1740.7	1965.0	1952.4	1855.4	2235.5	2198.5	2666.3	*2715*	*2840*	Revenues ($mill) [A]	*3550*
84.6	136.9	144.2	161.6	214.2	184.6	88.6	271.7	220.8	217.5	*230*	*255*	Net Profit ($mill)	*340*
27.6%	31.2%	32.5%	32.4%	--	15.7%	12.3%	20.1%	21.1%	15.1%	*18.0%*	*19.0%*	Income Tax Rate	*24.0%*
5.2%	6.9%	9.4%	9.3%	10.9%	9.5%	4.8%	12.2%	10.0%	8.2%	*8.5%*	*9.0%*	Net Profit Margin	*9.6%*
55.1%	53.0%	50.9%	50.0%	45.7%	45.0%	49.0%	52.5%	51.2%	54.9%	*52.0%*	*52.0%*	Long-Term Debt Ratio	*51.0%*
44.9%	47.0%	49.1%	50.0%	54.3%	49.7%	46.1%	43.2%	44.6%	41.3%	*44.0%*	*44.0%*	Common Equity Ratio	*45.0%*
3359.4	3345.1	3601.9	3986.3	4155.5	4625.6	4946.0	5597.3	5777.0	6471.3	*7000*	*7600*	Total Capital ($mill)	*9100*
2759.7	2941.2	3300.9	3665.2	3970.5	4352.0	4680.1	5055.7	5370.4	5778.9	*6150*	*6530*	Net Plant ($mill)	*7675*
3.1%	5.1%	4.9%	5.0%	6.3%	5.1%	2.9%	5.8%	4.9%	4.8%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.5%*
5.6%	8.7%	8.2%	8.1%	9.5%	7.3%	3.5%	10.2%	7.8%	7.5%	*7.5%*	*7.5%*	Return on Shr. Equity	*8.5%*
5.6%	8.7%	8.2%	8.1%	9.5%	7.9%	3.2%	10.6%	8.0%	7.6%	*7.5%*	*7.5%*	Return on Com Equity	*8.5%*
1.5%	3.7%	3.3%	3.3%	4.7%	2.7%	NMF	5.1%	2.5%	1.9%	*1.5%*	*2.0%*	Retained to Com Eq	*2.5%*
73%	58%	59%	60%	51%	66%	NMF	54%	71%	76%	*79%*	*76%*	All Div'ds to Net Prof	*70%*

CAPITAL STRUCTURE as of 12/31/23
Total Debt $4752.3 mill. **Due in 5 Yrs** $2310.0 mill.
LT Debt $3247.8 mill. **LT Interest** $140.0 mill.
(Total interest coverage: 2.4x)

Leases, Uncapitalized Annual rentals $9.8 mill.
Pension Assets-9/23 $630.3 mill.
Oblig. $832.5 mill.
Pfd Stock $242.0 mill. **Pfd Div'd** $14.8 mill.
Common Stock 54,983,397 shs.
as of 1/29/24

MARKET CAP: $3.3 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2022	2023	12/31/23
Cash Assets	6.5	5.6	4.8
Other	1585.5	1071.3	1215.1
Current Assets	1592.0	1076.9	1219.9
Accts Payable	617.4	253.1	293.8
Debt Due	1318.7	1112.1	1504.5
Other	417.5	390.2	412.2
Current Liab.	2353.6	1755.4	2210.5
Fix. Chg. Cov.	393%	294%	310%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-1.0%	4.5%	*4.0%*
"Cash Flow"	8.0%	5.0%	*4.0%*
Earnings	5.0%	3.0%	*4.5%*
Dividends	5.0%	5.5%	*4.5%*
Book Value	5.5%	3.5%	*5.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) [A] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	512.6	1104.9	327.8	290.2	2235.5
2022	555.4	880.9	448.0	314.2	2198.5
2023	814.0	1123.4	418.5	310.4	2666.3
2024	756.6	*1170*	*453.4*	*335*	*2715*
2025	*790*	*1235*	*465*	*350*	*2840*

Fiscal Year Ends	EARNINGS PER SHARE [A B F] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	1.65	3.55	.03	d.26	4.96
2022	1.01	3.27	d.10	d.20	3.95
2023	1.66	3.33	d.48	d.66	3.85
2024	1.52	*3.34*	*d.30*	*d.46*	*4.10*
2025	*1.50*	*3.35*	*d.11*	*d.24*	*4.50*

Calendar	QUARTERLY DIVIDENDS PAID [C ■] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.6225	.6225	.6225	.6225	2.49
2021	.65	.65	.65	.65	2.60
2022	.685	.685	.685	.685	2.74
2023	.72	.72	.72	.72	2.88
2024	.755				

BUSINESS: Spire Inc., formerly known as the Laclede Group, Inc., is a holding company for natural gas utilities, which distributes natural gas across Missouri, including the cities of St. Louis and Kansas City, Alabama, and Mississippi. Has roughly 1.7 million customers. Acquired Missouri Gas 9/13, Alabama Gas Co 9/14. Utility therms sold and transported in fiscal 2023: 3.2 bill. Revenue mix for regulated operations: residential, 67%; commercial and industrial, 25%; transportation, 5%; other, 3%. Officers and directors own 2.9% of common shares; American Century Companies, 15.4% (12/23 proxy). Chairman: Edward Glotzbach; CEO: Steve Lindsey. Inc.: Missouri. Address: 700 Market Street, St. Louis, Missouri 63101. Tel.: 314-342-0500. Internet: www.spireenergy.com.

Spire began fiscal 2024 (ends September 30th) on a sour note. First-quarter earnings per share slipped 8.4%, to $1.52, versus last year's $1.66 total. This was due partly to the fact that, for both the Gas Marketing and Midstream divisions, fiscal 2023's very favorable market conditions were not repeated. But on the plus side, the Gas Utility unit had a better performance, supported by the benefit of new rates. We do anticipate unspectacular consolidated results for the second quarter. Still, since the company faces easier bottom-line comparisons during the second half, full-year share net stands to grow roughly 6%, to $4.10, relative to the fiscal 2023 figure of $3.85. Regarding next year, profits stand to advance around 10%, to $4.50 a share, as operating margins expand further.

Capital expenditures for this fiscal year are expected to be around $765 million. (That's 15.5% higher than the fiscal 2023 level of $662.5 million.) Funds are being deployed to such areas as infrastructure upgrades at the utilities and new business development initiatives. Management adds that it looks for total spending from fiscal 2024 through fiscal 2033 to be $7.2 billion. Assuming that the balance sheet stays in healthy condition, Spire ought to have little trouble accomplishing these objectives.

Business prospects out to 2027-2029 appear decent. The gas utilities boast 1.7 million customers in Mississippi, Alabama, and Missouri. Too, the other operations, particularly pipelines, hold promise. Additional expansionary projects and technological enhancements in customer service and elsewhere should help Spire, as well. Finally, acquisitions are plausible, given the adequate finances. To that end, the company just completed the purchase of the MoGas and Omega pipeline systems (both serving customers in Missouri) from CorEnergy Infrastructure Trust, Inc. for $177.6 million.

What about the stock? Its dividend yield compares nicely to those of other equities in *Value Line's* Natural Gas Utility Industry. Moreover, capital gains potential over the 18-month span and out to 2027-2029 looks decent. Meanwhile, the Timeliness rank sits at 3 (Average).

Frederick L. Harris, III February 23, 2024

(A) Fiscal year ends Sept. 30th. (B) Based on diluted shares outstanding. Excludes gain from discontinued operations: '08, 94¢. Next earnings report due late April. (C) Dividends paid in early January, April, July, and October. ■ Dividend reinvestment plan available. (D) Incl. deferred charges. In '23: $1,171.6 mill., $22.02/sh. (E) In millions. (F) Qtly. egs. may not sum due to rounding or change in shares outstanding.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	35
Earnings Predictability	45

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Docket No: UG 490 Staff/108 Muldoon/11

UGI CORP. NYSE-UGI

RECENT PRICE 24.00 | P/E RATIO 8.3 (Trailing: 8.3 Median: 17.0) | RELATIVE P/E RATIO 0.48 | DIV'D YLD 6.3% | VALUE LINE

TIMELINESS 1 Raised 12/1/23
SAFETY 3 Lowered 5/26/23
TECHNICAL 3 Raised 2/23/24
BETA 1.10 (1.00 = Market)

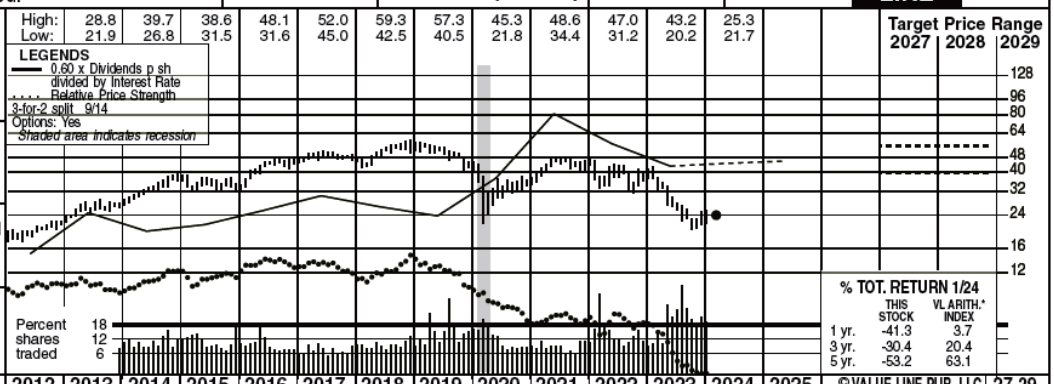
18-Month Target Price Range
Low-High Midpoint (% to Mid)
$20-$50 $35 (45%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+130%)	26%
Low	40	(+65%)	18%

Institutional Decisions

	1Q2023	2Q2023	3Q2023
to Buy	242	228	208
to Sell	233	263	246
Hld's(000)	172249	170969	169036



2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
41.27	35.25	34.01	36.31	38.56	42.10	47.92	38.65	32.84	35.18	43.94	35.03	31.31	35.49	48.00	42.33	*40.75*	*42.65*	Revenues per sh A	*44.80*
2.48	2.82	2.87	2.75	3.05	3.75	4.05	4.20	4.39	4.73	5.40	4.12	4.99	5.26	5.43	5.43	*5.60*	*5.75*	"Cash Flow" per sh	*6.00*
1.33	1.57	1.59	1.37	1.17	1.59	1.92	2.01	2.05	2.29	2.74	2.28	2.67	2.96	2.90	2.84	*2.90*	*3.00*	Earnings per sh AB	*3.15*
.50	.52	.60	.68	.71	.74	.79	.89	.93	.96	1.02	1.15	1.31	1.35	1.41	1.47	*1.52*	*1.56*	Div'ds Decl'd per sh C ■	*1.68*
1.44	1.85	2.11	2.15	2.01	2.84	2.64	2.83	3.26	3.67	3.30	3.37	3.13	3.29	3.82	4.62	*4.50*	*4.65*	Cap'l Spending per sh	*5.00*
8.80	9.78	11.10	11.79	13.21	14.59	15.39	15.55	16.46	18.18	21.14	18.27	19.70	25.27	27.76	20.00	*21.25*	*22.20*	Book Value per sh D	*23.60*
161.09	162.78	164.38	167.75	169.06	170.88	172.73	173.12	173.15	173.99	174.14	209.01	209.51	209.84	210.56	210.91	*211.00*	*211.00*	Common Shs Outst'g E	*212.00*
13.3	10.3	10.9	15.0	16.4	15.4	15.8	17.7	19.3	20.8	17.8	23.4	13.8	13.9	14.1	11.4	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*15.0*
.80	.69	.69	.94	1.04	.87	.83	.89	1.01	1.05	.96	1.25	.71	.75	.81	.66			Relative P/E Ratio	*.85*
2.9%	3.2%	3.5%	3.3%	3.7%	3.0%	2.6%	2.5%	2.3%	2.0%	2.1%	2.2%	3.6%	3.3%	3.5%	4.5%			Avg Ann'l Div'd Yield	*3.4%*
8277.3	6691.1	5685.7	6120.7	7651.2	7320.4	6559.0	7447.0	10106	8928	*8600*	*9000*	Revenues ($mill) A	*9500*
337.2	353.8	360.0	406.5	485.6	412.9	561.0	629.0	626.0	613.0	*630*	*660*	Net Profit ($mill)	*670*
30.6%	30.0%	31.4%	26.5%	--	16.6%	19.4%	45.4%	24.9%	NMF	*22.5%*	*22.0%*	Income Tax Rate	*22.0%*
4.1%	5.3%	6.3%	6.6%	6.3%	5.6%	8.6%	8.4%	6.2%	6.9%	*7.3%*	*7.3%*	Net Profit Margin	*7.0%*
56.4%	56.1%	56.9%	55.8%	53.0%	60.2%	59.2%	53.4%	51.7%	59.9%	*60.0%*	*60.0%*	Long-Term Debt Ratio	*60.0%*
43.6%	43.9%	43.1%	44.2%	47.0%	39.8%	40.8%	44.7%	46.6%	38.6%	*39.0%*	*39.0%*	Common Equity Ratio	*40.0%*
6092.7	6133.8	6616.9	7157.9	7827.9	9597.4	10109	11861	12549	10937	*11500*	*12000*	Total Capital ($mill)	*12500*
4543.7	4994.1	5238.0	5537.0	5808.2	6687.8	6960.0	7558.0	8040.0	8547.0	*8750*	*9000*	Net Plant ($mill)	*9750*
7.5%	7.7%	7.2%	7.2%	7.7%	5.6%	7.1%	6.6%	6.3%	5.6%	*5.5%*	*5.5%*	Return on Total Cap'l	*5.5%*
12.7%	13.1%	12.6%	12.9%	13.2%	10.8%	13.6%	11.4%	10.3%	14.0%	*13.5%*	*13.5%*	Return on Shr. Equity	*12.5%*
12.7%	13.1%	12.6%	12.9%	13.2%	10.8%	13.6%	11.4%	10.7%	14.5%	*14.0%*	*14.0%*	Return on Com Equity	*13.5%*
7.6%	7.4%	7.0%	7.5%	8.4%	5.6%	7.0%	6.0%	5.6%	6.8%	*6.5%*	*6.5%*	Retained to Com Eq	*6.0%*
40%	43%	45%	42%	36%	48%	49%	45%	47%	52%	*52%*	*52%*	All Div'ds to Net Prof	*53%*

CAPITAL STRUCTURE as of 12/31/23
Total Debt $7190 mill. Due in 5 Yrs $4176 mill.
LT Debt $6579 mill. LT Interest $375 mill.
(Total interest coverage: 4.0x) (60% of Cap'l)

Leases, Uncapitalized Annual rentals $104 mill.
Pension Assets-9/22 $556 mill. Oblig. $623 mill.

Pfd. Stock $167.0 mill. Pfd. Div'd. $20.25 (1% of Capital)
Common Stock 209,551,431 shares as of 1/26/24

MARKET CAP: $5.0 bill. (Mid-Cap)

CURRENT POSITION ($MILL.)	2022	2023	12/31/23
Cash Assets	405	340	302
Other	3397	1705	1983
Current Assets	3802	2045	2285
Accts Payable	891	613	741
Debt Due	517	706	611
Other	1036	955	989
Current Liab.	2444	2274	2341
Fix. Chg. Cov.	450%	465%	500%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-1.0%	-1.0%	*6.0%*
"Cash Flow"	5.0%	1.5%	*5.0%*
Earnings	8.0%	4.5%	*6.5%*
Dividends	6.5%	7.0%	*3.5%*
Book Value	6.5%	6.5%	*9.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	1932	2581	1496	1438	7447
2022	2673	3466	2033	1934	10106
2023	2759	3106	1659	1404	8928
2024	2121	*3000*	*1700*	*1779*	*8600*
2025	*2750*	*3000*	*1550*	*1700*	*9000*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	1.18	1.99	.13	d.33	2.96
2022	.93	1.91	.06	--	2.90
2023	1.14	1.68	--	.02	2.84
2024	1.20	*1.65*	*.05*	*Nil*	*2.90*
2025	*1.25*	*1.75*	*.05*	*d.05*	*3.00*

Calendar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.325	.325	.33	.33	1.31
2021	.33	.33	.345	.345	1.35
2022	.345	.345	.36	.36	1.41
2023	.36	.36	.375	.375	1.47
2024	.375				

BUSINESS: UGI Corp. operates six business segments: AmeriGas Propane (accounted for 11.6% of net income in 2023), UGI International (28.1%), Gas Utility (35.7%), Midstream & Marketing (31.5%), and Corp. & Other (NMF). UGI Utilities distributes natural gas and electricity to over 672,000 customers mainly in Pennsylvania; wholly-owned AmeriGas Ptrs. is the largest U.S. propane marketer, serving about 1.5 million users in 50 states. Acquired remaining 80% interest in Antargaz (3/04); Energy Transfer Partners (1/12). Vanguard Group owns 12.5% of stock; BlackRock, 12.8%; Officers/directors, 1.2% (12/23 proxy). Has 10,000 empls. President & CEO: John L. Walsh. Inc.: PA. Address: 460 N. Gulph Rd., King of Prussia, PA 19406. Tel.: 610-337-1000. Internet: www.ugicorp.com.

Despite the stock slumping, earnings at UGI Corp. held up in fiscal 2023, through a challenging environment for utilities. (Fiscal years end September 30th.) The diversified natural gas company's stock fared much worse than its peers throughout 2023, losing 33% of its value over the twelve-month stretch. However, operating performance held up relatively well in a difficult environment characterized by cost inflation, higher interest rates, turbulent global energy markets, and unusually warm weather. Revenues declined roughly 12%, with all segments other than the regulated utility showing attrition. The adjusted net income of $613 million was fairly resilient, declining only 2% in comparison. The company recorded a few notable one-time charges - a $660 million goodwill impairment to AmeriGas and a $181 million cost related to the exit of the UGI International energy marketing business - which are not included in our adjusted earnings metric.

Our near-term expectations are for uneven sales and steady earnings growth. Indeed, earnings in the fiscal 2024 first quarter were spot on with our target, albeit the top line has slipped since the figure fell far short of our estimate. We are now expecting a dip in revenues over the next two years. Lower liquid propane gas volume trends persist, and the exit of the energy marketing business continues to offset top-line gains in other segments. However, recent investments and acquisitions in the natural gas businesses, and success in rate cases from the utility, are likely enough to start driving an earnings-growth recovery.

Over a multi-year outlook, current strategic initiatives are likely to contribute to financial improvements. Initially, management aims to further align its natural gas businesses to leverage efficiencies and drive cost savings. This should then support liquidity while attempting to delever, with a hefty $1.7 billion of long-term debt coming due in 2025.

Wide recovery potential makes this a compelling choice for risk-tolerant investors seeking a sizable dividend yield (6.3%). The stock offers well-above-average total return potential on a long-term basis, along with some risk.

Earl B. Humes *February 23, 2024*

(A) Fiscal year ends Sept. 30. Quarterly sales and earnings may not sum to total due to rounding and/or change in share count. (B) Diluted earnings. Excludes nonrecur. gains/(losses): '15, (41¢); '16, 3¢; '17, 17¢; '18, $1.32; '21, $3.96. Next egs. report due early May. (C) Dividends historically paid in early Jan., April, July, and Oct. ■ Div. reinvest. plan available. (D) Incl. intang. At 9/23: $3,470 mill., $16.45/sh. (E) In mill., adjusted for stock split.

Company's Financial Strength	B++
Stock's Price Stability	70
Price Growth Persistence	25
Earnings Predictability	90

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The Water Utility Industry consists of six investor-owned companies that provide water services to residential, commercial, and industrial customers. It is a niche sector because most of the water utilities in the United States are run by states and local governments that do not issue stock.

In our last Industry report three months ago, we discussed how long-term interest rates had spiked higher. In retrospect, it was close to the peak yield on longer-duration Treasury bonds, which have declined sharply since the latter part of October.

The water infrastructure in the United States remains in subpar condition despite increased investment in this sector over the past decade or so.

Every water company we cover is in the midst of a large construction program. Many pipelines are corroding or leaking, and they need to be replaced.

Since the Industry is spending heavily on capital expenditures, the typical balance sheet in the this space is overleveraged.

The Water Utility Industry is very small. There are only six companies with a combined market capitalization of about $45 billion.

Shares of these stocks have performed very poorly in the recent past. Indeed, the Water Utility Industry is ranked among the lowest of the 93 industries followed by *Value Line*.

INDUSTRY TIMELINESS: 91 (of 93)

A Reversal In Long-Term Interest Rates

All types of utilities are often viewed as income equities due to their combination of high dividend yields and better-than-average distribution growth prospects. The yields on most water stocks are currently very close to the *Value Line* median, however. Indeed, *Essential Utilities's* 3.4% yield is the one exception in the group. In any case, as heavy borrowers of debt, lower interest rates ought to be beneficial to the Industry. On October 18th, the yield on the benchmark 10-year Treasury bond eclipsed 5% in intraday trading. Following some positive news on the inflation front and indications that the Federal Reserve may cut rates this year, long-duration bond prices have rallied strongly. Over the past 10 weeks, the yield on the 10-year Treasury has declined by about 110 basis points to approximately 3.90%.

Antiquated Infrastructure

For decades, annual capital expenditures on modernizing and upgrading assets such as pipelines and wastewater treatment facilities, were underfunded. For the sake of keeping customers bills low, major maintenance projects were deferred. About 10 to 15 years ago, both the operators of the water facilities and state regulators realized that the situation had to change. Depending upon the source of the information, the general condition of domestic pipelines is substandard, with the average age of pipes being anywhere from 50 to 75 years. As mentioned previously, water utilities have been working to upgrade their systems. Fortunately for them, this is a sort of pay-as-you go type of construction. Electric utilities, for example, have to make huge upfront payments to add a new base load unit. Hence, regulators have had a more-constructive relationship with water companies. However, in the years between the housing crisis of 2007-09 and the pandemic, inflation was very low. This made it easier to pass along high-single-digit rate increases without much pushback from customers. The spike in inflation that was caused by the monetary and fiscal policies aimed at combating COVID-19's impact on the economy has declined, but remains above the Federal Reserve's 2.0% target. Should double-digit rate hikes now be required to finance the construction programs, there could be greater displeasure shown by ratepayers (i.e. voters). This may cause regulators to become more restrictive in their rulings.

Growing Via Acquisitions

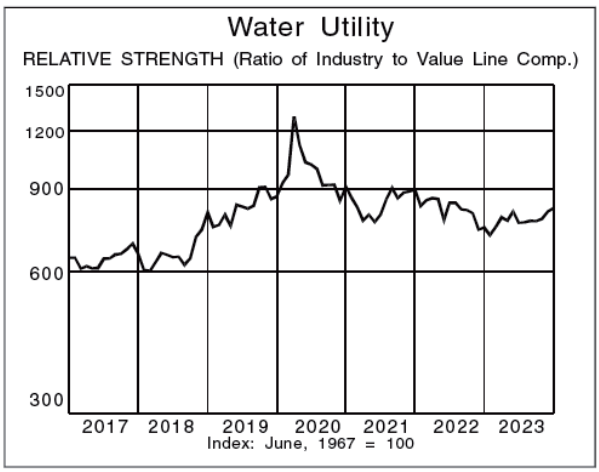
The water industry in the U.S. is mostly run by local, municipal water districts. (There are some major exceptions, such as in New York City.) As a result, there are tens of thousands of these entities operating separately. There is no need for such an immense number, as it leads to inefficiency. Small districts also do not have the financial wherewithal required to fund the needed upgrades. *American Water Works* and *Essential Utilities* are two companies that use bolt-on acquisitions as part of their overall strategy to expand their rate base. These big utilities can easily absorb smaller ones and achieve substantial cost savings by eliminating redundancies.

Conclusion

There are no stocks in this industry that stand out for having favorable short-term total appreciation potential. Despite the bad performance by these equities over the past few years, most continue to have high price-to-earnings ratios and are already trading in their 2026-2028 Target Price Ranges. One of the reasons these equities trade at such a premium is because of scarcity. Investors who want to be in this sector ought to be aware that they will have to pay for the privilege. The only equity followed here that has good long-term total-return potential is *Essential Utilities* and that's probably due to its presence in the gas utility sector.

As always, we strongly recommend that subscribers read each individual comment before investing to better understand the underlying risks associated with each stock.

James A. Flood



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Docket No: UG 490

Staff/108 Muldoon/13

AMER. STATES WATER NYSE-AWR

RECENT PRICE 81.67 | P/E RATIO 29.4 (Trailing: 24.6 Median: 30.0) | RELATIVE P/E RATIO 1.66 | DIV'D YLD 2.2% | VALUE LINE

TIMELINESS 3 Lowered 12/1/23
SAFETY 2 Raised 7/20/12
TECHNICAL 3 Raised 12/15/23
BETA .70 (1.00 = Market)

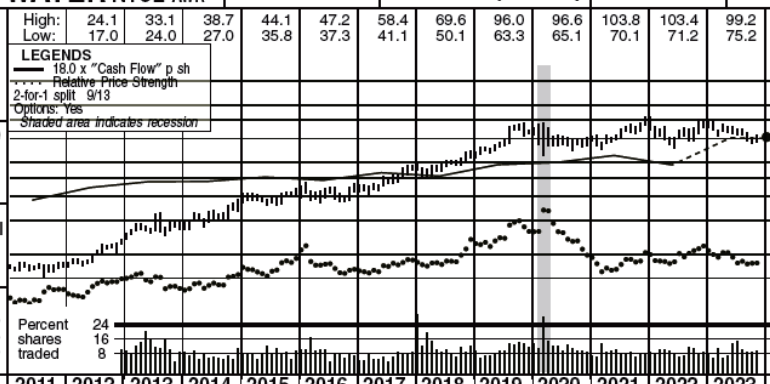
18-Month Target Price Range
Low-High Midpoint (% to Mid)
$66-$134 $100 (20%)

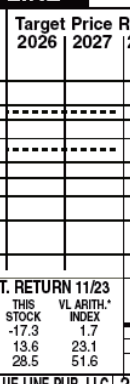
2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	110	(+35%)	10%
Low	70	(-15%)	-1%

Institutional Decisions

	1Q2023	2Q2023	3Q2023
to Buy	124	141	158
to Sell	158	138	133
Hld's(000)	27587	27816	28119





% TOT. RETURN 11/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-17.3	1.7
3 yr.	13.6	23.1
5 yr.	28.5	51.6

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
8.75	9.21	9.74	10.71	11.12	12.12	12.19	12.17	12.56	11.92	12.01	11.88	12.86	13.24	13.51	13.30	*16.35*	*15.05*	Revenues per sh	*19.20*
1.65	1.69	1.70	2.11	2.13	2.48	2.65	2.67	2.81	2.70	2.96	2.84	3.26	3.34	3.64	3.25	*4.60*	*4.20*	"Cash Flow" per sh	*5.05*
.81	.78	.81	1.11	1.12	1.41	1.61	1.57	1.61	1.62	1.88	1.72	2.28	2.33	2.55	2.11	*3.35*	*3.00*	Earnings per sh [A]	*3.40*
.48	.50	.51	.52	.55	.64	.76	.83	.87	.91	.99	1.06	1.16	1.28	1.40	1.53	*1.66*	*1.80*	Div'd Decl'd per sh [B]■	*2.30*
1.45	2.23	2.09	2.12	2.13	1.77	2.52	1.89	2.39	3.55	3.08	3.44	4.12	3.54	3.91	4.50	*4.95*	*5.15*	Cap'l Spending per sh	*4.25*
8.77	8.97	9.70	10.13	10.84	11.80	12.72	13.24	12.77	13.52	14.45	15.19	16.33	17.39	18.57	19.20	*20.95*	*22.30*	Book Value per sh [D]	*24.55*
34.46	34.60	37.06	37.26	37.70	38.53	38.72	38.29	36.50	36.57	36.68	36.76	36.85	36.89	36.94	36.96	*37.00*	*37.25*	Common Shs Outst'g [C]	*37.50*
24.0	22.6	21.2	15.7	15.4	14.3	17.2	20.1	24.6	25.6	25.7	34.0	34.4	34.3	33.2	41.0	*25.8*		Avg Ann'l P/E Ratio	*25.0*
1.27	1.36	1.41	1.00	.97	.91	.97	1.06	1.24	1.34	1.29	1.84	1.83	1.76	1.79	2.38	*1.49*		Relative P/E Ratio	*1.40*
2.5%	2.9%	2.9%	3.0%	3.2%	3.1%	2.7%	2.6%	2.2%	2.2%	2.0%	1.8%	1.5%	1.6%	1.7%	1.8%	*1.9%*		Avg Ann'l Div'd Yield	*2.6%*
472.1	465.8	458.6	436.1	440.6	436.8	473.9	488.2	498.9	491.5	*605*	*560*	Revenues ($mill)	*720*
62.7	61.1	60.5	59.7	69.4	63.9	84.3	86.4	94.3	78.4	*125*	*110*	Net Profit ($mill)	*130*
36.3%	38.4%	38.4%	36.8%	36.0%	22.0%	22.6%	24.6%	24.4%	23.2%	*24.5%*	*24.0%*	Income Tax Rate	*24.0%*
--	--	--	--	--	--	--	--	2.5%	--	*1.5%*	*2.0%*	AFUDC % to Net Profit	*1.5%*
39.8%	39.1%	41.1%	39.4%	38.0%	40.5%	44.4%	47.2%	46.1%	39.9%	*43.5%*	*46.5%*	Long-Term Debt Ratio	*50.0%*
60.2%	60.9%	58.9%	60.6%	62.0%	59.5%	55.6%	52.8%	53.9%	60.1%	*56.5%*	*53.5%*	Common Equity Ratio	*50.0%*
818.4	832.6	791.5	815.3	854.9	938.4	1082.5	1216.2	1272.6	1181.5	*1375*	*1550*	Total Capital ($mill)	*1840*
981.5	1003.5	1060.8	1150.9	1205.0	1296.3	1415.7	1512.0	1626.0	1753.8	*1875*	*1985*	Net Plant ($mill)	*2225*
8.9%	8.6%	9.0%	8.6%	9.3%	7.9%	8.9%	8.0%	8.3%	7.6%	*10.5%*	*9.0%*	Return on Total Cap'l	*8.0%*
12.7%	12.0%	13.0%	12.1%	13.1%	11.4%	14.0%	13.5%	13.8%	11.0%	*16.0%*	*13.5%*	Return on Shr. Equity	*14.0%*
12.7%	12.0%	13.0%	12.1%	13.1%	11.4%	14.0%	13.5%	13.8%	11.0%	*16.0%*	*13.5%*	Return on Com Equity	*14.0%*
6.8%	5.7%	6.0%	5.3%	6.2%	4.5%	6.9%	6.1%	6.2%	3.1%	*10.5%*	*5.5%*	Retained to Com Eq	*4.5%*
47%	53%	54%	56%	52%	61%	51%	55%	55%	72%	*50%*	*60%*	All Div'ds to Net Prof	*68%*

CAPITAL STRUCTURE as of 9/30/23
Total Debt $612.9 mill. Due in 5 Yrs $178.1 mill.
LT Debt $575.5 mill. LT Interest $44.0 mill. (43% of Cap'l)

Leases, Uncapitalized: Annual rentals $2.3 mill.
Pension Assets-12/22 $190.7 mill. Oblig. $186.9 mill.
Pfd Stock None

Common Stock 36,980,592 shs. as of 11/3/23

MARKET CAP: $3.0 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2021	2022	9/30/23
Cash Assets	5.0	6.0	8.6
Accts Receivable	34.4	26.2	32.6
Other	98.7	119.1	150.5
Current Assets	138.1	151.3	191.7
Accts Payable	65.9	84.9	71.8
Debt Due	31.4	255.9	37.4
Other	58.3	55.7	85.9
Current Liab.	155.6	396.5	195.1

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	1.5%	2.0%	*6.5%*
"Cash Flow"	4.5%	4.0%	*7.0%*
Earnings	6.5%	6.5%	*6.5%*
Dividends	9.5%	8.5%	*8.5%*
Book Value	5.5%	6.5%	*5.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2020	109.1	121.3	133.6	124.2	488.2
2021	117.1	128.4	136.8	116.6	498.9
2022	108.6	122.5	135.0	125.4	491.5
2023	161.4	157.4	151.7	*134.5*	*605*
2024	*125*	*132*	*160*	*143*	*560*

Calendar	EARNINGS PER SHARE [A] Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2020	.38	.69	.72	.54	2.33
2021	.52	.72	.76	.55	2.55
2022	.38	.54	.69	.50	2.11
2023	.93	1.04	.85	*.53*	*3.35*
2024	*.60*	*.80*	*.85*	*.75*	*3.00*

Calendar	QUARTERLY DIVIDENDS PAID [B]■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.275	.275	.305	.305	1.16
2020	.305	.305	.335	.335	1.28
2021	.335	.335	.365	.365	1.40
2022	.365	.365	.3975	.3975	1.53
2023	.3975	.3975	.43	.43	

BUSINESS: American States Water Co. operates as a holding company. Through its principal subsidiary, Golden State Water Co., it supplies water to 263,265 customers in 10 California counties. Service areas include the metropolitan areas of Los Angeles and Orange Counties. The company also provides electricity to 24,705 customers in Big Bear Lake and San Bernardino Cnty. Provides water & wastewater services to U.S. military bases through its ASUS subsidiary. Sold Chaparral City Wtr. of AZ. (6/11). Employs 811. BlackRock, Inc. owns 18.6% of out. shares; State St., 16.6%; off. & dir., 0.8% (4/23 Proxy). Chair.: Anne M. Holloway. Pres. & CEO: Robert Sprowls. Inc: CA. Address: 630 East Foothill Blvd., San Dimas, CA 91773. Tel.: 909-394-3600. Int.: www.aswater.com.

Rate relief probably enabled American States Water to complete a successful year. The water utility likely posted record profits last year due to a delay in a ruling by California authorities. According to the law, utilities seeking to raise customer bills to recoup expenses and capital investments must submit an official request to raise rates triennially. The California Public Utility Commission (CPUC) then rules on the petition. American States' Golden Water subsidiary followed the correct methods, but the CPUC issued its ruling very late. The utility was forced to absorb higher costs in 2022. Thus, when the rates were granted last year, they were retroactive to the beginning of 2022. The end result was that American States did poorly in 2022 and exceptionally well in 2023.

The bottom line will likely return to normal in 2024. We think that the company's share earnings can reach $3.00. Though it represents a decline, it will be a decent year. The question is whether the CPUC will permit new rates in 2025 or will make the company wait an additional year, like it did the last time.

Nonutility operations could well provide a lift to earnings growth. State regulators place a limit on the level that a utility can earn. There is less risk and less reward in this model. Through its ASUS subsidiary, the company is involved in managing water services at bases owned by the United States Army. There aren't many entities in this field, so ASUS has been successful in winning its share of bids on new 50-year contracts to service these facilities. Since rates of return aren't regulated in this sector, this business can generate higher returns than Golden States' regulated operations. Through the first three quarters, ASUS has been responsible for 14% of the American States share profits. We look for this percentage to rise as more military installations privatize their water operations.

These shares are ranked to perform in line with the market in the year ahead. Out to 2026-2028, the situation appears to be more unfavorable. Despite solid dividend growth prospects, the equity's total return potential to that time is well below the *Value Line* median.

James A. Flood *January 5, 2024*

(A) Primary earnings. Excludes nonrecurring gains/(losses):; '08, (14¢); '10, (23¢); '11, 10¢. Next earnings report due mid-February.
(B) Dividends historically paid in early March, June, September, and December. ■ Div'd reinvestment plan available.
(C) In millions, adjusted for split.
(D) Includes intangibles. As of 12/31/22; $1.1 million/$0.03 a share.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	85
Earnings Predictability	85

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Docket No: UG 490

Staff/108 Muldoon/14

AMERICAN WATER NYSE-AWK

RECENT PRICE 131.56 | P/E RATIO 26.8 (Trailing: 27.3 Median: 28.0) | RELATIVE P/E RATIO 1.51 | DIV'D YLD 2.3% | VALUE LINE

TIMELINESS 4 Lowered 11/17/23
SAFETY 3 New 7/25/08
TECHNICAL 3 Raised 9/29/23
BETA .95 (1.00 = Market)

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$106-$214 $160 (20%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	200	(+50%)	13%
Low	130	(Nil)	2%

Institutional Decisions

	1Q2023	2Q2023	3Q2023
to Buy	460	436	441
to Sell	404	418	460
Hld's(000)	165074	166259	177196

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
	13.84	14.61	13.98	15.49	15.18	16.25	16.28	16.78	17.72	18.54	18.81	19.04	19.97	20.83	21.58	20.85	*21.45*	*22.55*	Revenues per sh	*26.75*
	d.47	2.87	2.89	3.56	3.73	4.27	4.36	4.75	5.13	5.26	5.14	6.15	6.65	7.24	10.46	8.08	*8.40*	*9.00*	"Cash Flow" per sh	*10.20*
	d2.14	1.10	1.25	1.53	1.72	2.11	2.06	2.39	2.64	2.62	2.38	3.15	3.43	3.91	6.95	4.51	*4.80*	*5.15*	Earnings per sh A	*6.10*
	--	.40	.82	.86	.90	1.21	.84	1.21	1.33	1.47	1.62	1.78	1.96	2.15	2.36	2.57	*2.78*	*3.00*	Div'd Decl'd per sh B■	*3.80*
	4.74	6.31	4.50	4.38	5.27	5.25	5.50	5.33	6.51	7.36	8.04	8.78	9.15	10.05	9.71	12.63	*13.00*	*13.25*	Cap'l Spending per sh	*15.75*
	28.39	25.64	22.91	23.59	24.11	25.11	26.52	27.39	28.25	29.24	30.13	32.42	33.83	35.58	40.18	42.30	*50.95*	*53.25*	Book Value per sh D	*57.25*
	160.00	160.00	174.63	175.00	175.66	176.99	178.25	179.46	178.28	178.10	178.44	180.68	180.81	181.30	181.61	181.86	*195.00*	*195.25*	Common Shs Outst'g C	*200.00*
	--	18.9	15.6	14.6	16.8	16.7	19.9	20.0	20.5	27.7	33.8	27.3	32.9	35.3	23.6	33.6	*29.3*		Avg Ann'l P/E Ratio	*27.0*
	--	1.14	1.04	.93	1.05	1.06	1.12	1.05	1.03	1.45	1.70	1.47	1.75	1.81	1.28	1.95	*1.70*		Relative P/E Ratio	*1.50*
	--	1.9%	4.2%	3.8%	3.1%	3.4%	2.0%	2.5%	2.5%	2.0%	2.0%	2.1%	1.7%	1.6%	1.4%	1.7%	*2.0%*		Avg Ann'l Div'd Yield	*2.3%*
							2901.9	3011.3	3159.0	3302.0	3357.0	3440.0	3610.0	3777.0	3920.0	3792.0	*4180*	*4400*	Revenues ($mill)	*5350*
							369.3	429.8	476.0	468.0	426.0	567.0	621.0	709.0	1263.0	820.0	*935*	*1005*	Net Profit ($mill)	*1220*
							39.1%	39.4%	39.1%	39.2%	53.3%	28.2%	25.5%	23.3%	23.0%	18.7%	*21.0%*	*21.0%*	Income Tax Rate	*24.0%*
							5.1%	--	--	--	--	--	--	--	5.1%	2.9%	*3.5%*	*4.5%*	AFUDC % to Net Profit	*5.0%*
							52.4%	52.4%	53.7%	52.4%	54.7%	56.3%	58.5%	59.1%	58.6%	58.7%	*55.0%*	*57.5%*	Long-Term Debt Ratio	*57.5%*
							47.6%	47.4%	46.2%	47.5%	45.3%	43.6%	41.4%	40.9%	41.4%	41.3%	*45.0%*	*42.5%*	Common Equity Ratio	*42.5%*
							9940.7	10364	10911	10967	11875	13433	14760	15787	17639	18619	*22000*	*24400*	Total Capital ($mill)	*27000*
							12391	12900	13933	14992	16246	17409	18232	19710	21084	23223	*25200*	*27250*	Net Plant ($mill)	*30000*
							5.1%	5.5%	5.7%	5.6%	4.9%	5.4%	5.4%	5.7%	8.2%	5.5%	*6.0%*	*5.5%*	Return on Total Cap'l	*5.5%*
							7.8%	8.7%	9.4%	9.0%	7.9%	9.7%	10.1%	11.0%	17.3%	10.7%	*9.5%*	*9.5%*	Return on Shr. Equity	*10.5%*
							7.8%	8.7%	9.4%	9.0%	7.9%	9.7%	10.1%	11.0%	17.3%	10.7%	*9.5%*	*9.5%*	Return on Com Equity	*10.5%*
							4.7%	4.3%	4.7%	4.0%	2.5%	4.2%	4.4%	5.0%	11.4%	4.6%	*4.0%*	*4.0%*	Retained to Com Eq	*4.5%*
							40%	50%	50%	56%	68%	56%	57%	55%	34%	57%	*58%*	*58%*	All Div'ds to Net Prof	*62%*

CAPITAL STRUCTURE as of 9/30/23
Total Debt $12190 mil. Due in 5 Yrs $2486 mil.
LT Debt $11698 mil. LT Interest $449 mil. (54% of Cap'l)

Leases, Uncapitalized: Annual rentals $9.0 mill.
Pension Assets 12/22 $1578.0 mill
Oblig. $1413.0 mill.
Pfd Stock $2.0 mill. Pfd Div'd $.1 mill

Common Stock 194,704,997 shares as of 10/23/23

MARKET CAP: $25.6 billion (Large Cap)

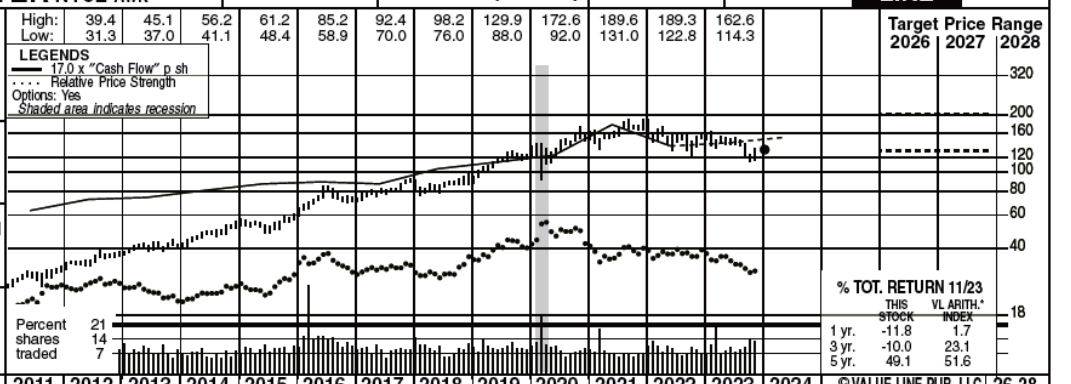
CURRENT POSITION ($MILL.)	2021	2022	9/30/23
Cash Assets	136	117	661
Accts Receivable	271	334	382
Other	1147	799	761
Current Assets	1554	1250	1804
Accts Payable	235	254	228
Debt Due	641	1456	492
Other	1265	1101	1023
Current Liab.	2141	2811	1743

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	3.0%	3.0%	*4.0%*
"Cash Flow"	8.5%	10.5%	*3.0%*
Earnings	11.0%	15.0%	*3.0%*
Dividends	9.0%	10.0%	*8.5%*
Book Value	5.0%	6.0%	*6.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2020	844	931	1079	923	3777
2021	888	999	1082	951	3920
2022	842	937	1082	931	3792
2023	938	1097	1167	*978*	*4180*
2024	*990*	*1150*	*1235*	*1025*	*4400*

Calendar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2020	.68	.97	1.46	.80	3.91
2021	.73	1.14	1.53	3.55	6.95
2022	.87	1.20	1.63	.81	4.51
2023	.91	1.44	1.66	*.79*	*4.80*
2024	*.95*	*1.50*	*1.85*	*.85*	*5.15*

Calendar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.455	.50	.50	.50	1.96
2020	.50	.55	.55	.55	2.15
2021	.55	.6025	.6025	.6025	2.36
2022	.6025	.655	.655	.655	2.57
2023	.655	.7075	.7075	.7075	



BUSINESS: American Water Works Company, Inc. is the largest investor-owned water and wastewater utility in the U.S., providing services to approximately 14 million people in 24 states. Nonregulated business assists municipalities and military bases with the maintenance and upkeep as well. Regulated operations made up 86% of 2022 revenues. New Jersey is its largest market accounting for 25.9% of regulated revenues; Pennsylvania, 23.4%; Missouri, 10.9%. Has 6,500 employees. Vanguard owns 11.7% of outstanding shares; BlackRock, 8.6%; State St., 5.4%; officers & directors, less than 1.0% (3/23 Proxy). President & Chief Executive Officer: Susan Hardwick. . Address: 1 Water Street, Camden, NJ 08102. Telephone: 856-346-8200. Internet: www.amwater.com.

American Water Works intends to continue to expand both its rate base and operating margins via bolt-on acquisitions. The water industry in the U.S. is made up mostly of thousands of small, independent, water districts. Not only are these entities inefficient, but they lack sufficient funds to modernize their antiquated infrastructure. American Water expects to spend $4 billion to $5 billion on these types of purchases through 2033. The company has proven that it can take assets from other utilities and realize substantial cost savings. This increases its revenues and operating margins.

The already massive projected capital expenditure budget has been raised again. Previously, leadership forecast that the 10-year construction program would be in the range of $27 billion to $30 billion. In the most recent presentation made in December of 2023, this budget was hiked 10%-11%, to $30 billion to $33 billion.

The balance sheet ought to be healthy enough to handle these outlays. In the year just ended, we think the water utility spent $2.6 billion on capital expenses. A large equity offering that raised $1.7 billion increased shares outstanding 7%-8%. This was unusual, as management has historically been disinclined to raise money in this fashion. Indeed, the number of shares rose only 2.7% in the previous decade. More debt and some new equity issues will be required going forward. American Water's financial condition should remain at least average, however.

Earnings and dividend growth rates here ought to outpace other members of the industry. Assuming reasonable treatment by regulators on the utility's requests for rate relief (more below), we think annual increases in the payout and bottom line can average 7%-9%.

The wild card is here is the regulatory climate. The company has enjoyed constructive relationships with the authorities who determine its allowed returns. This was before the pandemic, though, when low inflation made it easier to pass along big rate hikes to customers.

These shares are untimely. Moreover, despite the stock's underperformance over the last three years, we think that it still doesn't offer much value to 2026-2028.

James A. Flood *January 5, 2024*

(A) Diluted earnings. Excludes nonrecur. losses: '08, $4.62; '09, $2.63; '11, $0.07. Disc. oper.: '06, ($0.04); '11, $0.03; '12, ($0.10); '13,($0.01). GAAP used as of 2014. Includes $2.70 sh. gain from sale of HOS sub.in Q4,'21. Next earnings report due late mid-February. (B) Dividends paid in March, June, September, and December. ■ Div. reinvestment available. (C) In millions. (D) Includes intangibles. On 12/31/22: $1.225 billion, $6.75/share. (E) Pro forma numbers for '07.

Company's Financial Strength	B++
Stock's Price Stability	80
Price Growth Persistence	75
Earnings Predictability	60

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Docket No: UG 490

Staff/108 Muldoon/15

CALIFORNIA WATER NYSE-CWT

RECENT PRICE 52.29 | P/E RATIO 28.6 (Trailing:NMF Median: 28.0) | RELATIVE P/E RATIO 1.62 | DIV'D YLD 2.0% | VALUE LINE

TIMELINESS 4 Raised 12/22/23
SAFETY 3 Lowered 7/27/07
TECHNICAL 3 Raised 12/15/23
BETA .75 (1.00 = Market)

18-Month Target Price Range

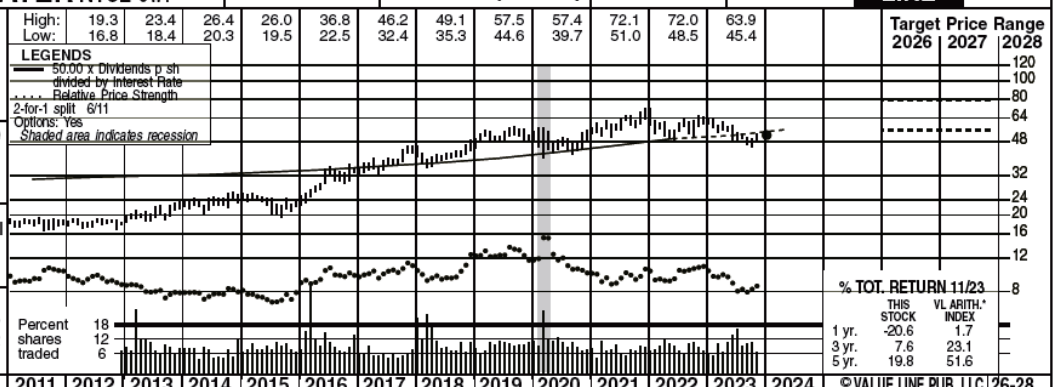
Low-High	Midpoint (% to Mid)
$39-$83	$61 (15%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+55%)	13%
Low	55	(+5%)	4%

Institutional Decisions

	1Q2023	2Q2023	3Q2023
to Buy	125	139	125
to Sell	124	129	127
Hld's(000)	44814	46985	48886



	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
	8.88	9.90	10.82	11.05	12.00	13.34	12.23	12.50	12.29	12.70	13.89	14.53	14.72	15.78	14.72	15.22	*13.95*	*16.10*	Revenues per sh	*19.30*
	1.56	1.86	1.93	1.93	2.07	2.32	2.21	2.47	2.22	2.34	3.00	3.11	3.14	3.88	3.91	3.79	*2.20*	*3.70*	"Cash Flow" per sh	*4.35*
	.75	.95	.98	.91	.86	1.02	1.02	1.19	.94	1.01	1.40	1.36	1.31	1.97	1.96	1.77	*.80*	*2.25*	Earnings per sh [A]	*2.75*
	.58	.59	.59	.60	.62	.63	.64	.65	.67	.69	.72	.75	.79	.85	.92	1.00	*1.04*	*1.12*	Div'd Decl'd per sh [B] ■	*1.35*
	1.84	2.41	2.66	2.97	2.83	3.04	2.58	2.76	3.69	4.77	5.40	5.65	5.64	5.93	5.46	5.90	*6.00*	*6.15*	Cap'l Spending per sh	*6.45*
	9.25	9.72	10.13	10.45	10.76	11.28	12.54	13.11	13.41	13.75	14.44	15.19	16.07	18.30	21.92	23.70	*24.90*	*26.20*	Book Value per sh [C]	*29.50*
	41.33	41.45	41.53	41.67	41.82	41.98	47.74	47.81	47.88	47.97	48.01	48.07	48.53	50.33	53.72	55.60	*57.00*	*55.00*	Common Shs Outst'g [D]	*50.00*
	26.1	19.8	19.7	20.3	21.3	17.9	20.1	19.7	24.8	29.6	26.9	30.3	39.3	24.9	30.5	33.0	*NMF*		Avg Ann'l P/E Ratio	*24.0*
	1.39	1.19	1.31	1.29	1.34	1.14	1.13	1.04	1.25	1.55	1.35	1.64	2.09	1.28	1.65	1.92	*NMF*		Relative P/E Ratio	*1.30*
	3.0%	3.1%	3.1%	3.2%	3.4%	3.5%	3.1%	2.8%	2.9%	2.3%	1.9%	1.8%	1.5%	1.7%	1.5%	1.7%	*1.9%*		Avg Ann'l Div'd Yield	*2.0%*
							584.1	597.5	588.4	609.4	666.9	698.2	714.6	794.3	790.9	846.4	*795*	*885*	Revenues ($mill) [E]	*965*
							47.3	56.7	45.0	48.7	67.2	65.6	63.1	96.8	101.1	96.0	*46.0*	*124*	Net Profit ($mill)	*138*
							30.3%	33.0%	36.0%	35.5%	30.1%	24.5%	19.1%	11.1%	20.1%	3.3%	*21.0%*	*21.0%*	Income Tax Rate	*21.0%*
							4.3%	2.7%	4.3%	6.1%	3.5%	3.1%	5.8%	3.3%	1.7%	1.7%	*5.0%*	*5.0%*	AFUDC % to Net Profit	*5.0%*
							41.6%	40.1%	44.4%	44.6%	42.7%	49.3%	50.2%	45.9%	47.3%	44.4%	*41.5%*	*40.5%*	Long-Term Debt Ratio	*38.0%*
							58.4%	59.9%	55.6%	55.4%	57.3%	50.7%	49.8%	54.1%	52.7%	55.6%	*58.5%*	*59.5%*	Common Equity Ratio	*62.0%*
							1024.9	1045.9	1154.4	1191.2	1209.3	1440.2	1566.7	1702.4	2233.4	2370.1	*2420*	*2415*	Total Capital ($mill)	*2375*
							1515.8	1590.4	1701.8	1859.3	2048.0	2232.7	2406.4	2650.6	2846.9	3058.9	*3175*	*3225*	Net Plant ($mill)	*3450*
							6.0%	6.3%	5.2%	5.5%	7.1%	5.9%	5.5%	7.0%	5.5%	5.0%	*2.5%*	*5.5%*	Return on Total Cap'l	*6.5%*
							7.9%	9.1%	7.0%	7.4%	9.7%	9.0%	8.1%	10.5%	8.6%	7.3%	*3.0%*	*8.5%*	Return on Shr. Equity	*9.5%*
							7.9%	9.1%	7.0%	7.4%	9.7%	9.0%	8.1%	10.5%	8.6%	7.3%	*3.0%*	*8.5%*	Return on Com Equity	*9.5%*
							3.4%	4.1%	2.0%	2.4%	4.7%	4.0%	3.2%	6.0%	4.6%	3.2%	*NMF*	*4.5%*	Retained to Com Eq	*4.5%*
							56%	55%	71%	68%	51%	55%	60%	43%	47%	56%	*NMF*	*50%*	All Div'ds to Net Prof	*49%*

CAPITAL STRUCTURE as of 9/30/23
Total Debt $1069.6 mill. **Due in 5 Yrs** $357.0 mill.
LT Debt $1052.8 mill. **LT Interest** $40.0 mill.
(Total interest coverage: 2.5x) (44% of Cap'l)

Pension Assets-12/22 $637.3 mill.
Oblig. $685.3 mill.

Pfd Stock None

Common Stock 57,711,000 shs.

MARKET CAP: $3.0 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2021	2022	9/30/23
Cash Assets	78.4	62.1	34.7
Other	222.1	233.4	267.6
Current Assets	300.5	295.5	302.3
Accts Payable	144.4	141.0	152.9
Debt Due	40.2	73.3	116.8
Other	72.0	80.4	111.4
Current Liab.	256.6	294.7	381.1

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	2.5%	3.5%	*4.0%*
"Cash Flow"	6.0%	9.0%	*2.0%*
Earnings	7.5%	11.0%	*6.5%*
Dividends	4.0%	6.0%	*6.5%*
Book Value	7.0%	9.0%	*5.5%*

Calendar	QUARTERLY REVENUES ($ mill.)[E] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	125.6	175.5	304.1	189.1	794.3
2021	147.7	213.1	256.7	173.4	790.9
2022	173.0	206.2	266.3	200.9	846.4
2023	131.1	194.0	255.0	*214.9*	*795*
2024	*180*	*210*	*275*	*220*	*885*

Calendar	EARNINGS PER SHARE [A] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	d.42	.11	1.94	.31	1.97
2021	d.06	.75	1.20	.07	1.96
2022	.02	.36	1.03	.35	1.77
2023	d.40	.17	.60	*.43*	*.80*
2024	*.15*	*.60*	*1.00*	*.50*	*2.25*

Calendar	QUARTERLY DIVIDENDS PAID [B] ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.1975	.1975	.1975	.1975	.79
2020	.2125	.2125	.2125	.2125	.85
2021	.230	.230	.230	.230	.92
2022	.250	.250	.250	.250	1.00
2023	.260	.260	.260	.260	

BUSINESS: California Water Service Group provides regulated and nonregulated water service to 496,400 customers in 100 communities in the state of California. Accounts for about 90% of total customers. Also operates in Washington, New Mexico, and Hawaii. Main service areas: San Francisco Bay area, Sacramento Valley, Salinas Valley, San Joaquin Valley & parts of Los Angeles. Acquired Rio Grande Corp; West Hawaii Utilities (9/08). Revenue breakdown, '22: residential, 67%; business, 20%; industrial, 3%; public authorities, 5%; other 5%. Off. and dir. own 1% of common stock (4/23 proxy). Has 1,184 employees. Pres. and CEO: Martin A. Kropelnicki. Inc.: DE. Addr.: 1720 North First St., San Jose, CA 95112-4598. Tel.: 408-367-8200. Internet: www.calwatergroup.com.

California Water Service Group's third-quarter financial results were unfavorably impacted by the state's continued indecision on the pending rate case approval. The company reported revenues of $255 million and earnings of $0.60 per share in the September period, with both figures contracting on an annual basis. Management estimated that a favorable decision would have added approximately $20 million to the top line in the third quarter. Meanwhile, a second judge was assigned to the rate case in late July of last year and, according to regulators, the time line for a decision was extended to the end of 2023. Thus, we expect a ruling on the approval to be imminent.

Our 2023 top- and bottom-line estimates are being reduced at this time. We now look for revenues of $795 million (down from our previous call of $805 million) and earnings of $0.80 per share (down from $0.95). Indeed, the slow-moving rate case gives us pause. Elsewhere, consumer water consumption likely remained soft for the remainder of the year. Moreover, higher operating costs, namely water production, purchased water, and labor expenses, probably persisted.

The long-term picture is notably brighter, however. Assuming the abovementioned rate case is approved by regulators, new customer pricing will be retroactive starting from January 1, 2023. These recouped funds, on top of higher rates going forward, augur well. Meanwhile, management is aggressively investing in upgrading its water system infrastructure ($274 million was spent in the recent period), which suggests that additional rate hike approvals may be pursued down the road. Lastly, a healthier economic backdrop ought to support an uptick in broader residential and business water consumption further out.

From an investment standpoint, California Water shares leave something to be desired at the moment. The stock is ranked to trail the broader market averages over the coming six to 12 months. What's more, at the recent quotation, total return potential three to five years hence is below the *Value Line* median.

Nicholas Patrikis *January 5, 2024*

(A) Basic EPS. Excl. nonrecurring gain (loss): '11, 4¢. Next earnings report due late Feb.
(B) Dividends historically paid in late Feb., May, Aug., and Nov. ■ Div'd reinvestment plan available.
(C) Incl. intangible assets. In '22 : $64.6 mill., $1.16/sh.
(D) In millions, adjusted for split.
(E) Excludes non-regulated revenues.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	80
Earnings Predictability	55

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ESSENTIAL UTIL. NYSE-WTRG

RECENT PRICE 37.14 | P/E RATIO 19.1 (Trailing: 20.6, Median: 26.0) | RELATIVE P/E RATIO 1.08 | DIV'D YLD 3.4% | VALUE LINE

TIMELINESS 4 Lowered 12/22/23
SAFETY 3 Lowered 1/8/21
TECHNICAL 3 Raised 11/24/23
BETA 1.00 (1.00 = Market)

18-Month Target Price Range

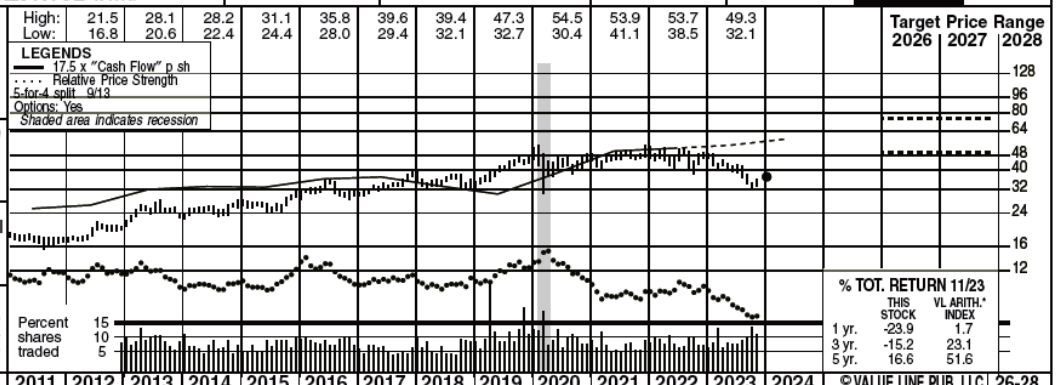
Low-High	Midpoint (% to Mid)
$29-$62	$46 (25%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+100%)	22%
Low	50	(+35%)	11%

Institutional Decisions

	1Q2023	2Q2023	3Q2023
to Buy	268	246	254
to Sell	271	295	275
Hld's(000)	189507	195095	204460



% TOT. RETURN 11/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-23.9	1.7
3 yr.	-15.2	23.1
5 yr.	16.6	51.6

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
3.61	3.71	3.93	4.21	4.10	4.32	4.32	4.37	4.61	4.62	4.56	4.71	4.03	5.96	7.43	8.68	*8.30*	*8.80*	Revenues per sh	*9.10*
1.10	1.14	1.29	1.42	1.45	1.51	1.82	1.89	1.87	2.07	2.12	1.90	1.73	2.21	2.89	2.98	*3.55*	*3.65*	"Cash Flow" per sh	*3.85*
.57	.58	.62	.72	.83	.87	1.16	1.20	1.14	1.32	1.35	1.08	1.04	1.12	1.67	1.77	*1.85*	*2.00*	Earnings per sh	*2.35*
.38	.41	.44	.47	.50	.54	.58	.63	.69	.74	.79	.85	.91	.97	1.04	1.11	*1.19*	*1.27*	Div'd Decl'd per sh	*1.65*
1.43	1.58	1.66	1.89	1.90	1.98	1.73	1.84	2.07	2.16	2.69	2.78	2.49	3.41	4.04	4.03	*4.05*	*4.25*	Cap'l Spending per sh	*3.85*
5.85	6.26	6.50	6.81	7.21	7.90	8.63	9.27	9.78	10.43	11.02	11.28	17.58	19.09	20.50	20.39	*21.85*	*23.10*	Book Value per sh	*25.95*
166.75	169.21	170.61	172.46	173.60	175.43	177.93	178.59	176.54	177.39	177.71	178.09	220.76	245.39	252.87	263.74	*273.30*	*277.00*	Common Shs Outst'g	*285.00*
32.0	24.9	23.1	21.1	21.3	21.9	21.2	20.8	23.5	23.9	24.7	32.6	39.1	39.6	28.3	26.6	*21.8*		Avg Ann'l P/E Ratio	*26.0*
1.70	1.50	1.54	1.34	1.34	1.39	1.19	1.09	1.18	1.25	1.24	1.76	2.08	2.03	1.53	1.54	*1.26*		Relative P/E Ratio	*1.45*
2.1%	2.8%	3.1%	3.1%	2.8%	2.8%	2.4%	2.5%	2.6%	2.3%	2.4%	2.4%	2.2%	2.2%	2.2%	2.4%	*3.0%*		Avg Ann'l Div'd Yield	*2.6%*
						768.6	779.9	814.2	819.9	809.5	838.1	889.7	1462.7	1878.1	2288.0	*2275*	*2435*	Revenues ($mill)	*2600*
						205.0	213.9	201.8	234.2	239.7	192.0	224.5	284.8	431.6	465.2	*505*	*555*	Net Profit ($mill)	*670*
						10.0%	10.5%	6.9%	8.2%	6.6%	--	--	--	--	--	*11.0%*	*14.0%*	Income Tax Rate	*16.0%*
						1.1%	2.4%	3.1%	3.8%	6.3%	6.8%	7.2%	4.5%	4.8%	1.3%	*2.5%*	*3.0%*	AFUDC % to Net Profit	*5.0%*
						48.9%	48.5%	50.3%	48.4%	50.6%	54.4%	43.1%	54.0%	52.7%	54.2%	*52.0%*	*52.5%*	Long-Term Debt Ratio	*56.0%*
						51.1%	51.5%	49.7%	51.6%	49.4%	45.6%	56.9%	46.0%	47.3%	45.8%	*48.0%*	*47.5%*	Common Equity Ratio	*44.0%*
						3003.6	3216.0	3469.5	3587.7	3965.4	4407.8	6824.2	10192	10964	11748	*12500*	*13535*	Total Capital ($mill)	*16800*
						4167.3	4402.0	4688.9	5001.6	5399.9	5930.3	6345.8	9512.9	10252	11131	*12000*	*13000*	Net Plant ($mill)	*14600*
						8.0%	7.8%	6.9%	7.6%	7.1%	5.5%	4.2%	3.7%	4.8%	5.0%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.0%*
						13.4%	12.9%	11.7%	12.7%	12.2%	9.6%	5.8%	6.1%	8.3%	8.7%	*8.5%*	*8.5%*	Return on Shr. Equity	*9.0%*
						13.4%	12.9%	11.7%	12.7%	12.2%	9.6%	5.8%	6.1%	8.3%	8.7%	*8.5%*	*8.5%*	Return on Com Equity	*9.0%*
						6.7%	6.1%	4.7%	5.6%	5.1%	2.1%	.9%	1.1%	3.3%	3.3%	*3.0%*	*2.5%*	Retained to Com Eq	*2.5%*
						50%	52%	60%	56%	59%	79%	84%	82%	60%	62%	*64%*	*64%*	All Div'ds to Net Prof	*70%*

CAPITAL STRUCTURE as of 9/30/23
Total Debt $6806.4 mill. Due in 5 Yrs $1400 mill.
LT Debt $6456.0 mill. LT Interest $254.0 mill. (52% of Cap'l)

Pension Assets-12/22 $333.2 mill.
Oblig. $324.7 mill.

Pfd Stock None
Common Stock 273,165,817 shares as of 10/23/23

MARKET CAP: $10.1 billion (Large Cap)

CURRENT POSITION ($MILL.)	2021	2022	9/30/23
Cash Assets	10.6	11.4	8.5
Receivables	141.0	206.3	133.7
Inventory (AvgCst)	109.6	46.6	48.8
Other	176.6	393.9	218.3
Current Assets	437.8	658.2	409.3
Accts Payable	192.9	238.8	191.9
Debt Due	197.1	427.9	350.4
Other	285.1	355.2	354.3
Current Liab.	675.1	1021.9	896.6

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	5.5%	10.0%	*3.5%*
"Cash Flow"	6.5%	6.0%	*6.0%*
Earnings	6.5%	3.5%	*7.5%*
Dividends	7.5%	7.0%	*8.0%*
Book Value	10.5%	14.0%	*4.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	255.6	384.5	348.6	474.0	1462.7
2021	583.5	397.0	361.9	535.7	1878.1
2022	699.3	448.7	434.6	705.4	2288.0
2023	726.5	436.7	411.1	*700.7*	*2275*
2024	*755*	*475*	*475*	*730*	*2435*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.21	.29	.22	.40	1.12
2021	.72	.32	.19	.44	1.67
2022	.76	.31	.26	.44	1.77
2023	.72	.34	.30	*.49*	*1.85*
2024	*.80*	*.35*	*.30*	*.55*	*2.00*

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.219	.219	.2343	.2343	.91
2020	.2343	.2343	.2507	.2507	.97
2021	.2507	.2507	.2682	.2682	1.04
2022	.2682	.2682	.287	.287	1.11
2023	.287	.287	.3071	.3071	

BUSINESS: Essential Utilities, Inc. became the new name for Aqua America on Feb. 3, 2020, to reflect the acquisition of Peoples, a natural gas utility, which occurred in 3/20. In 2022, Aqua Amer. provided water and wastewater services in the states of PA, OH, TX, IL, NC, NJ, IN, VA NS WS. Acquired AquaSource, 7/13; N. Maine Util., 7/15; and others. Water respn. for 47% of revenues in 2022; residential, 27%; commercial, 7%; industrial, wastewater & other, 13%. Gas 50%; other, 3.0%. Employes 3,178. Off. & dir. own less than 1% of the common stock; BlackRock, 11.2%; Vanguard, 10.1%; Can. Pen. Plan 8.2% (3/23 proxy). Pres. & CEO: Christopher Franklin. Inc.: PA Addr.: 762 W Lancaster Ave., Bryn Mawr, PA 19010. Tel.: 610-525-1400. Int.: www.essential.co.

Essential Utilities posted strong third-quarter results. The water and gas utility company's share earnings of $0.30 were $0.01 above our expectations and a 15% increase over the year-ago period. Regulators allowed the implementation of higher rates on water customers' bills in eight different states. This brought in an additional $42.2 million. On the gas side, higher rates permitted by Pennsylvania and Kentucky state authorities brought in $21.3 million in revenues. Also providing a boost to the bottom line was an almost 3% decrease in operating and maintenance expenses. It should be noted that not all revenue is the same in the utility sector. Essential's top line actually declined 5.4% in the September period on a year-over-year basis. When gas is cheaper on the open market, a utility buys it and sells the gas to clients at the same price. So, it is just a pass-through revenue that doesn't impact net income.

The company likely ended 2023 on a positive note. Ongoing cost controls probably also helped profitability. Along with the rate relief, earnings per share probably increased by double digits. Since first-half earnings fell marginally, full-year earnings per share should have rose 5%.

We expect 2024 to be another decent year. Expenses ought to trend higher, but may be offset by rate relief granted in New Jersey, Ohio, and Virginia in the water segment. Overall, share earnings could rise another 5%-10%.

Essential is another member of the water sector that is increasing its size and income through acquisitions. In the U.S., the water industry is made up of thousands of independent, mostly municipally run entities that are often underfunded and inefficient. Like American Water Works, Essential is absorbing these water districts so that it can substantially widen margins on the purchases through economies of scale. Management thinks that these bolt-on purchases can expand its rate base by 2%-3% annually.

This good-yielding stock is ranked to underperform the market averages in the upcoming year. Looking further out to 2026-2028, shares of Essential have better total return potential than any other member of the Water Utility Industry.

James A. Flood *January 5, 2024*

(A) Diluted egs. Excl. nonrec. gains: '12, 18¢. Excl. gain from disc. operations: '12, 7¢; '13, 9¢; '14, 11¢. Quarterly EPS do not add in '19 due to a large change in the number of shares outstanding in the Dec. period. Next earnings report mid-February.
(B) Dividends historically paid in early March, June, Sept., & Dec. ■ Div'd. reinvestment plan available (5% discount).
(C) In millions, adjusted for stock split.
(D) Includes intangibles: 12/31/22, $2345.4 bill./$8.89 a share.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	65
Earnings Predictability	65

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MIDDLESEX WATER NDQ-MSEX

RECENT PRICE 67.58 | P/E RATIO 29.1 (Trailing: 36.7 Median: 26.0) | RELATIVE P/E RATIO 1.64 | DIV'D YLD 1.9% | VALUE LINE

TIMELINESS 5 Lowered 11/24/23
SAFETY 2 New 10/21/11
TECHNICAL 3 Raised 12/15/23
BETA .75 (1.00 = Market)

18-Month Target Price Range

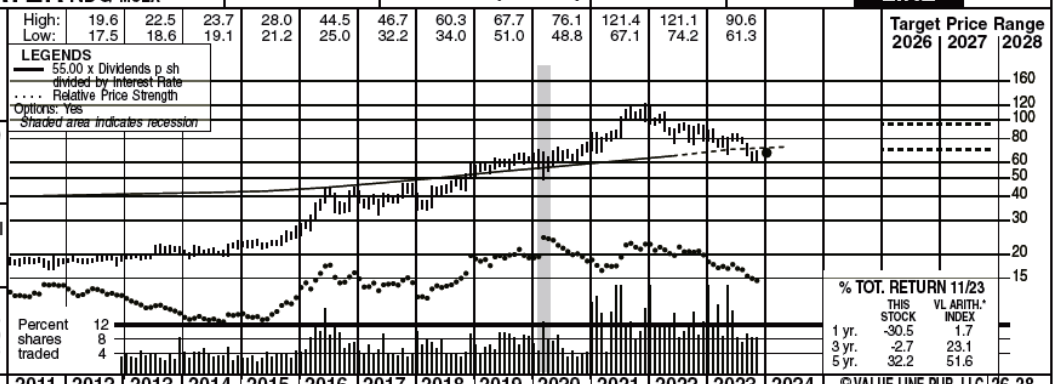
Low-High	Midpoint (% to Mid)
$57-$125	$91 (35%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	95	(+40%)	10%
Low	70	(+5%)	3%

Institutional Decisions

	1Q2023	2Q2023	3Q2023
to Buy	83	75	79
to Sell	96	99	86
Hld's(000)	11875	12584	13355



	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
High:	19.6	22.5	23.7	28.0	44.5	46.7	60.3	67.7	76.1	121.4	121.1	90.6								
Low:	17.5	18.6	19.1	21.2	25.0	32.2	34.0	51.0	48.8	67.1	74.2	61.3								
	6.50	6.79	6.75	6.60	6.50	6.98	7.19	7.26	7.77	8.16	8.00	8.42	7.72	8.10	8.17	9.21	*9.50*	*10.05*	Revenues per sh	*11.10*
	1.49	1.53	1.40	1.55	1.46	1.56	1.72	1.84	1.97	2.17	2.24	2.89	2.90	3.25	3.28	3.70	*3.05*	*3.60*	"Cash Flow" per sh	*4.10*
	.87	.89	.72	.96	.84	.90	1.03	1.13	1.22	1.38	1.38	1.96	2.01	2.18	2.07	2.39	*2.05*	*2.55*	Earnings per sh [A]	*3.00*
	.69	.70	.71	.72	.73	.74	.75	.76	.78	.81	.86	.91	.98	1.04	1.11	1.18	*1.28*	*1.32*	Div'd Decl'd per sh [B]■	*1.60*
	1.66	2.12	1.49	1.90	1.50	1.36	1.26	1.40	1.59	2.91	3.08	4.40	5.11	6.04	4.53	5.18	*5.25*	*5.45*	Cap'l Spending per sh	*6.00*
	10.05	10.03	10.33	11.13	11.27	11.48	11.82	12.24	12.74	13.40	14.02	15.17	18.57	19.81	20.99	22.65	*23.55*	*23.60*	Book Value per sh	*23.70*
	13.25	13.40	13.52	15.57	15.70	15.82	15.96	16.12	16.23	16.30	16.35	16.40	17.43	17.47	17.52	17.64	*17.85*	*17.90*	Common Shs Outst'g [C]	*18.00*
	21.6	19.8	21.0	17.8	21.7	20.8	19.7	18.5	19.1	25.6	28.4	22.2	29.7	30.1	44.3	38.6	*36.9*		Avg Ann'l P/E Ratio	*28.0*
	1.15	1.19	1.40	1.13	1.36	1.32	1.11	.97	.96	1.34	1.43	1.20	1.58	1.55	2.39	2.24	*2.14*		Relative P/E Ratio	*1.30*
	3.7%	4.0%	4.7%	4.2%	4.0%	4.0%	3.7%	3.7%	3.3%	2.3%	2.2%	2.1%	1.6%	1.6%	1.2%	1.3%	*1.7%*		Avg Ann'l Div'd Yield	*1.9%*
							114.8	117.1	126.0	132.9	130.8	138.1	134.6	141.6	143.1	162.4	*170*	*180*	Revenues ($mill)	*200*
							16.6	18.4	20.0	22.7	22.8	32.5	33.9	38.4	36.5	42.4	*36.5*	*45.5*	Net Profit ($mill)	*54.0*
							34.1%	35.0%	34.5%	34.0%	32.7%	2.8%	--	--	2.8%	7.1%	*21.0%*	*21.0%*	Income Tax Rate	*21.0%*
							1.9%	1.7%	1.9%	2.7%	3.1%	1.4%	3.4%	3.9%	3.9%	3.9%	*2.5%*	*2.5%*	AFUDC % to Net Profit	*2.5%*
							40.4%	40.5%	39.4%	37.9%	37.5%	37.8%	41.5%	44.0%	45.3%	41.9%	*44.0%*	*41.5%*	Long-Term Debt Ratio	*40.5%*
							58.7%	58.8%	59.8%	61.5%	61.8%	61.6%	58.2%	55.7%	54.4%	57.7%	*56.0%*	*58.5%*	Common Equity Ratio	*59.5%*
							321.4	335.8	345.4	355.4	370.7	404.1	556.7	621.5	676.3	692.7	*747*	*724*	Total Capital ($mill)	*720*
							446.5	465.4	481.9	517.8	557.2	618.5	705.7	796.6	865.4	920.6	*985*	*995*	Net Plant ($mill)	*1025*
							5.9%	6.3%	6.6%	7.1%	6.9%	8.9%	6.7%	6.8%	6.0%	6.8%	*5.5%*	*6.5%*	Return on Total Cap'l	*8.0%*
							8.7%	9.2%	9.6%	10.3%	9.8%	12.9%	10.4%	11.0%	9.9%	10.5%	*8.5%*	*10.5%*	Return on Shr. Equity	*12.5%*
							8.7%	9.3%	9.6%	10.3%	9.9%	13.0%	10.4%	11.1%	9.9%	10.6%	*8.5%*	*11.0%*	Return on Com Equity	*12.5%*
							2.4%	3.1%	3.5%	4.3%	3.8%	7.0%	5.4%	5.8%	4.6%	5.4%	*3.5%*	*5.0%*	Retained to Com Eq	*6.0%*
							73%	67%	63%	58%	62%	46%	48%	48%	53%	49%	*62%*	*52%*	All Div'ds to Net Prof	*53%*

CAPITAL STRUCTURE as of 9/30/23
Total Debt $361.7 mill. **Due in 5 Yrs** $43.7 mill.
LT Debt $354.3 mill. **LT Interest** $7.5 mill.
(Total interest coverage: 9.3x)
(46% of Cap'l)

Pension Assets-12/22 $84.8 mill.
Oblig. $87.8 mill.
Pfd Stock $2.4 mill. **Pfd Div'd:** $.1 mill.

Common Stock 17,806,000 shs.
as of 11/9/23

MARKET CAP: $1.2 billion (Small Cap)

CURRENT POSITION ($MILL.)	2021	2022	9/30/23
Cash Assets	3.5	3.8	3.0
Other	30.9	33.5	132.8
Current Assets	34.4	37.3	135.8
Accts Payable	21.1	24.8	28.6
Debt Due	6.7	17.5	7.4
Other	28.8	75.6	85.3
Current Liab.	56.6	117.9	121.3

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	2.5%	1.5%	*4.5%*
"Cash Flow"	8.5%	10.0%	*3.0%*
Earnings	9.5%	11.0%	*5.0%*
Dividends	4.0%	6.5%	*6.5%*
Book Value	6.5%	9.5%	*2.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2020	31.8	35.3	39.9	34.6	141.6
2021	32.5	36.7	39.9	34.0	143.1
2022	36.2	39.7	47.7	38.8	162.4
2023	38.2	42.8	46.7	*42.3*	*170*
2024	*42.0*	*43.0*	*52.0*	*43.0*	*180*

Calendar	EARNINGS PER SHARE [A] Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2020	.44	.55	.72	.47	2.18
2021	.39	.62	.65	.41	2.07
2022	.68	.50	.80	.40	2.39
2023	.33	.55	.56	*.61*	*2.05*
2024	*.50*	*.65*	*.75*	*.65*	*2.55*

Calendar	QUARTERLY DIVIDENDS PAID [B]■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.24	.24	.24	.2562	.98
2020	.2562	.2562	.2562	.2725	1.04
2021	.2725	.2725	.2725	.29	1.11
2022	.29	.29	.29	.3125	1.18
2023	.3125	.3125	.3125	.325	

BUSINESS: Middlesex Water Company engages in the ownership and operation of regulated water utility systems in New Jersey, Delaware, and Pennsylvania. It also operates water and wastewater systems under contract on behalf of municipal and private clients in NJ and DE. Its Middlesex System provides water services to 61,000 retail customers, primarily in Middlesex County, New Jersey. In 2022, the Middlesex System accounted for 65% of operating revenues. At 12/31/22, the company had 350 employees. Incorporated: NJ. President, CEO, and Chairman: Dennis W. Doll. Officers & directors own 1.9% of the com. stock; BlackRock Inst. Trust Co., 14.6% (4/23 proxy). Add.: 485 C Route 1 South, Suite 400, Iselin, NJ 08830. Tele.: 732-634-1500. Int.: www.middlesexwater.com.

Middlesex Water stock has treaded water since our previous review. Indeed, the equity, which etched an all-time high in late 2021, has contracted more than 40% in value over the past two years or so. After a prolonged period of relatively conservative allocation strategies, the investment community's appetite for riskier assets appears to have shifted somewhat. On balance, based on recent price and earnings momentum, Middlesex shares do not presently stand out for relative year-ahead price performance (Timeliness: 5, Lowest).

We are trimming our 2023 and 2024 bottom-line estimates subsequent to a softer third-quarter showing. The company posted September-period revenues of $47 million, or $3 million shy of our call. Meanwhile, net income of $0.56 per share, which was flat on a sequential basis, came in considerably below consensus expectations. A combination of lower customer demand and higher purchased water costs weighed on results. All told, we are shaving $0.35 and $0.20 per share from our 2023 and 2024 earnings estimates, to $2.05 and $2.55, respectively.

The board of directors recently raised the quarterly dividend payout 4%, to $0.325 per share. The modest annual increase is in line with the company's historical rate of distribution hikes. Moreover, Middlesex's fairly stable secular business model suggests that additional dividend increases are likely in the cards over the long haul.

Better days probably lie ahead. Looking further out, overall water consumption ought to perk up as economic conditions slowly improve. The company should also benefit from additional rate hike approvals. Capital spending on water infrastructure and delivery systems is likely to keep management active in filing for regulator-approved rate increases.

We think patient investors should also hold off, for now. Capital appreciation potential over the pull to late decade, even on a risk-adjusted basis, is nothing to write home about at recent levels. What's more, the current dividend yield is below the *Value Line* median, thus rendering Middlesex shares unenticing as a stand alone, income-generating option.

Nicholas Patrikis *January 5, 2024*

(A) Diluted earnings. Quarterly figures may not sum due to rounding. Next earnings report due early February.

(B) Dividends historically paid in mid-Feb., May, Aug., and November.■ Div'd reinvestment plan available.

(C) In millions.

Company's Financial Strength	B++
Stock's Price Stability	85
Price Growth Persistence	95
Earnings Predictability	90

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Docket No: UG 490

Staff/108 Muldoon/18

SJW GROUP NYSE-SJW

RECENT PRICE 66.51 | P/E RATIO 21.8 (Trailing: 21.0, Median: 25.0) | RELATIVE P/E RATIO 1.23 | DIV'D YLD 2.3% | VALUE LINE

TIMELINESS 3 Raised 11/10/23
SAFETY 3 New 4/22/11
TECHNICAL 3 Raised 12/22/23
BETA .85 (1.00 = Market)

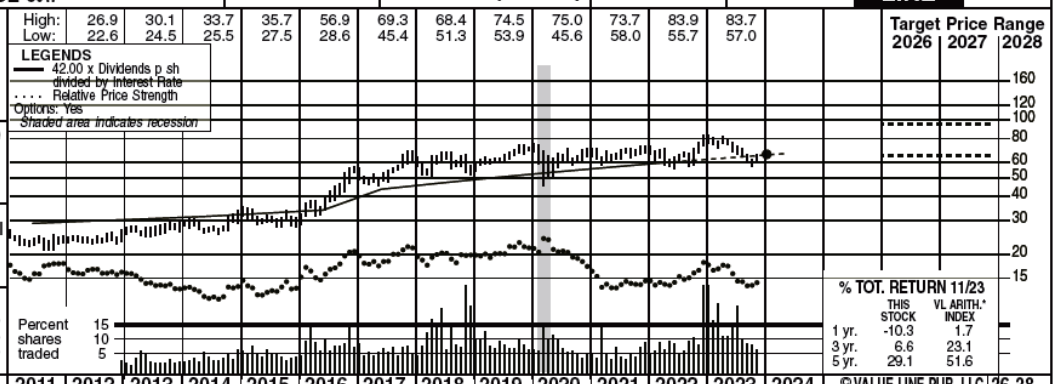
18-Month Target Price Range
Low-High Midpoint (% to Mid)
$54-$110 $82 (25%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	95	(+45%)	11%
Low	65	(Nil)	2%

Institutional Decisions

	1Q2023	2Q2023	3Q2023
to Buy	94	120	128
to Sell	113	91	85
Hld's(000)	27281	26624	24180



2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
11.25	12.12	11.68	11.62	12.85	14.01	13.73	15.76	14.97	16.61	18.97	14.00	14.78	19.77	19.01	20.15	*20.65*	*22.10*	Revenues per sh	*24.15*
2.30	2.44	2.21	2.38	2.80	2.97	2.90	4.42	3.86	4.76	5.24	3.29	3.13	5.28	5.13	5.79	*4.50*	*4.75*	"Cash Flow" per sh	*5.10*
1.04	1.08	.81	.84	1.11	1.18	1.12	2.54	1.85	2.57	2.86	1.82	.82	2.14	2.03	2.43	*2.95*	*3.15*	Earnings per sh [A]	*3.45*
.61	.65	.66	.68	.69	.71	.73	.75	.78	.81	1.04	1.12	1.20	1.28	1.36	1.44	*1.52*	*1.60*	Div'd Decl'd per sh [B]■	*1.80*
6.62	3.79	3.17	5.65	3.75	5.67	4.68	5.02	5.24	6.95	7.26	5.08	6.25	7.44	8.32	7.85	*8.00*	*8.25*	Cap'l Spending per sh	*8.75*
12.90	13.99	13.66	13.75	14.20	14.71	15.92	17.75	18.83	20.61	22.57	31.31	31.27	32.12	34.28	36.06	*38.30*	*41.15*	Book Value per sh	*44.15*
18.36	18.18	18.50	18.55	18.59	18.67	20.17	20.29	20.38	20.46	20.52	28.40	28.46	28.56	30.18	30.80	*32.00*	*31.00*	Common Shs Outst'g [C]	*30.00*
33.4	26.2	28.7	29.1	21.2	20.4	24.3	11.2	16.6	15.7	18.8	32.7	78.8	30.0	32.9	27.3	*24.1*		Avg Ann'l P/E Ratio	*23.0*
1.77	1.58	1.91	1.85	1.33	1.30	1.37	.59	.84	.82	.95	1.77	4.20	1.54	1.78	1.58	*1.40*		Relative P/E Ratio	*1.30*
1.7%	2.3%	2.8%	2.8%	2.9%	3.0%	2.7%	2.6%	2.5%	2.0%	1.9%	1.9%	1.9%	2.0%	2.0%	2.2%	*2.1%*		Avg Ann'l Div'd Yield	*2.3%*
276.9	319.7	305.1	339.7	389.2	397.7	420.5	564.5	573.7	620.7	*660*	*685*	Revenues ($mill)	*725*
23.5	51.8	37.9	52.8	59.2	38.8	23.4	61.5	60.5	73.8	*95.0*	*98.0*	Net Profit ($mill)	*105*
38.7%	32.5%	38.1%	38.8%	36.7%	20.6%	26.4%	12.0%	12.2%	10.3%	*21.0%*	*21.0%*	Income Tax Rate	*21.0%*
--	--	--	--	2.0%	1.0%	2.0%	1.5%	2.0%	6.4%	*1.5%*	*1.5%*	AFUDC % to Net Profit	*1.5%*
51.1%	51.6%	49.8%	50.7%	48.2%	32.7%	59.1%	58.4%	59.1%	57.3%	*55.5%*	*52.5%*	Long-Term Debt Ratio	*43.0%*
48.9%	48.4%	50.2%	49.3%	51.8%	67.3%	40.9%	41.6%	40.9%	42.7%	*44.5%*	*47.5%*	Common Equity Ratio	*57.0%*
656.2	744.5	764.6	855.0	894.3	1320.7	2173.6	2204.7	2527.5	2602.8	*2750*	*2675*	Total Capital ($mill)	*2325*
898.7	963.0	1036.8	1146.4	1239.3	1328.8	2206.5	2334.9	2497.5	2630.3	*2775*	*2800*	Net Plant ($mill)	*2925*
5.0%	8.3%	6.3%	7.4%	7.9%	3.9%	1.8%	4.0%	3.5%	4.0%	*4.0%*	*4.0%*	Return on Total Cap'l	*5.0%*
7.3%	14.4%	9.9%	12.5%	12.8%	4.4%	2.6%	6.7%	5.8%	6.6%	*7.5%*	*7.5%*	Return on Shr. Equity	*8.0%*
7.3%	14.4%	9.9%	12.5%	12.8%	4.4%	2.6%	6.7%	5.8%	6.6%	*7.5%*	*7.5%*	Return on Com Equity	*8.0%*
2.8%	10.2%	5.7%	8.6%	8.2%	1.8%	NMF	2.7%	2.0%	2.7%	*3.5%*	*4.0%*	Retained to Com Eq	*3.5%*
62%	29%	42%	31%	36%	60%	NMF	59%	66%	59%	*51%*	*51%*	All Div'ds to Net Prof	*52%*

CAPITAL STRUCTURE as of 9/30/23
Total Debt $1577.3 mill. Due in 5 Yrs $44.3 mill.
LT Debt $1533.8 mill. LT Interest $50.0 mill.
(LT Interest Coverage: 10.2x)
(57% of Cap'l)

Pension Assets-12/22 $252.0 mill.
Oblig. $289.1 mill.
Pfd Stock None.
Common Stock 31,933,000 shs.

MARKET CAP: $2.1 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2021	2022	9/30/23
Cash Assets	10.9	12.3	21.1
Accts Receivable	53.7	58.2	70.4
Other	69.5	84.2	137.3
Current Assets	134.1	154.7	228.8
Accts Payable	30.4	29.6	35.9
Debt Due	39.1	4.4	43.5
Other	133.8	230.7	228.7
Current Liab.	203.3	264.7	308.1

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	4.5%	3.0%	*3.5%*
"Cash Flow"	7.0%	3.0%	*-1.0%*
Earnings	7.5%	-2.0%	*8.0%*
Dividends	7.0%	9.0%	*5.0%*
Book Value	9.0%	10.5%	*4.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2020	115.8	147.2	165.9	135.6	564.5
2021	114.8	152.2	166.9	139.8	573.7
2022	124.3	149.0	176.0	171.4	620.7
2023	137.3	156.9	204.8	*161.0*	*660*
2024	*140*	*165*	*215*	*165*	*685*

Calendar	EARNINGS PER SHARE [A] Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2020	.08	.69	.91	.46	2.14
2021	.09	.69	.64	.60	2.03
2022	.12	.38	.82	1.09	2.43
2023	.37	.58	1.13	*.87*	*2.95*
2024	*.45*	*.60*	*1.20*	*.90*	*3.15*

Calendar	QUARTERLY DIVIDENDS PAID [B]■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.30	.30	.30	.30	1.20
2020	.32	.32	.32	.32	1.28
2021	.34	.34	.34	.34	1.36
2022	.36	.36	.36	.36	1.44
2023	.38	.38	.38	.38	

BUSINESS: SJW Group engages in the production, purchase, storage, purification, distribution, and retail sale of water. It provides water service to approximately 231,000 connections with a total population of roughly one million people in the San Jose area and 16,000 connections that reach about 49,000 residents in the region between San Antonio and Austin, Texas. The company merged with Connecticut Water (10/19) which provides service to approx. 138,000 connections with a total population of 450,000 people. Has 757 employees. Officers and directors own less than 1.0% of outstanding shares (3/23 proxy). Chairman & CEO: Eric Thornburg. Incorporated: California. Address: 110 West Taylor Street, San Jose, CA 95110. Telephone: (408) 279-7800. Internet: www.sjwater.com.

SJW Group closed two acquisitions in Texas during the September period. Subsidiary Texas Water Company finalized the purchase of KT Water Development and KT Water Resources for undisclosed amounts. The former provides diverse water services to residential water connections, while the latter is a water wholesaler that will greatly increase Texas Water Company's available water supply over the next several years.

Third-quarter financial results were solid. SJW Group recorded revenues of $205 million, or a 16% annual advance. The gain was underpinned by recent rate increases and higher customer water usages, particularly amidst the end of the state's conservation requirements. On the earnings front, net income jumped 38%, to $1.13 per share, driven largely by strong top-line gains that more than offset a slight uptick in operating expenses, such as water production costs. As a result, we are raising our 2023 revenue and earnings calls from $640 million and $2.75 per share, to $660 million and $2.95 per share, respectively. We think moderate growth is also in the cards for 2024.

Rate case filings ought to continue in the coming years. Most recently, higher customer rates went into effect in Maine and California. Elsewhere, in October, SJW's subsidiary Connecticut Water Company filed an application with state regulators to amend rates. Filings have also been proposed in Texas. In the meantime, management is not likely to take its foot off the gas, in terms of infrastructure investment spending. In fact, the company plans to invest more than $1.5 billion over the next five years, of which a decent portion is expected to be recouped via additional rate hike approvals.

We are not presently recommending this stock. SJW shares are ranked to move in line with the broader market averages over the coming six to 12 months. Moreover, the current dividend yield is roughly on par with that of the *Value Line* median. On balance, total return potential over the 2026-2028 horizon does not stand out at recent levels. All told, we suggest that subscribers looking for exposure to regulated water utilities have a look elsewhere, for now.

Nicholas Patrikis *January 5, 2024*

(A) Diluted earnings. Excludes nonrecurring losses: '08, $1.22; '10, $0.46. GAAP accounting as of 2013. Next earnings report due early February. Quarterly egs. may not add due to rounding.
(B) Dividends historically paid in early March, June, September, and December. ■ Div'd reinvestment plan available.
(C) In millions.
(D) Paid special dividend of $0.17 per share on 11/17.

Company's Financial Strength	B+
Stock's Price Stability	90
Price Growth Persistence	70
Earnings Predictability	50

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PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 109

ROE: Financial News that Investors in Electric Utilities Are Seeing

April 18, 2024

Docket No. UG 490

Staff/109 Muldoon/1

S&P Global

RRA Regulatory Focus

Major Energy Rate Case Decisions

February 6, 2024

Major energy rate case decisions in the US

January-December 2023

Quarterly update on decided rate cases

Lisa Fontanella, **Research Director**

Contributors: Brian Collins, Jim Davis, Russell Ernst, Lillian Federico, Monica Hlinka, Jason Lehmann, Dan Lowrey

Editor: Wyatt Scott

For detailed data

Access the RRA's electric and gas rate case decisions as of Dec. 31, 2023, data tables.

Energy authorized returns on equity rose in 2023 as the pace of rate case activity reached record-high levels, with nearly 165 decisions issued by state public utility commissions, including 106 electric or gas equity return determinations.

To learn more or to request a demo, visit spglobal.com/marketintelligence.

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Executive Summary

Introduction

Energy authorized returns on equity rose in 2023 as the pace of rate case activity reached record-high levels.

As per calculations from Regulatory Research Associates, the average authorized return on equity (ROE) for electric utilities in cases decided during 2023 was 9.60%, compared to the 9.54% average for cases decided in 2022. There were 63 electric ROE determinations reflected in the calculations for 2023 versus 53 in 2022.

Despite the rise in 2023, the average authorized ROE for electric utilities in 2023 remains near historic lows and was the sixth-lowest annual average over the more than 40 years RRA has tracked rate case activity.

The average ROE authorized for gas utilities was 9.64% for cases decided during 2023 versus the 9.53% average observed in 2022. RRA's calculations relied on 43 gas rate case decisions that included an ROE determination during 2023 versus 33 in 2022. For gas utilities, the average authorized ROE in 2023 was the seventh-lowest annual average on record.

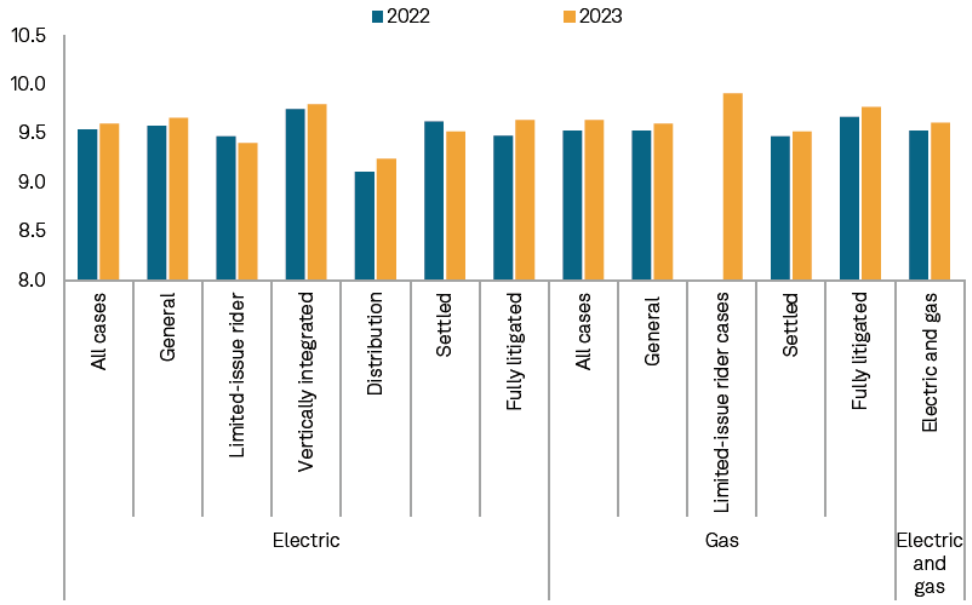
Rate case activity reached record-high levels in 2023, with nearly 165 decisions issued by state public utility commissions, including 106 electric or gas equity return determinations.

While the reasons for a rate case filing are numerous, the main driver continues to be the recovery of capital expenditures. Energy utilities are investing in infrastructure to modernize transmission and distribution systems, build new natural gas, solar and wind generation, and deploy new technologies to accommodate the expansion of electric vehicles, battery storage and advanced metering infrastructure that facilitate the transition toward decarbonization. Other reasons for rate filings include rising expenses, revised cost-of-capital parameters, the impact of broader economic and sector-wide forces on operations, the need to address rate treatment to be accorded generation facilities being retired prior to the end of their planned service lives due to the energy transition, recovery of storm and severe-weather related costs, and regulatory approval for alternative regulatory mechanisms.

About this report

This quarterly report offers a detailed overview of electric and gas rate case decisions issued in the US during 2023 and select aggregated historical data. The information presented in this report utilizes the data compiled by Regulatory Research Associates for its rate case database, which is available on the S&P Capital IQ Pro platform. RRA endeavors to follow all "major" rate cases for investor-owned utilities nationwide, with "major" defined as a case in which the utility's request would result in a rate change of at least $5 million or in which the commission approves a rate change of at least $3 million. In addition to base rate cases, the rate case history database includes details regarding certain limited-issue rider proceedings, primarily those involving significant rate base additions recognized outside of a general rate case. In some of these cases, the rate change coverage criteria may not apply. Historical data in this report may not match earlier data provided in previous reports due to differences in presentation, including the treatment of withdrawn or dismissed cases and the addition of cases not previously included in RRA's coverage.

Average authorized ROE (%)



	2022	2023
Electric averages		
All cases	9.54	9.60
General rate cases	9.58	9.66
Limited-issue rider cases	9.47	9.40
Vertically integrated cases	9.75	9.80
Distribution cases	9.11	9.24
Settled cases	9.62	9.52
Fully litigated cases	9.48	9.64
Gas averages		
All cases	9.53	9.64
General rate cases	9.53	9.60
Limited-issue rider cases		9.91
Settled cases	9.47	9.52
Fully litigated cases	9.67	9.77
Composite electric and gas averages		
Electric and gas	9.53	9.61
US Treasury		
30-year bond yield	3.11	4.09

Data compiled Jan. 26, 2024.
ROE = return on equity.
Sources: Regulatory Research Associates, a group within S&P Global Commodity Insights; US Treasury Department.
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The Take

The average authorized returns in 2023 edged modestly higher than the annual levels observed in 2022 as higher interest rates began to impact authorized ROEs. The effect of interest rate increases on authorized returns will likely be limited, however, given that regulators are slower to adjust ROEs upward than downward, and affordability concerns persist as regulators contend with customer rate increases stemming from significant but necessary capital investment in the energy transition during a period of high inflation.

In recent years, rate case activity for investor-owned electric and gas utilities in the US has been elevated, with state public utility commissions issuing almost 165 decisions in 2023. With higher interest rates, higher inflation and accelerating capital spending to address public policy goals, particularly the energy transition, RRA anticipates rate case filings will remain robust.

Overview of electric and gas authorizations

The average electric and gas authorized returns on equity inched gently higher per averages calculated for 2023.

The average ROE authorized for electric utilities rose to 9.60% for rate cases decided in 2023 from the 9.54% average observed in 2022. There were 63 electric ROE determinations reflected in the calculations for 2023 versus 53 in full year 2022.

The average ROE authorized for gas utilities was 9.64% for cases decided in 2023, above the 9.53% average observed in 2022. There were 43 gas rate case decisions decided in 2023 versus 33 in full year 2022.

The electric data set includes several limited-issue rider cases. Historically, the ROEs authorized in limited-issue rider cases were meaningfully higher than those approved in general rate cases, driven primarily by incentives allowed in Virginia for certain types of generation investment. These premiums have largely expired. Excluding rider cases, the average authorized ROE for electric cases was 9.66% in 2023 versus 9.58% in full year 2022.

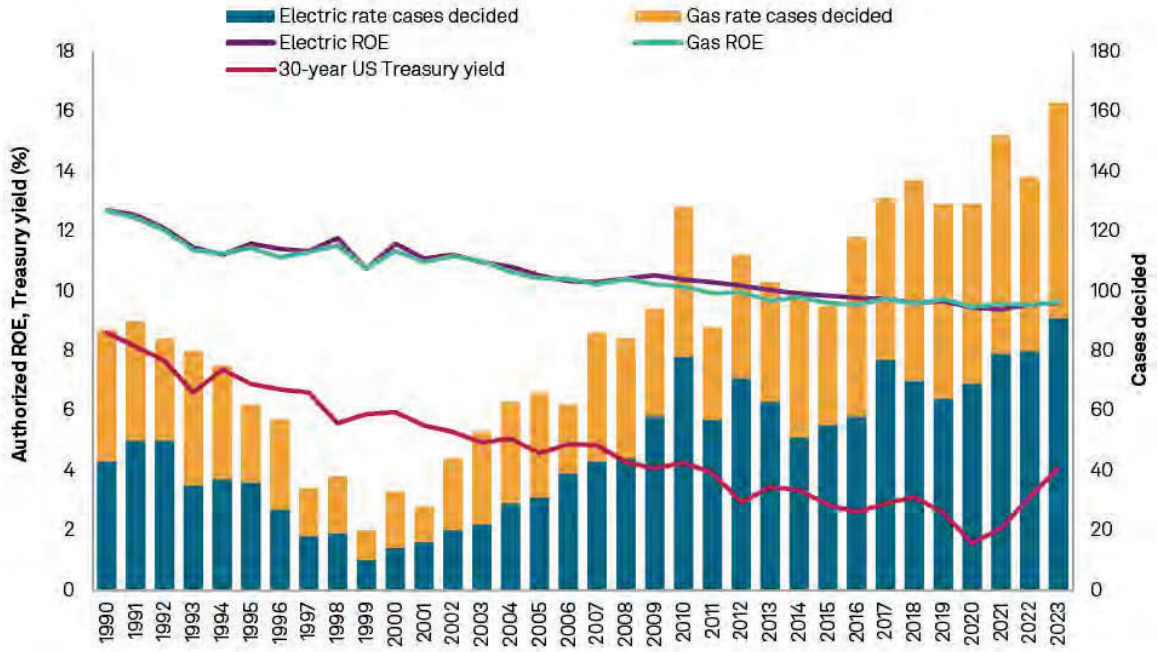
Excluding the six rider cases, the average authorized ROE for gas cases was 9.60% in 2023. There were no rider cases with a gas-authorized ROE in 2022. For the most part, limited-issue riders have a limited impact on average ROEs in the gas sector, as most of the gas riders rely on ROEs approved in a previous base rate case.

In 2023, the median ROE authorized in all electric utility rate cases was 9.50%, equal to that observed in 2022; for gas utilities, the metric was 9.64% in 2023 and 9.53% in full year 2022.

Historically, authorized returns have generally tracked the overall direction of interest rates, albeit with two important caveats to keep in mind — the magnitude of the change in authorized ROEs may not be as dramatic as that observed in interest rates, and changes in authorized ROEs may lag changes in interest rates, especially in the upward direction.

Interest rates — as measured by the 30-year US Treasury bond yield — fell almost steadily between 1990 and 2020, placing downward pressure on authorized ROEs. Between 1990 and 2020, Treasury yields fell more than 700 basis points, to 1.56% from 8.61%, while average authorized ROEs for electric and gas utilities combined fell less than 325 basis points, to 9.45% from 12.69%. The average authorized ROEs did not fall below 10% until 2011 for gas utilities and until 2014 for electric utilities. The calendar-year averages fell below 9.50% for the first time in 2020.

Average electric, gas authorized ROEs; number of rate cases decided



Data compiled Jan. 26, 2024.
ROE = return on equity.
Sources: Regulatory Research Associates, a group within S&P Global Commodity Insights; US Treasury Department.
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The decline in authorized ROEs has coincided with an upswing in rate case activity, with 100 or more cases adjudicated in 12 of the last 15 calendar years. This count includes electric and gas cases where no ROEs were specified, but it does not include withdrawn cases. At almost 165 cases decided, rate case activity in 2023 was the most robust observed in any year during the 1990–2023 period, with authorized increases totaling about $12 billion.

With interest rates and authorized ROEs declining at different rates between 1990 and 2020, the spread between authorized ROEs and the average yield on 30-year US Treasuries somewhat widened over this period — from a little over 400 basis points in 1990 to peaking at just under 800 basis points in 2020.

This occurrence is attributable primarily to the regulators' often-unstated understanding that the drop in interest rates caused by the Fed intervention was unusual. Consequently, regulators did not necessarily fully reflect the interest rate drop in newly authorized ROEs in some instances; in others, regulators acknowledged that the changing dynamics of the industry and instability in the overall economy presented increased risks for investors, justifying a higher premium over interest rates.

However, with the uptick in interest rates since 2020, the spread has begun to narrow, falling to around 550 basis points in 2023.

With the myriad factors putting upward pressure on customer bills, the spread may continue to narrow as regulators may become more reluctant to raise authorized returns.

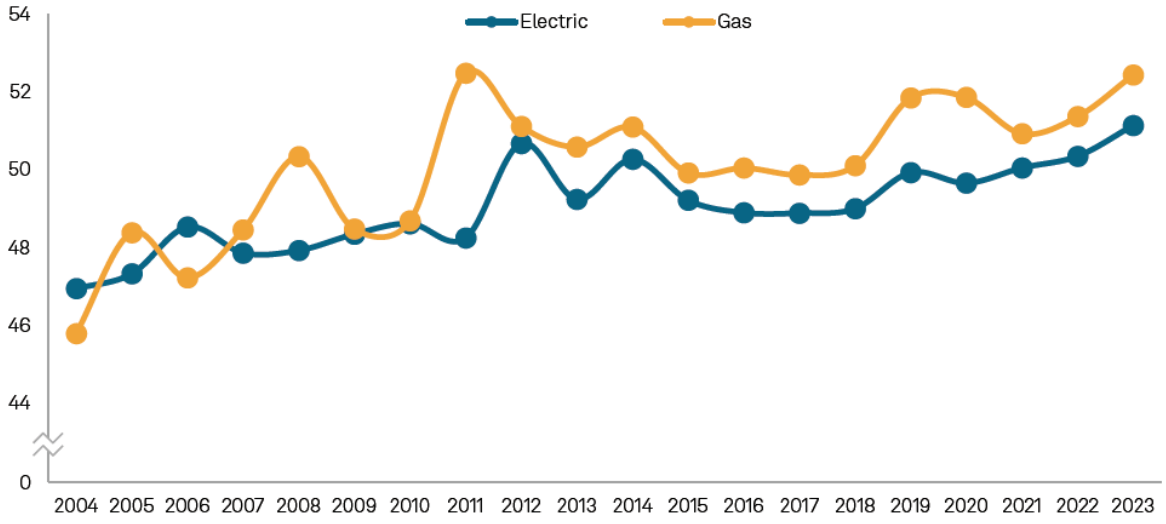
Capital structure trends

The negative cash flow impact of federal tax changes that took effect in 2018 raised concerns regarding utility liquidity and credit metrics. In response, many utilities sought higher common equity ratios, and the average authorized equity ratios adopted by utility commissions in 2019 were modestly higher than those observed in 2018 and 2017.

For full years 2023, 2022, 2021, 2020, and 2019, the average equity ratios authorized in electric utility cases were 51.15%, 50.36%, 50.06%, 49.67% and 49.94%, respectively. The average equity ratios authorized gas utilities for these years were 52.45%, 51.38%, 50.94%, 51.87% and 51.86%, respectively.

From a longer-term perspective, equity ratios have generally increased over the last several years — the average equity ratio approved in electric rate cases decided during 2004 was 46.96%, while the average for gas utilities was 45.81%. Many commissions began approving more equity-rich capital structures in the wake of the 2008 financial crisis. For the bulk of the period since 2004, allowed equity ratios for gas utilities have been above those authorized for electric utilities.

Average authorized equity ratio (%)



Data compiled Jan. 26, 2024.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.
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A more granular look at ROE trends

Thus far, the discussion has looked broadly at trends in authorized ROEs; the following sections provide a more granular view.

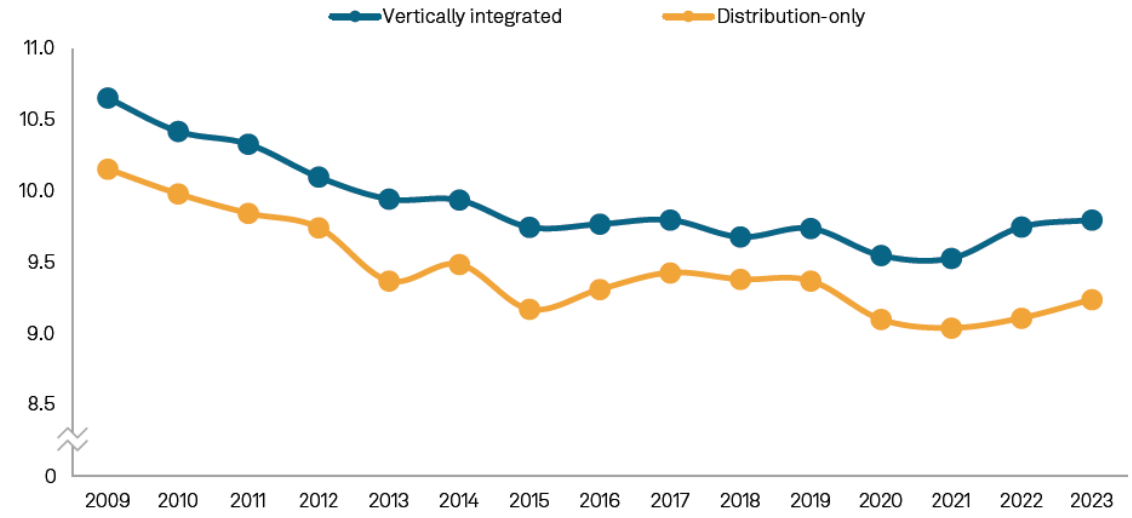
RRA has observed that there can be significant differences between average ROEs based on the types of proceedings/decisions in which these ROEs were established.

As a result of the electric industry restructuring, certain states unbundled electric rates and implemented retail competition for generation. Commissions in those states now have jurisdiction only over the revenue requirement and return parameters for distribution operations.

RRA finds that the annual average authorized ROEs in vertically integrated cases involving generation have been about 30–65 basis points higher than in distribution-only cases, arguably reflecting the increased risk associated with the ownership and operation of generation assets.

The industry average ROE for vertically integrated electric utilities was 9.80% in 2023 versus the 9.75% average in 2022. For electric distribution-only cases, the industry average ROE was 9.24% in 2023 versus the 9.11% average in 2022.

Average authorized electric ROEs (%)



Data compiled Jan. 26, 2024.
ROE = return on equity.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.
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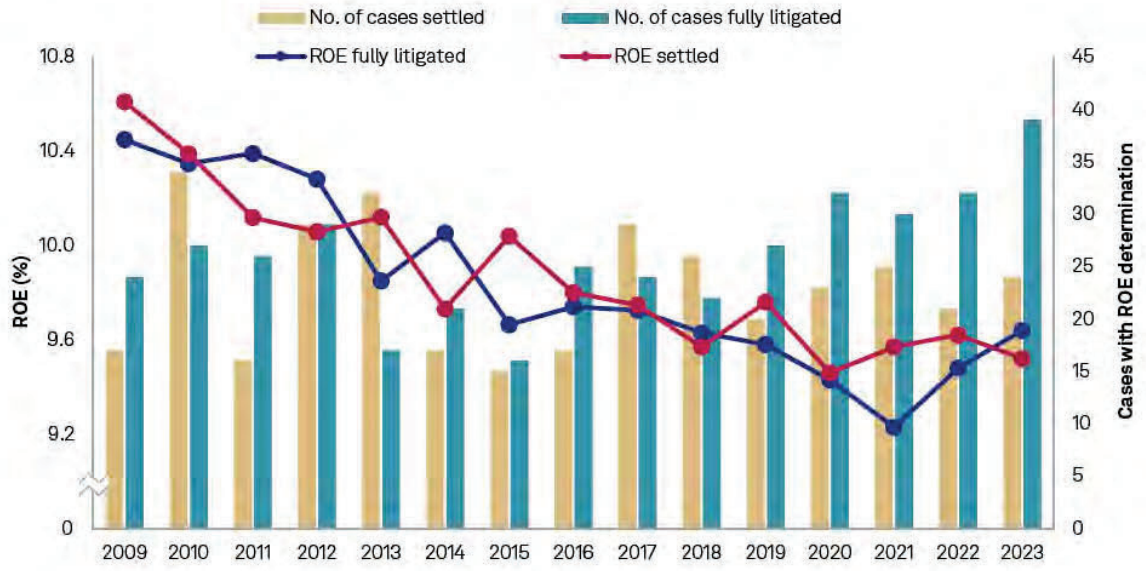
Settlements have frequently been used to resolve rate cases over the last several years, and in many cases, these settlements are “black box” in nature and do not specify the ROE and other typical rate case parameters underlying the stipulated rate change. Some states, however, preclude this type of treatment, and settlements must specify these values, if not the specific adjustments from which these values were derived.

For both electric and gas cases, RRA has found no discernible pattern in the average authorized ROEs in cases that were settled versus those that were fully litigated. In some years, the average authorized ROE was higher for fully litigated cases, while in others, it was higher for settled cases.

Docket No. UG 490 Staff/109 Muldoon/9

Average authorized electric ROEs: settled vs. fully litigated cases



Data compiled Jan. 26, 2024.
ROE = return on equity.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.
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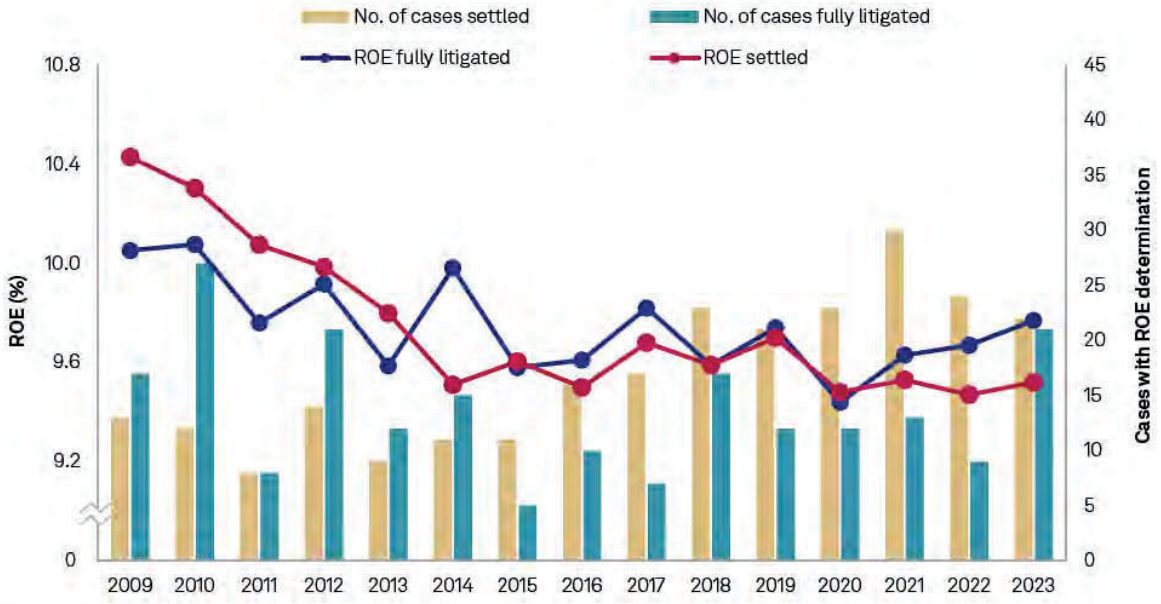
Average authorized gas ROEs: settled vs. fully litigated cases



Data compiled Jan. 26, 2024.
ROE = return on equity.
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The following discussion focuses on the corresponding tables available here.

Table 1 shows the average ROE authorized in major electric and gas rate decisions annually since 1990 and quarterly since 2019, followed by the number of observations in each period. **Table 2** indicates the composite electric and gas industry data for all major cases, summarized annually since 2004 and quarterly since 2021.

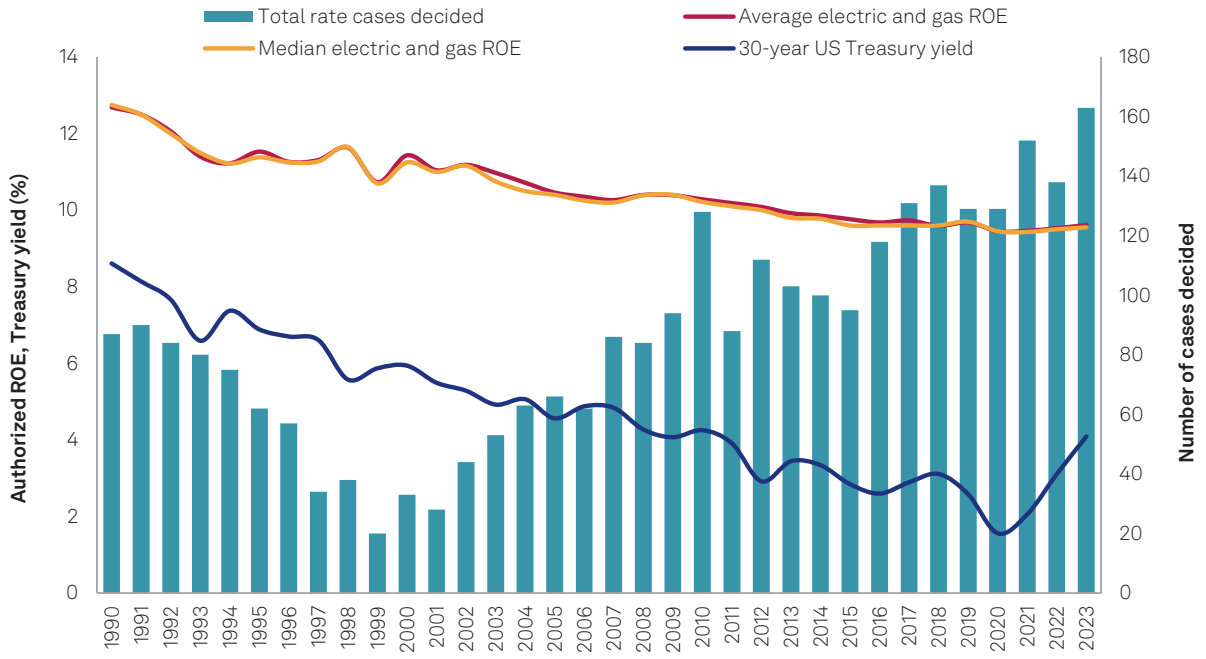
Tables 3 and 4 provide comparisons since 2009 of average authorized ROEs for settled versus fully litigated cases, general rate cases versus limited-issue rider proceedings and vertically integrated cases versus delivery-only cases for electric and gas utilities, respectively.

The individual electric and gas cases decided in 2023 are listed in **Table 5**, with the decision date shown first, followed by the company name, the abbreviation for the state issuing the decision, the authorized rate of return, the ROE and the percentage of common equity in the adopted capital structure. Next, RRA indicates the month and year in which the adopted test year ended, whether the commission utilized an average or a year-end rate base and the amount of the permanent rate change authorized. The dollar amounts represent the permanent rate change ordered at the time the decisions were rendered. This study does not reflect fuel adjustment clause rate changes.

The simple mean is utilized for the return averages. In addition, the average equity returns indicated in this report reflect the ROEs approved in cases decided during the specified time periods and are not necessarily representative of the average currently authorized ROEs for utilities industrywide or the returns earned by the utilities.

Table 6 and the graph below track the combined average and median equity return authorized for all electric and gas rate cases since 1990. As the table indicates, since 1990, authorized ROEs have generally trended downward, reflecting the significant decline in interest rates and capital costs over this time frame.

Composite electric, gas average authorized ROEs; total number of rate cases



Data compiled Jan. 26, 2024.
ROE = return on equity.
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Further Reading

The Commissions

The rate case process: a conduit to enlightenment

Rate base: It's more complicated than it sounds

Frequently Asked Questions

Intro to Water Utilities — Current Trends and Growth Drivers

An Overview of FERC Regulation

FERC Regulatory Review

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About Regulatory Research Associates

Regulatory Research Associates, a group within S&P Global Commodity Insights, is the leading authority on utility securities and regulation. Understanding the financial and strategic impact of federal and state regulation is a key to success in the energy business. For over 40 years, Regulatory Research Associates has been the leading provider of independent research, expert analysis, proprietary data and consultation on utility securities and regulation. S&P Global Commodity Insights produces content for distribution on S&P Capital IQ Pro.

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The Citizens' Utility Board Asked the Oregon Public Utility Commission to Dismiss Portland General Electric's Rate Request for 2025

by Pete Danko – Portland Business Journal – Mar. 15, 2024

In what it called an "unprecedented appeal" to regulators, **Oregon's residential ratepayer advocate** on Thursday formally **asked** the **P**ublic **U**tility **C**ommission to **dismiss P**ortland **G**eneral **E**lectric's **latest proposed rate increase**.

PGE late last month requested a 7.4% overall average rate increase in 2025, 7.2% for the residential customers that the Citizens' Utility Board represents. It would come on the heels of an 18% overall increase that hit PGE residential customers in January, with a smaller but not yet set rate boost for wildfire mitigation costs still due to kick in this April.

Rates also rose in 2023, and the new PGE request would push PGE prices some 40% above where they stood in 2022, according to CUB.

Something 'never done before'.

"We're asking the Commission to do something they have never done before," **Bob Jenks**, **CUB**'s executive director, **said** in a news release. "We are seeing historically high bills for many PGE customers, and we **need regulators** to **do something bold and unprecedented**. Now is the time to flip the script and show our utilities that consumer protections come before profits."

A PGE representative, responding to a request for comment, emailed that "PGE is and will continue to be fully engaged in the public Rate Review process administered by the Oregon Public Utility Commission."

If not a dismissal, **CUB asked the PUC** to "**segregate**" **several issues from PGE's request**, **including PGE's ask for** an **increase** in its **return on equity** — its profit margin, in essence — **from 9.5% to 9.75%**. **CUB said many of those issues** were **fought** over **in last year's PGE general rate case**.

"The **Company seeks** to re**-litigate many** of the **contentious issues** that were collaboratively resolved and determined to result in just and **reasonable** rates mere weeks earlier," it said in the PUC filing.

CUB said it was **supported in** its **motion by Lewis & Clark Law School's Green Energy Institute and** the Alliance of **W**estern **E**nergy **C**onsumers, which represents big energy users.

Rates are ultimately set by the three-person, governor-appointed PUC after a 10-month process that includes regulatory staff analysis and stakeholder and public input.

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PGE's Battery Investments

With rates already on the rise, PGE executives earlier last month had told investment analysts that the company would look to file a narrowly focused general rate case, mostly to pay for new battery energy storage systems it expects to bring online next year.

But CUB saw the request that came less than two weeks later as far from narrow. Out of a $202 million revenue requirement boost, just $17.3 million was directly attributable to the battery systems.

PGE says associated substation costs also need to be paid for, along with other transmission and distribution system upgrades that it says will improve reliability and help it meet growing load.

–

Consumer Group asks Oregon Regulators to Dismiss New PGE Rate Hike Request

by Gosia Wozniacka - Oregonian – Mar. 15, 2024

A state nonprofit group that advocates for utility customers is asking Oregon regulators to dismiss Portland General Electric's newest rate increase proposal.

In a motion filed Thursday, the Oregon **C**itizens' **U**tility **B**oard **asked** the **P**ublic **U**tility **C**ommission to **throw out PGE's 7.4% increase request**. If approved by the commission, the increase would take effect in January 2025.

The **C**itzens' **U**tility **B**oard, which was **created via** a **1984 ballot measure**, said in a statement that it has never taken such an action before and is doing so now "in the face of record bills for PGE customers."

The board points out that PGE's residential customers have seen a 30% increase in power bills over the past two years. Their rates went up 12% in January 2023 and by 18% this past January.

Customers are reeling from record-high bills that resulted from this year's rate increase and the ice storm in January and many won't be able to handle yet another increase, said Bob Jenks, the board's executive director.

Jenks said the utility's latest request for 2025 will likely grow to cover other costs such as wildfire mitigation or winter storm recovery.

"We're asking the Commission to do something they have never done before," Jenks said. "We are seeing historically high bills for many PGE customers, and we need regulators to do something bold and unprecedented."

The **P**ublic **U**tility **C**ommission regulates investor-owned electric and other utilities. Commission spokesperson **Kandi Young said** the **Commission's normal practice**

would be to seek written replies from its staff and other parties and then issue a written ruling after reviewing responses. **But** Oregon **CUB's petition asks** the **Commission instead** to **decide** the **motion at** a **public meeting**.

"The Commission is considering CUB's request for a change to the standard process, and will advise parties when written responses are due," Young told The Oregonian/OregonLive via email.

PGE declined to comment on the petition and said it would continue to focus on its rate increase proposal.

"PGE is and will continue to be fully engaged in the public Rate Review process administered by the Oregon Public Utility Commission," the utility's spokesperson, Drew Hanson, said in an email.

PGE's 7.4% rate increase request is tied to clean energy needs – specifically, battery storage projects, PGE said previously.

In its petition, the Citizens' Utility Board told regulators that its review of the request found that the new Constable **Battery Storage** project, which is what's included in PGE's rate increase proposal, will cost only $17.3 million, or 8.5% of the total $202 million revenue demand.

The rest, said **Jenks**, will go toward higher profits for shareholders and shifting financial risk to customers, among other things – issues the **commission already ruled** on and rejected in **December for** the **increase that went into effect this year**.

If the **P**ublic **U**tilities **C**ommission **will not dismiss PGE's entire rate increase case**, the **C**itizens' **U**tility **B**oard **asks** that it **limit** the **scope** of what PGE can request, including **removing all** of the **items** that the **commission previously ruled against**.

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Is Oregon Utility Regulation Part of the Problem?

by Bob Jenks – Oregon CUB – Jan. 25, 2024
Is Oregon Utility Regulation Part of the Problem? | Latest News | News | Oregon CUB

As utility bills in Oregon continue to rise in 2024, CUB is asking tough questions from state regulators. Currently, utility regulators spend a lot of time looking at many requests from utilities to raise rates. This analysis can take up to 10 months in many cases. But overall affordability to customers is not part of the equation for regulators.

We need to look at utility bills holistically – before we see rates skyrocket. Our current system means that customer advocates, decision-makers, and customers do not have a clear picture of what to expect from utility bills. And an even harder time knowing when rates will go up dramatically.

Exposing Flaws in Oregon's System of Utility Regulation

From December 2022 to January 2024, Portland General Electric (PGE) customers have seen bills go up by 30%. This large increase in 13 months shows real and significant flaws in Oregon's system of regulation utilities.

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Our current structure leads regulation to focus on each individual line item, but not on the overall affordability of rates. There are several parts to this problem:

- Utilities have an incentive to spend money.
- Utilities can request dozens of rate increases a year.
- **Regulator looks at individual utility projects, not total rates.**
- Costs can be updated even after they are approved by regulators.
- Utilities work to keep information confidential from the public.

Electric utilities are typically the ones who see the most frequent requests for rate increases. PGE is not the only utility that has had large bill increases in the past few years. Pacific Power customers saw bills increase by 21% at the start of 2023 and by 11% on January 1, 2024.

Increasingly, gas utilities are also asking for more from customers more often. Alongside the big spikes in the cost of methane, NW Natural gas rates have increased by 32.7% since September 2022.

Utilities have an incentive to spend money

Utilities make a profit from making capital investments. This ability to profit from a new power plant, laying new lines, or other projects is protected by Oregon law. While many investments are necessary to maintain a reliable system, too many investments can cause rates to be unaffordable.

To justify a capital expense, a utility normally has to show that the investment was expected to bring benefits to the system and to customers. But affordability to customers is not part of the equation for regulators.

Example: Wildfire Mitigation

After the 2020 Labor Day fires, it became clear that utilities needed to invest money in wildfire mitigation. Oregon's utilities are now spending hundreds of millions of dollars to mitigate potential wildfires. Since a wildfire caused by a utility line can cause significant harm, it would be hard to argue that this is not a prudent and necessary investment.

For utilities, wildfire mitigation was an opportunity to spend money and increase profits. Did they ask whether this was affordable for customers? Did they look at other investments to see if there were costs that could be avoided or delayed?

Read More: **Protecting Oregon Customers from Wildfire Risk and Cost Increases**

Regulation Looks at Individual Investments, Not Total Rates

Under Oregon law, regulators at the Public Utility Commission are supposed to establish fair and reasonable rates. What regulators do not consider is how these costs affect customers overall.

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When a utility asks regulators if it can charge customers more money, it brings a list of investments and expenses. Regulators go down the list, examining each cost to see if it is reasonable and justifiable. They ask questions like: Will this cost provide a benefit to the energy system? Will this investment be able to be used for its expected lifetime?

What **regulators do not ask**: How much will approving this cost increase customer bills? **What other costs is** the **utility asking for that will increase bills**? Can customers afford this large of an overall increase?

Investments.

When a utility makes an investment, it is motivated by profit first and meeting basic standards of providing service second. What is not considered is how an investment will impact the people they are charging.

While adding many new upgrades to the utility's system may help the system, when combined their cost may be beyond the reach of most customers when they are added to the bill. With neither utilities nor regulators considering whether families can afford total energy bills, a lot of pressure falls on advocates like CUB.

Single-Issue Rate-Making Makes Controlling Costs More Difficult

Holistic Utility Regulation: Under traditional regulation, regulators consider utilities' investments, the overall cost of providing service, profits, and more. For a long time, the holistic model was the standard for utility regulation. Over the past couple of decades, utilities have increasingly asked for surcharges outside of this process.

Single Issue Regulation (Surcharges): In the case of single-issue rate-making, regulators typically only look at the utility costs and surcharge requests related to a single issue. One recent example of a single-issue surcharge is the Wildfire Mitigation cases mentioned above. PGE and Pacific Power both asked to add a surcharge to cover costs related to wildfire prevention. Other examples of single-issue requests include surcharges to cover costs associated with the 2021 ice storm and pilot programs for electric vehicle investments.

Right now, electric utilities are the ones most likely to use the surcharge method to raise rates. But gas utilities are also able to use this tactic. Across the country, energy utilities are using single-issue regulation more and more often to get more and more money from customers

Costs are Updated After Regulators Review Them

In some of these mechanisms, PGE will file a proposal but is allowed to update the proposal. In the case of power costs, the final update is after the Commission actually issues its final order in the case. This means the Commission is expected to make a decision without knowing the rate that is established.

Lack of Transparency on Rate Impacts

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In order to protect trade secrets, utilities are allowed to designate some information as **confidential**. But utilities abuse this process. When PGE updates its power cost forecasts in power cost cases, it designates the expected price increase as confidential. CUB cannot think of any reason why a forecasted rate increase could ever be considered confidential. But it does make it difficult to inform the public about what their rates will be, and it makes public discussion of future rate hikes more difficult.

Enough is Enough.

PGE's rates have **increased** by **30% in** the **last 13 months**. But no one has reviewed the overall rate level and asked the question: Are rates fair and reasonable?

Using the Tools in Regulators' Toolbelts

Regulators at the Public Utility Commission have tools that they can use to lower the impact to customers.

Directing Utilities to Adjust Expenses

First, the Commission can order a utility to propose and implement other measures to reduce **rate shock**. The regulators could tell the utility to **delay certain expenses**. They could also direct utilities to take other **cost-cutting measures**, reducing the need for a rate increase altogether.

Delaying Increases

Second, when regulators approve a rate increase, they can order the utility to delay some of that increase until sometime in the future. By **delaying increases**, electric customers in particular can avoid a large increase during winter when energy usage is the highest.

In the case of PGE's 2024 increase, regulators asked the utility to delay an additional 2% increase until the spring. In 2023, Pacific Power delayed the rollout of its 21% increase until the spring, lessening the impact of the winter heating season.

By delaying increases, regulators can help protect customers from surprisingly high bills during the winter months. This could be the difference between a household being able to keep the heat on or facing disconnection.

Tying Customer Costs to Allowable Profits

Third, regulators can add incentives to keep costs low by **lowering allowable profit margins** if the cost to customers is not controlled.

CUB is Pushing for Policy Changes

State utility regulators are required to set some costs, such as utility profits, at a reasonable level. However, the **P**ublic **U**tility **C**ommission **can set** the **rate at** the **lowest level** that is **considered reasonable**. For example, the **Commission might determine** that a **reasonable profit margin is anything between 9.0% and 10.0%**. Under normal circumstances, the Commission might set that margin at the midpoint or 9.5%.

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But **to mitigate a large rate increase**, the **Commission can set** the **profit margin at** the **lowest point** which is **reasonable or 9.0%.** Lowering profits will lower the rate increase for customers. This is an important tool because it tells utilities that if they cannot control their costs, it will reduce their profit margins.

CUB advocates are hard at work this year to create lasting change to protect customers from more bill increases. In 2024, we are facing multiple requests from utilities to increase rates again. Oregonians from Newport to Ontario could be impacted.

Reduce the Number of Increases

A big policy issue for CUB this year is to **reduce** the **number of rate requests** that **utilities** are **asking for each year**. We have been pushing back against the rising tide of surcharges facing Oregon energy customers.

In the PGE case, CUB continued to fight for a more holistic approach to utility regulation and won on several issues we raised. Now, PGE is consolidating some of their requests and has dropped others. This is good for customers' ability to know what to expect from bills down the line.

Read more: **Are Utility Customers Being Nickled and Dimed? - CUB Blog**

Pushing for New Policy: Avoid Large Bill Spikes in the Winter

Regulators did the right thing in delaying even more increases for PGE customers this winter. Now, CUB is calling on the Public Utility Commission to make spreading high rate increases a standard practice to prevent disastrous winter bills for Oregonians.

While CUB has negotiated delays in winter increases with utilities, this is the first time in recent memory that the Commission has made such a request. Without this delay, customers could have seen a higher bill increase in January, a month that typically brings the highest energy bills of the year.

Stay Up to Date on Oregon Utility Issues

CUB will continue to advocate for people in Oregon on major utility issues. **Sign up for the CUB email list** for the latest updates, action alerts, and news on policies that affect the utilities your home relies on.

Donate to CUB

To keep up with CUB, like us on **Facebook** and follow us on **Twitter!**

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It's Been 30 Years Since Food Ate Up This Much of Your Income

by Jesse Newman and Heather Haddon – WSJ – Feb 26, 2024

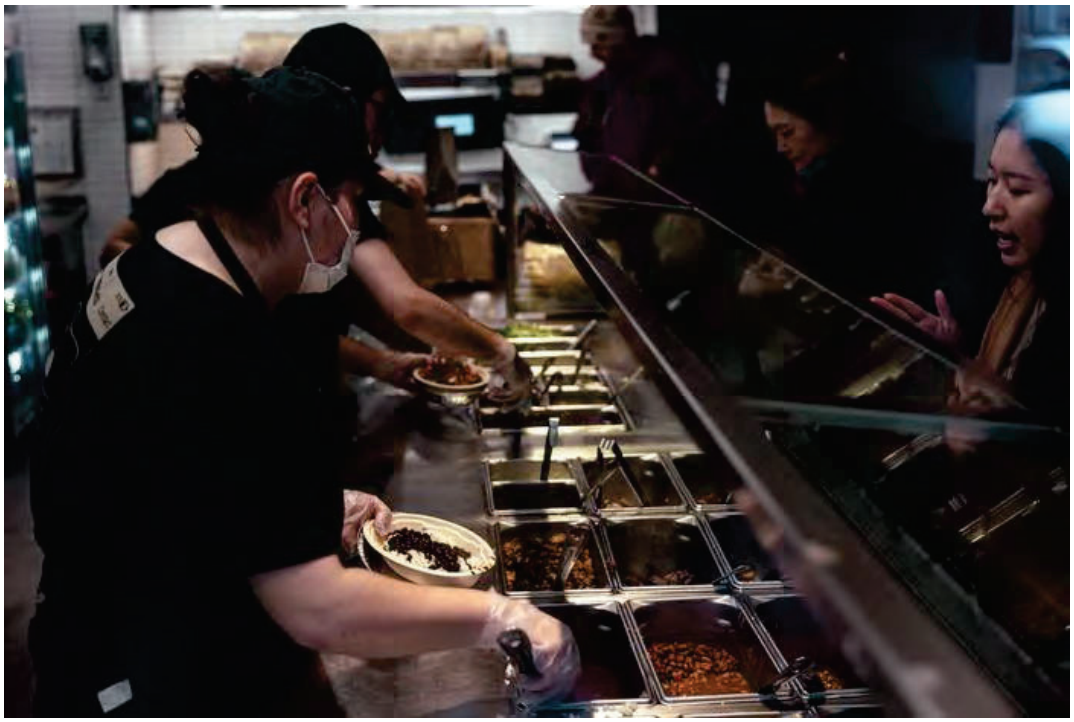
Ongoing high costs lead food manufacturers and restaurants to keep prices elevated.

The last time Americans spent this much of their money on food, George H.W. Bush was in office, "Terminator 2: Judgment Day" was in theaters and C+C Music Factory was rocking the Billboard charts.

Eating continues to cost more, even as overall inflation has eased from the blistering pace consumers endured throughout much of 2022 and 2023. Prices at restaurants and other eateries were up 5.1% last month compared with January 2023, while grocery costs increased 1.2% during the same period, Labor Department data show.

Relief isn't likely to arrive soon. Restaurant and food company executives said they are still grappling with rising labor costs and some ingredients, such as cocoa, that are only getting more expensive. Consumers, they said, will find ways to cope.

"If you look **historically after periods** of **inflation**, there's really **no period** you could point to **where** [**food**] **prices go back down**," said Steve Cahillane, chief executive of snack giant Kellanova , in an interview. "They **tend to be sticky**."



Companies are set to pay more for staffing, after 22 states in January lifted the minimum wage for hourly workers.

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In **1991**, **U.S. consumers spent 11.4%** of their **disposable personal income on food**, according to data from the U.S. Agriculture Department. At the time, households were still dealing with steep food-price increases following an inflationary period during the 1970s.

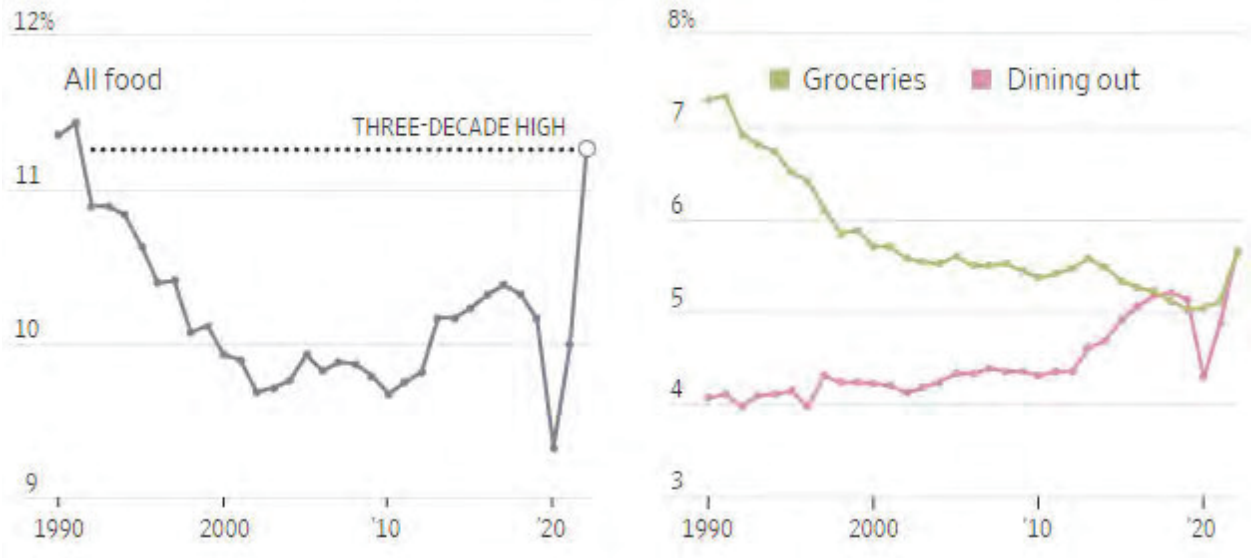
More than three decades later, food spending has reattained that level, USDA data shows. In **2022**, **consumers spent 11.3%** of their **disposable income on food**, according to the most recent USDA data available.

Many diners have said they are going out less frequently or skipping appetizers, while buying cheaper store brands more frequently at supermarkets and seeking out promotions or deals offered via apps. That is starting to chip away at some sales for food makers and restaurant operators.

Food companies said they are feeling pinched themselves. While commodities such as corn, wheat, coffee beans and chicken have gotten cheaper, prices for sugar, beef and french fries are still high or rising. Companies across the U.S. economy have also raised prices beyond covering their own higher expenses, lifting profits for industries including retail, biotech and manufacturing.

Food inflation has raised the ire of President Biden, who took to Instagram during the Super Bowl to blast food makers that he said were providing less bang for consumers' buck – putting fewer chips in each bag or shrinking the size of ice-cream containers.

Food spending's share of disposable income



Source: Agriculture Department

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"The American public is tired of being played for suckers," Biden said. "I've had enough of what they call **shrinkflation**. It's a rip-off."

David Chavern, CEO of the Consumer Brands Association, which represents major food manufacturers, said the industry offers many choices at different price points. "We hope to work with the president on real solutions that benefit consumers," he said.

In suburban Chicago, Lisa Wister said her food bills are rising faster than her family's income, leading them to make their own granola from scratch and pack their own snacks for the movies. "Everything is a negotiation, an analysis about our budget," said Wister, an occupational therapist. "It's exhausting."

Denny's, Wendy's and other restaurant chains told investors this month that their guest counts fell last year compared with 2022 levels as consumers, in particular those with lower incomes, feel the financial pinch. Big food makers including Hershey and Kraft Heinz have reported that their sales volumes declined as prices rose for their products, with several reporting a hit to profits in the latest fiscal year – and others an increase.

Oreo maker Mondelez said in January it would continue raising prices on some of its products this year, largely because of cocoa prices, which earlier in February surged past a 46-year record. Hershey said this month it expects more expensive cocoa to cut into the company's profit this year. Kraft Heinz said inflation is moderating but that its costs are still higher, driven in part by pricier tomatoes and sugar.

Companies are set to pay more for staffing, after 22 states in January lifted the minimum wage for hourly workers. Hiring skilled workers like mechanics to replace employees who retired during the pandemic is particularly expensive, said Henk Hartong, CEO of Brynwood Partners, which owns 17 food and beverage plants that make Pillsbury cake mixes and other products.

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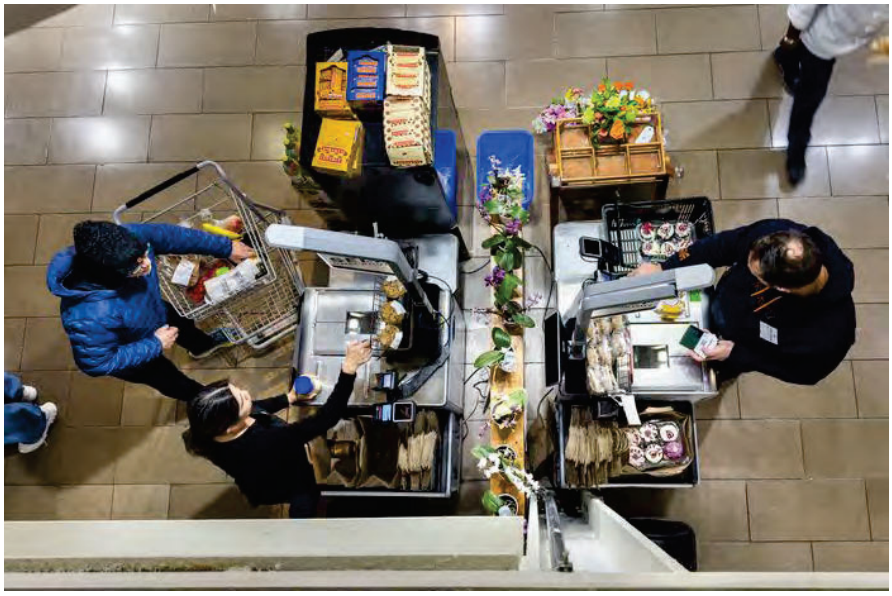

Many people say they are buying cheaper store brands more frequently at supermarkets.

Restaurant chains said they are trying to operate more efficiently to help defray wage increases, but they also expect to raise prices.

"It's a really fast move and a high percent increase," Chipotle Mexican Grill CEO Brian Niccol said in an interview, referring to California's 25% minimum wage increase for fast-food workers employed by large chains, set to take effect in April. "Pricing is going to be part of the puzzle."

Some restaurant and food companies, including Kraft Heinz, Mondelez International and Olive Garden owner Darden Restaurants , are projecting higher earnings this year. Signs of a consumer-spending slowdown has led others to temper their outlooks, with same-store sales projection for 2024 and frozen-foods maker Conagra reducing its per-share earnings forecast.

Investors have cooled on food stocks. An S&P 500 subindex of restaurant stocks has risen 10% in the past 12 months through Wednesday's close, while the broader index gained about 25%. An S&P subindex tracking packaged food and meat companies fell roughly 8% over that period.

When Anna Zabinski and her husband eat out these days, she said, they ask themselves whether a side of macaroni and cheese is worth the extra $1.99, and often go for refills instead of ordering more expensive large-size drinks.

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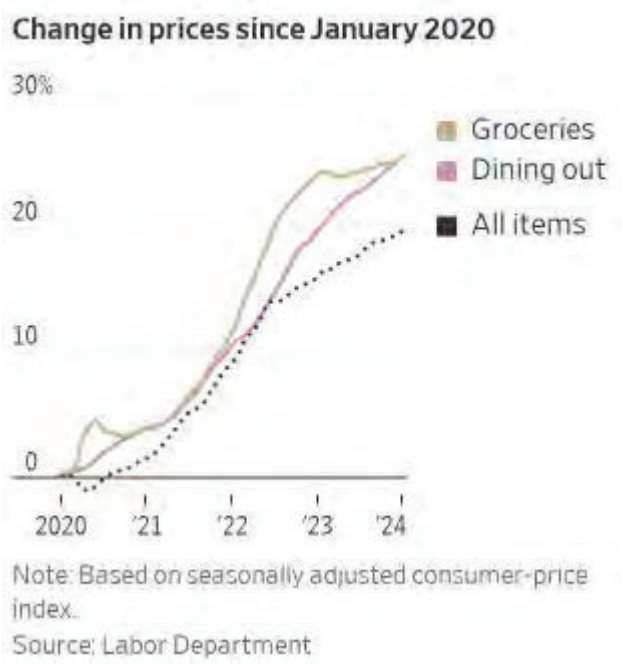

Zabinski, a professor from Normal, Ill., said they'll sometimes split a $20 steak and side dish at Texas Roadhouse or a large sandwich from Jimmy John's. Nonetheless, she said, "our daily and monthly expenditures still seem higher than even two years ago."

Food manufacturers and restaurants have been offering more deals on some items. J.M. Smucker and Conagra have reduced prices on coffee and margarine, passing through lower costs for coffee beans and edible oils. McDonald's and Wendy's said they would offer deals this year aimed at consumers seeking relief from rising prices.

Gary Pilnick, chief executive of WK Kellogg, said the company has been working to market cereals such as Frosted Flakes and Froot Loops to pressured consumers. An ad campaign launched in 2022, for example, encouraged consumers to eat cereal for dinner, pitching it as an easy, inexpensive alternative that, combined with milk and fruit, costs less than $1 per serving. "Give chicken the night off," the campaign's tagline says.

Although it is **rare for food prices to retreat**, it is **also unusual for prices** to **skyrocket as much as** they have in **recent years**, said TD Cowen analyst Robert Moskow. He said he expects grocery prices to decline for a period this year as food makers come under pressure from consumers and retailers.

Kraft Heinz said it is focused on providing affordable options for families, and that while its costs rose 3% in 2023, it raised prices by 1%. WK Kellogg said that before raising prices, the company tries to combat higher costs through greater productivity.

Kellanova said it is working to keep prices as low as possible. Cahillane declined to comment on pricing for his company's products this year but said that the maker of Pringles and Pop-Tarts hasn't raised prices to pad its profit.

Cahillane said that as consumers become accustomed to seeing higher prices on supermarket shelves, they will adjust.

"Just like a gallon of gas, it becomes the new price and people get begrudgingly used to it," he said.

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No Surprise from the Fed

by Dante DeAntonio, Director – Moody's Analytics – Mar. 21, 2024

An **upbeat**, if still **cautious**, tone characterized the March meeting of the **Fed**eral Open Market Committee. The **fed funds rate target**, as anticipated, was kept **unchanged**, despite higher-than-expected consumer price inflation reports in recent months. However, reflecting recent communications, the **Fed**eral Reserve **dampened expectations** about the FOMC's urgency to **rush to rate cuts**.

The **committee's latest Summary of Economic Projections suggests** that **2024 will see 75 basis points' worth of cuts to** the **fed funds rate**, **unchanged from** the most recent Summary of Economic **Projections from December**. This reflects policymakers' continued confidence that policy tightening has worked and inflation will eventually return to target. However, the committee reiterated that it will not be appropriate to reduce the target range until it has gained greater confidence that inflation is moving sustainably toward 2%

Notably, though, policymakers are now more upbeat about a soft landing than they were in December. The FOMC's GDP forecast for 2024 was revised upward from 1.4% to 2.1%. Subsequently, the Fed predicts 2% growth for 2025 and 2026, up slightly from December without comparable changes to inflation and unemployment projections.

Inflation has receded meaningfully in the U.S. without the corresponding increase in joblessness historically observed when restrictive policy is needed to bring down inflation. However, early inflation readings in January and February came in higher than expected, owing to a large degree to sticky shelter inflation. As Fed Chair Jerome Powell reiterated, the Fed will need to see a few more reports to convince itself that inflation is on a sustainable trend back to target. This renders a May cut unlikely, given a limited number of outstanding inflation reports before then.

The labor market is still threatening to stall progress on inflation. Wage growth is a sizable margin above the level the Fed estimates as compatible with its inflation target. January and February payroll hiring accelerated from late 2023, and at 3.9%, the unemployment rate signals the U.S. labor market is unlikely to have come fully into balance

Our latest baseline forecast puts the first interest rate cut in June. In total, we expect a 75-basis point reduction by the end of 2024. We expect policy is loosened gradually and that the Fed's main policy rate remains restrictive through mid-2026.

CHIPS Act Awards Ramp Up

Federal subsidies to boost semiconductor production in the U.S. are accelerating. In December, U.S. Commerce Secretary Gina Raimondo said she expects to make around a dozen semiconductor chips funding awards within the next year under the CHIPS Act of 2022, some of them multibillion-dollar announcements. This prediction is coming true.

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On Tuesday, the White House announced the biggest award yet, approximately $8.5 billion in direct subsidies to Intel along with up to $11 billion in loans. The company had previously announced that it expects to spend upward of $100 billion on U.S. facilities and research programs in Arizona, Ohio, New Mexico and Oregon. Two new facilities just outside Columbus OH will be part of a complex that could ultimately be among the largest chipmaking centers in the world.

Initial CHIPS Act payouts were slow in coming and relatively small. Now the pace is accelerating. On February 19, the Commerce Department announced a large award of $1.5 billion to GlobalFoundries to subsidize three projects. The bulk of the award is for construction of a new plant on the company's Malta NY site, which will make chips for applications in automotive, aerospace, defense and artificial intelligence.

A smaller part of the award is for expansion of the company's existing Malta facility by adding new technologies already in use in GlobalFoundries' Singapore and Germany facilities, which supply the auto industry. The third project is to upgrade and expand capacity in the company's facility in Essex Junction VT, creating the first U.S. facility for high-volume production of gallium nitride semiconductors used in electric vehicles, power grids, data centers, and 5G and 6G smartphones.

The GlobalFoundries award is significant because the company is the only U.S.-based "pure-play" foundry. In other words, it makes chips based on users' specifications, making it a competitor to Taiwan-based TSMC, albeit much smaller. Although GlobalFoundries is U.S.-based, it also has facilities in Europe and opened one in Singapore in September

The incentives to the company improve the prospects for domestic chip security in two ways: First, the better cost1effectiveness encourages the company to locate its next plant domestically. Second, as a competitor to TSMC, the company can potentially compete to supply some of TSMC's biggest U.S. customers, notably Apple and Nvidia.

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Oregon Loses Jobs for the First Time Since 2021

Mike Rogoway – Oregonian –

Oregon's spectacular rebound from the pandemic recession may be coming to an end.

In January, the state posted a **net loss in jobs compared** to a **year earlier** – the first time that has happened since 2021. And the **unemployment rate climbed above 4%** for the first time in more than a year.

This isn't a recession. Far from it.

Wages continue climbing and Oregon's labor market remains tight, by historical standards. Employers say it's still very hard to find workers.

Still, it's clear that the robust growth that got underway three years ago, in the wake of COVID-19, is at last winding down.

The **state had 1.97 million jobs in January**, according to the latest seasonally adjusted data from the Oregon Employment Department. That's about **5,000 fewer** jobs **than** it had a **year earlier**.

It's a **tiny decline overall, 0.2% on** an **annual basis**. **But** it's a **sharp contrast** to the **prior three years**, when Oregon was adding several thousand jobs each month as the state roared back from the pandemic.

The slowdown isn't a big surprise. **Oregon's workforce had regained** all the **jobs** it **lost to** the **pandemic by** the **start of last year** and, with the **state's population stagnant**, Oregon simply doesn't have more people to fill job openings.

Oregon's slight decline in employment compares to 1.9% job growth nationally over the last 12 months. Employment department economist Gail Krumenauer notes in a new report that Oregon's slowdowns came mostly in the latter part of the year.

Manufacturing was among Oregon's weakest sectors last year, according to Krumenauer, declining by 3.4%. The state's factories began shedding jobs in 2022 and continued their downward trajectory through most of last year.

Blame the semiconductor industry for much of that decline. Chipmakers pulled back last year from three years of outstanding growth. Economists are expecting better results over the next few years as factory upgrades get underway at Intel and other large Oregon chip factories.

In 2023, Oregon also shed jobs in retail – a sector that never fully recovered from the pandemic – and posted declines in categories that include building maintenance and call centers.

Oregon's biggest gains, Krumenauer found, were in health care, local government and hospitality jobs. Construction, which had appeared to be a standout sector last year, actually grew little over the past 18 months, according to newly revised state data.

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State economists expect Oregon will resume adding jobs this year, growing by almost 16,000 positions over the next year. Krumenauer notes that works out to about 1% annual growth, anemic by recent standards but suggestive of a state economy that is solid, though no longer spectacular.

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Export Fight Risks Natural-Gas Swings

by David Uberti and Ryan Dezember – WSJ – Feb. 2, 2024

Americans' utility bills are getting wrapped up in the fight over President Biden's **pause** on most **new natural-gas exports**.

The White House last month effectively froze new approvals for liquefied natural gas shipments, a booming industry that helped turn the U.S. into an energy-export powerhouse. While environmentalists are urging officials to scrutinize projects' impact on the climate, producers warn the pause could hurt the country's ability to supply allies with fuel in the future.

Now, Americans' power and heating costs are becoming a growing part of the tug of war.

As the Energy Department weighs new criteria for greenlighting future exports, **some manufacturing groups and consumer advocates warn that America's ties to global markets could make price instability more** likely. The **fear** is that additional projects in the next decade **could push up Americans' heat and power bills**, **as well as costs to make everything from drywall to steel**.

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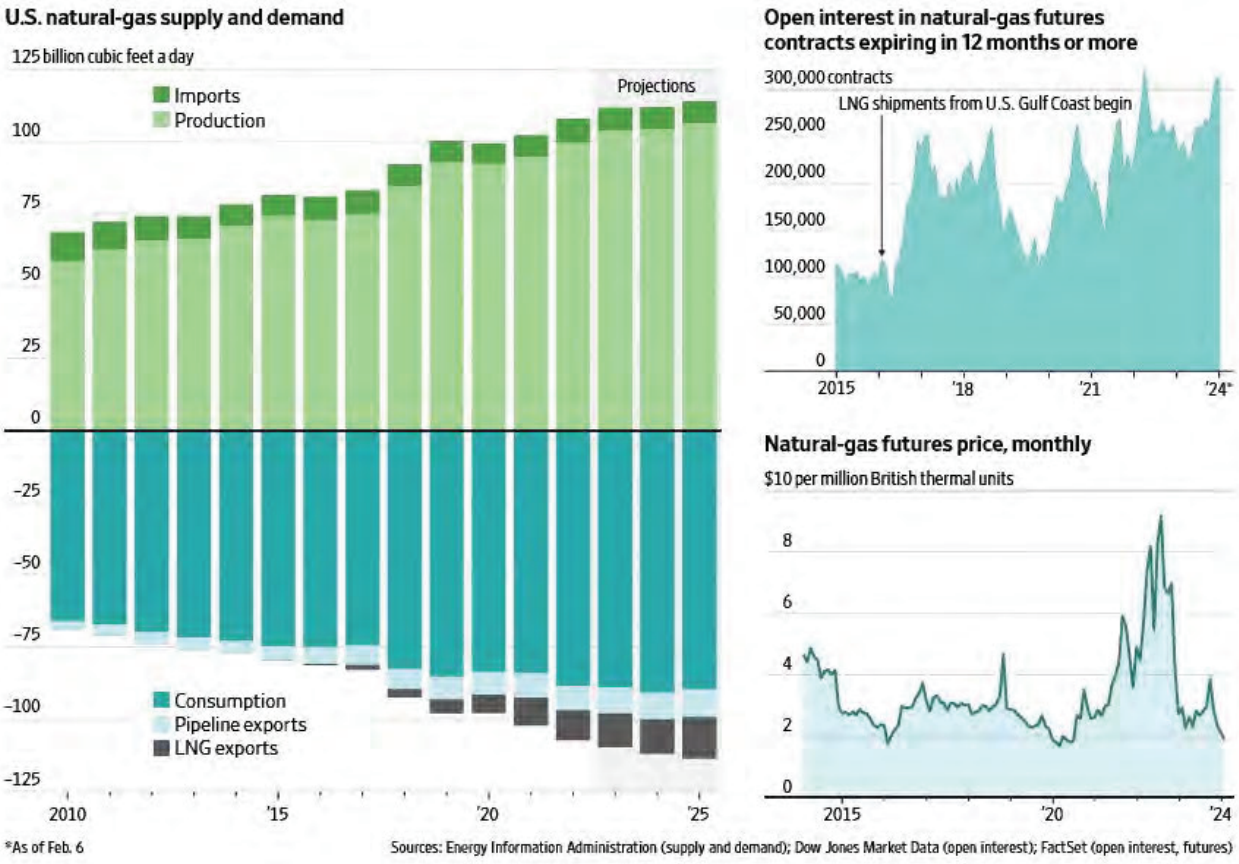

At a Senate hearing Thursday, Deputy Energy Secretary David Turk said the administration aims to preserve the country's cheap gas. "That is a huge economic advantage," he said. "Do we want to give that up as a country? Again, we need to analyze that."

The **domestic impact of LNG exports** has been hotly contested since the country began funneling more gas-laden tankers to foreign buyers in 2016. While record production has largely kept U.S. costs low, international shocks in recent years have helped whipsaw prices to shale-era highs and have contributed to some of the most volatile periods in decades.

Thanks to warm weather and roaring production in Texas and Appalachia, benchmark U.S. gas prices this week fell to their lowest levels since the depths of the pandemic, closing Friday at $1.847 per million British thermal units.

But traders are betting on a rally sparked by projects currently under construction, which will allow more gas to flow to businesses across Europe and fast-growing economies in Asia. On Friday, some futures contracts for delivery in 2027 and 2028 traded for more than $4.50.

"Consumers can afford [$4 gas]," said Aubrey Hilliard, president of Texican Natural Gas's Carolinas division. "What they don't want is spikes to $9."

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To limit that risk, Hilliard's company is advising customers such as glassmakers and cement producers to lock in supplies further toward 2030. The number of outstanding contracts for deliveries 12 months or more into the future has climbed as additional export terminals in Texas and Louisiana prepare to come online, according to Dow Jones Market Data.

The U.S. is already the world's largest exporter of natural gas. Traders last year sent roughly 11% of the country's production overseas, according to the Energy Information Administration. Analysts project that share could roughly double by the end of the decade and climb higher in the 2030s depending on how many proposals pan out.

Biden's pause on new exports to countries without free-trade agreements keys in on that future wave of projects. Still, industry groups warn the freeze is chilling investment and creating uncertainty for allies that turned stateside for gas after Russia's war on Ukraine set off an economic conflict between the Kremlin and the West.

In defending the climate effects of LNG, companies are highlighting the potential of gas to supplant coal worldwide.

Toby Rice, chief executive of EQT, a top producer, told lawmakers Tuesday that tapping deeper into the global market will push firms to pump more natural gas that can be redirected around the U.S. as needed. Surplus gas is the best defense against foreign shocks, Rice said, adding, "Exports are the only reason for us to create that surplus."

Australia served up a cautionary tale for exporters **during** a **2017 heat wave**, when **foreign shipments totaling** more than **60% of production failed** to **leave enough gas at home** to **prevent prices from surging**. Aluminum smelters cut output. Fishermen watched catches rot during blackouts.

Fears of a similar crunch in the **U.S.** didn't bear out until a string of weather events in 2021 sent prices skyrocketing.

A **deep freeze** in **Texas** in **February 2021** boosted demand and clogged wells with ice. After Americans and Europeans cranked up their air conditioners during a **sweltering summer**, **Hurricane Ida forced** nearly all of the **Gulf** of Mexico's **gas output offline**.

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Water Utility National Equity Return Average Trends Up Slightly in 2023

by Heike Doerr – Regulatory Research Associates (RRA)
an affiliate of Standard and Poor's Global Market Intelligence – Feb 20, 2024

Nationwide, the latest activity with respect to water utility equity returns occurred in July 2023, when cost-of-capital changes were approved for the four largest California

investor-owned water utilities under the state's semi-automatic adjustment process. No water utility base rate cases were completed in July or August.

- The return on equity (**ROE**) **approved** for **water utilities nationwide** in **cases decided** during **2023** was **9.64%**. The base rate proceedings spanned nine states, with cost-of-capital parameters provided in seven proceedings, **ranging** from **8.7%** in **Connecticut** to **9.8%** in **North Carolina**. In **2022**, 10 water utility rate cases were completed nationwide, with an average ROE of **9.61%**.
- The **four cost-of-capital proceedings** completed in **California** incorporated the companies' **water cost-of-capital mechanism** (**WCCM**), which resulted in ROEs ranging from 9.31% to 9.8%. A subsequent increase tied to the WCCM, approved in November 2023 and effective Jan. 1, 2024, **increased ROEs by** an additional **70 basis points**.
- **Authorized ROEs for water utilities** are **in line with** the **gas utility average** and **remain above** that of **distribution-only electric utilities**.

Regulatory Research Associates evaluates water utility regulation in more than 20 state jurisdictions and monitors rate proceedings involving rate change requests of at least $1.0 million for the 12 largest investor-owned and privately held water utilities.

For additional details regarding water utility rate cases from Jan. 1, 2010, through Dec. 31, 2023, please refer to this industry document.

2023 rate case highlights

Connecticut – A litigated decision for Eversource Energy subsidiary Aquarion Water Co. of Connecticut Inc. included an 8.7% return on equity, the lowest nonpunitive return authorized for a water utility since 2010, as tracked by RRA. While ROEs authorized in Connecticut have historically been below the prevailing industry average, this return is considerably below the national average. On Eversource Energy's recent earnings call with investors, the company expressed an interest in selling its water business, which is over 90% in Connecticut.

California – ROE determinations for the state's energy and water utilities occur outside of general rate cases in cost-of-capital proceedings, usually conducted every three years. The class A water utilities are divided into two groups by size for cost-of-capital proceedings. At the June 29, 2023, California Public Utilities Commission meeting, the commission approved a proposed decision that laid out recommendations for the state's four largest investor-owned water utilities' ratemaking returns and capital structures through 2024.

The authorized returns for American Water Works Co. Inc. subsidiary California-American Water Co., California Water Service Group subsidiary California Water Service Co., American States Water Co. subsidiary Golden State Water Co., and SJW Group subsidiary San Jose Water Co. ranged from 9.31% to 9.8%, which included 50 basis points or so of benefit from the continued use of the WCCM.

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In November 2023, the PUC approved the companies' advice letters based on the movement of the bond index underlying the WCCM. For additional details, refer to "Equity returns of California's largest energy, water utilities to bump up Jan. 1"

North Carolina – In June 2023, the North Carolina Utilities Commission authorized Essential Utilities Inc. subsidiary Aqua North Carolina, Inc. a 9.8% ROE following a decision in Corix Regulated Utilities (Us) Inc. subsidiary Carolina Water Service Inc. of North Carolina's base rate proceeding that utilized the same ROE. Neither decision was unanimous. The dissenting commissioners expressed concern that the ROE was too high, given "the reduced risk to shareholders" that stemmed from using a multiyear, forward-looking approach rather than a historical test year.

As a result of multiyear, performance-based rate plans being implemented, RRA raised its ranking of the North Carolina regulatory environment to Average/2 from Average/3 rating as it pertains to water utility regulation.

2023 Water utility rate case decisions

Order date	Company	State	Case type	ROR (%)	ROE (%)	Common equity as % of capital	Rate base ($M)	Test year end
12/13/23	Aqua Ohio Inc.	Ohio	Base rate case	6.78	9.50	52.10	303	06/30/23
11/15/23	California American Water Co.	California	Cost of capital	7.69	10.20	57.00	NA	NA
11/15/23	California Water Service Co.	California	Cost of capital	7.46	10.27	52.10	NA	NA
11/15/23	Golden State Water Co.	California	Cost of capital	7.73	10.06	54.55	NA	NA
11/15/23	San Jose Water Co.	California	Cost of capital	7.94	10.01	53.40	NA	NA
06/29/23	California American Water Co.	California	Cost of capital	7.29	9.50	57.04	NA	12/31/22
06/29/23	California Water Co.	California	Cost of capital	7.08	9.57	53.40	NA	12/31/22
06/29/23	Golden State Water Co.	California	Cost of capital	7.36	9.36	57.00	NA	12/31/22
06/29/23	San Jose Water Co.	California	Cost of capital	7.47	9.31	54.55	NA	12/31/22
06/29/23	Golden State Water Co.	California	Base rate case	NA	NA	NA	1,161 (Yr1) 1,260 (Yr2) 1,376 (Yr3)	12/31/22
06/05/23	Aqua North Carolina	North Carolina	Base rate case	6.89	9.80	50.00	353 (Yr1) 380 (Yr2) 401 (Yr3)	12/31/23
04/28/23	Veolia Water Idaho Inc.	Idaho	Base rate case	6.91	9.25	55.57	255	12/31/22
04/26/23	Carolina Water Service Inc. of North Carolina	North Carolina	Base rate case	7.22	9.80	50.00	151	03/31/24
04/24/23	Virginia American Water Co.	Virginia	Base rate case	6.29	9.70	40.73	NA	04/30/23
04/12/23	Water Service Corp. of Kentucky	Kentucky	Base rate case	7.07	9.55	50.09	6	12/31/23
03/15/23	Aquarion Water Co. of Connecticut	Connecticut	Base rate case	6.46	8.70	50.35	992	08/31/22
01/12/23	The York Water Co.	Pennsylvania	Base rate case	NA	NA	NA	NA	02/29/24
	Average rate award			**7.17**	**9.64**	**52.53**		

As of Feb. 15, 2024.
NA = not available; Yr = Year.
ROR = Return on rate base; ROE = Return on equity.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights
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ROE trends compared to electric and gas utilities

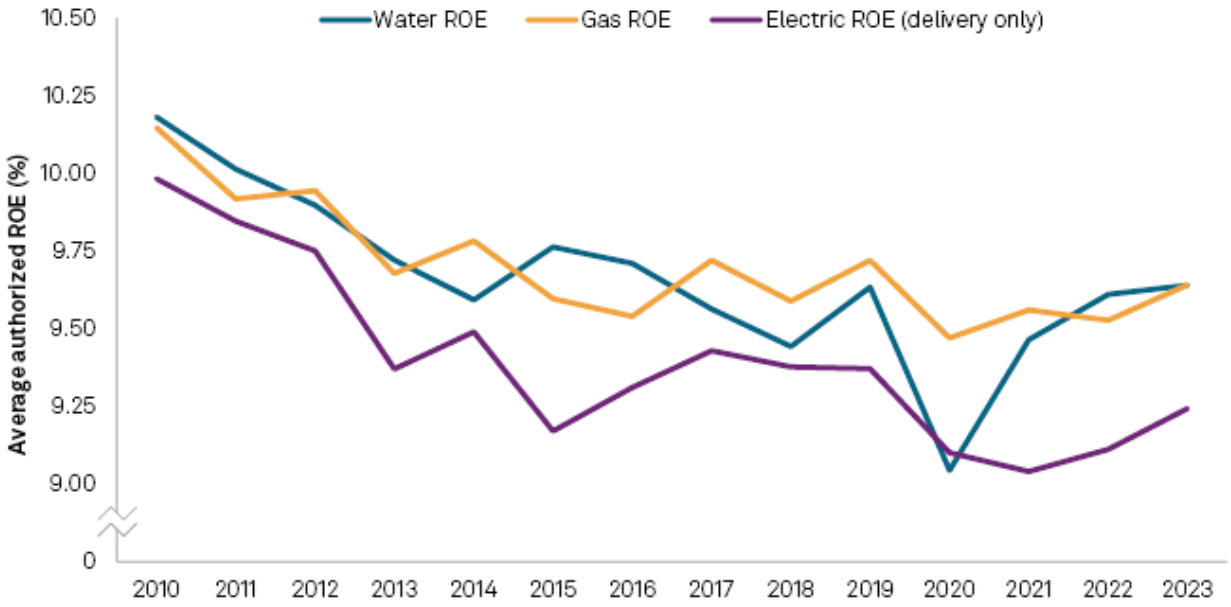
While the pace of rate case activity reached record levels across energy utilities, the number of base rate cases completed across the small water utility sector remained comparable to recent years.

The average ROE authorized for distribution-only electric utilities was 9.24% for cases decided during 2023 versus the 9.11% average observed in 2022. RRA's calculations relied on 12 distribution-only electric rate case decisions that included an ROE determination during 2023 versus nine in 2022.

The **average ROE authorized** for **gas utilities** was **9.64%** for **cases decided** during **2023 versus** the **9.53%** average observed in **2022**. RRA's calculations relied on 43 gas rate case decisions that included an ROE determination during 2023 versus 33 in 2022.

For additional details on electric and gas utility ROE trends, refer to "Energy authorized returns up modestly as rate case activity soared in 2023."

Average electric, gas and water authorized ROEs



As of Feb. 20, 2024.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.
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CenterPoint to Sell Gas Distribution Assets in Louisiana, Mississippi for $1.2B

by Nephele Kirong
Standard and Poor's Global Market Intelligence – Feb. 20, 2024

CenterPoint Energy Inc.has reached a **deal** to **sell** its **natural gas distribution operations** in **Louisiana and Mississippi** for **$1.2 billion to Bernhard Capital Partners Management** LP's **Delta Utilities**.

The assets covered by this transaction include approximately 12,000 miles of main pipeline serving approximately 380,000 customers. The price tag represents approximately 32 multiple of the two local distribution companies' (LDCs) earnings in 2023, CenterPoint said in a Feb. 20 news release announcing the transaction.

The anticipated $1 billion in after-tax proceeds will be recycled into service territory where **CenterPoint has both electric** and **natural gas operations** or where it has a larger presence "at a valuation that is more efficient than issuing common equity," President and CEO Jason Wells said.

"The sale will also enable us to redeploy approximately $1 billion of future capital expenditures intended for Louisiana and Mississippi into jurisdictions with less regulatory lag, thereby enhancing the ongoing earnings power of the company," Wells added. LDCs in the two states represent less than 4% of the company's overall rate base.

In **January 2022**, **CenterPoint closed** the **$2.15 billion sale** of its **Arkansas and Oklahoma gas utilities to Summit Utilities** Inc. **CenterPoint continues** to **hold natural gas utilities** in **Indiana**, **Minnesota**, **Ohio and Texas**. It also **has electric utilities** in **Indiana and Texas**.

For **Bernhard** Capital Partners, this newly announced transaction **builds upon** its previously announced **acquisition of Entergy** Corp.'s **natural gas distribution businesses** in **Louisiana**. "**Once both transactions** are **complete**, **Delta** Utilities will be a **leading natural gas utility** in **Louisiana and Mississippi** and among the top 40 providers in the United States," Jeff Jenkins, founder and partner at Bernhard Capital Partners, said in a separate statement.

The **CenterPoint transaction** is **expected** to **close** toward the end of the **first quarter** of **2025**, **subject to** customary closing conditions, including antitrust clearance and **state regulatory approvals**.

Morgan Stanley & Co. LLC and Wells Fargo Securities LLC were CenterPoint's financial advisers, and Latham and Watkins LLP, Phelps Dunbar LLP and Brunini Grantham Grower & Hewes PLLC were its legal advisers.

Jefferies LLC was lead financial adviser to Bernhard Capital, with Scotiabank also as financial adviser and Kirkland & Ellis LLP as legal adviser. Jefferies LLC and

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Scotiabank provided a debt financing commitment to Bernhard Capital in connection with the transaction.

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Southwest Gas Holdings Reorganizes Centuri Ahead of Separation

by Noah Schwartz
Standard and Poor's Global Market Intelligence – Feb. 29, 2024

Southwest Gas Holdings Inc. is **restructuring Centuri** Group Inc. as the utility operator moves ahead with **plans** to **separate** the **utility infrastructure services unit** and operate **as** a **standalone natural gas company**, Southwest Gas executives said on a Feb. 28 earnings call.

The plan to offboard Centuri remains "on track," Southwest Gas CEO and President Karen Haller said. In December 2023, Southwest Gas brought in William Ferhman, the former president and CEO of Berkshire Hathaway Energy, to lead Centuri through the separation process.

Ferhman is prioritizing cost-cutting and reorganization as Centuri works toward independence from the parent company, executives said. The Las Vegas-based gas distributor **did not provide** a **timeline** of when the **Centuri separation** will take place.

"We're focused on reducing costs across all facets of the business, starting with sales, general and administrative expenses," Ferhman said. "I have eliminated two corporate leadership levels, which allows me to get very close to our operating businesses. Each of our business unit presidents now report directly to me."

The restructuring is intended to "streamline our cost structure and implement a disciplined accountability model," Ferhman continued, adding that the company plans to focus its maintenance and growth capital spending on the business lines that are "the most profitable and well run."

The **plan to spin off Centuri** hit a **snag** in **November 2023** when the **US I**nternal **R**evenue **S**ervice **declined** to **rule** on **whether** the **spinoff would qualify for tax-free status**. In an earnings presentation, the company said it will "continue to assess the attractiveness of a tax-free separation of Centuri (either following an IPO or in lieu of an IPO) against other taxable alternatives."

Southwest Gas has submitted a draft registration statement for a potential IPO, according to the investor presentation.

"I have been in this role for about a month so that work is just now beginning and will be more clearly articulated as we go through the IPO process here in a few weeks," Ferhman said on the separation process.

Haller indicated the **strategy for spinning off Centuri remains dependent** on **external factors**. "Following execution of expected IPO, Southwest Gas Holdings may ultimately separate the business through a series of sell-downs, or share exchanges, or

depending on market conditions, we could distribute the balance of Centuri shares to Southwest Gas Holdings shareholders through a spin," Haller said during the call.

Investor pressure

Activist investor Carl Icahn, who **became Southwest Gas' top shareholder** in **June 2023**, has **been applying pressure** on the company to cut costs and improve value for shareholders.

In **2021**, **Icahn vigorously opposed Southwest Gas' acquisition** of **Dominion** Energy Inc.**'s Questar Pipeline** Co. The move "will make all past errors pale in comparison," Icahn wrote on the then-rumored deal in a letter to the Southwest Gas board. Icahn then launched an attempted bid to take over Southwest Gas and stop the acquisition.

Despite Icahn's opposition, **Southwest Gas closed** on the nearly **$2 billion deal** in **December 2021**. In **February 2023**, **Southwest Gas completed** the **sale** of **Questar** – which had been **renamed MountainWest Pipeline** LLC – **to Williams** Cos. Inc. **for $1.5 billion**. Icahn supported both the MountainWest divestiture and the spinoff of Centuri.

Southwest Gas reported full-year 2023 adjusted net income of $238.4 million, or $3.36 per share, compared to $196.6 million and $3.00 per share in 2022. For the fourth quarter, the company reported adjusted net income of $81.2 million, or $1.13 per share, compared to $78 million and $1.16 per share in the year-ago quarter.

The company attributed its 2023 growth to a $107 million increase in operating margin from 2022. Executives said the jump in operating margin was fueled by a $53.8 million rate increase in its Arizona service territory that took effect in February 2023.

For 2024, the company issued net income guidance for its gas segment of $228 million to $238 million.

Haller said two pending rate cases will "provide the opportunity to start recovering the significant investments we have made to serve our customers." The company expects a decision on a $70 million rate case in Nevada in the spring and a separate $16 million rate case for its interstate pipeline affiliate, Great Basin Gas Transmission Gas Co., to be completed in the first week of March.

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Utah Governor Names Telecom Vet to State Utility Commission

by Jason Lehmann – Regulatory Research Associates (RRA)
an Affiliate of Standard and Poor's Global Market Intelligence – Mar. 28, 2024

Utah Gov. Spencer Cox has **named Jerry Fenn**, a **Republican**, **to** a position on the three-seat **Public Service Commission** of Utah, to fill the remainder of a term expiring March 1, 2027.

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- Utah Public Service Commission (PSC) members are appointed by the governor and subject to state Senate confirmation, generally for six-year terms. The chairperson may serve an indefinite term in office. No more than two commissioners may serve from the same political party.
- The **PSC** is **awaiting** a **major electric rate case filing from PacifiCorp** and is also considering a settlement recently filed in **Dominion** Energy Inc.'s **planned sale** of its **Questar Gas** Co.
- Regulatory Research Associates views the regulatory climate in Utah as somewhat more constructive than average from an investor point of view. The state remains traditionally regulated, and the PSC has been receptive to mergers. There has been little base rate activity in recent years.

Cox submitted Fenn's nomination to the Utah State Senate on March 18 for consideration.

Fenn previously was **president** of **Qwest Communications Utah** and **regional** vice president for **CenturyLink**. Fenn is currently self-employed as an attorney and consultant, and is an **adjunct professor** at **Brigham Young University**. He received a **bachelor's** degree in **economics**, a **master's** degree in **business administration** and his **juris doctorate** from **BYU**.

If confirmed, Fenn would **replace** former PSC Commissioner **Thad Levar**, who appears to have departed the PSC in early January. Levar, a Republican, was appointed to the PSC for a new term in 2021.

The **other members** of the **PSC** are **David Clark**, a **Republican** serving a term extending to March 2025, and **John Harvey**, who joined the PSC in June 2023 for a term expiring in March 2029.

Dominion and Berkshire Hathaway Energy **PacifiCorp** are the **state's major utility** operating **companies**.

The PSC is considering a settlement submitted earlier this month by Dominion, Enbridge Inc. and intervenors in the companies' merger proceeding before the PSC. Under the deal, announced in September 2023, **Dominion** is **selling Questar and other gas utility businesses** in **Ohio** and **North Carolina** and **other assets to Enbridge**.

In the coming weeks, the PSC will also begin adjudicating a planned PacifiCorp electric rate case application (Docket No. 24-035-04). **PacifiCorp proposes** implementing **new electric rates**, subject to commission authorization, on **Jan. 1, 2025.** The company's **last base rate change** took effect in **January 2021** after the commission authorized a $31.4 million electric base rate increase in Docket No. 20-035-04.

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Muldoon/39

PacifiCorp sought a test period determination before filing the general rate case application, proposing a future test period for the 2024 rate case that uses the 12 months ending Dec. 31, 2025, with a 13-month average rate base. The Utah Division of Public Utilities did not oppose the proposal, and on March 11, 2024, the PSC issued an order approving it.

RRA view of Utah regulation

Regulatory Research Associates views the regulatory environment in Utah as somewhat more constructive than average from an investor point of view. The state remains traditionally regulated, and the PSC has been receptive to mergers. There has been little base rate activity in recent years; many prior proceedings had been resolved through settlement agreements, which had sometimes included multiyear rate adjustments.

The PSC's last rate case decision was issued in December 2022 when it authorized Dominion Energy Inc.'s Questar Gas Co. a $47.8 million gas distribution rate increase in Docket No. 22-057-03, effective Jan. 1, 2023. The authorized rate hike was premised upon a 9.6% return on equity (51% of capital) and a 6.856% return on an average rate base. The authorized return on equity (ROE) at the time was above the 9.42% average ROE accorded to gas utilities through the first nine months of 2022. The **average gas ROE authorized** in **2023** was **9.53%.**

–

WY Consumer Advocate Seeks Additional Conditions In Enbridge-Dominion Deal

by Monica Hlinka – Standard and Poor's Global Market Intelligence – Apr. 8, 2024

In **Enbridge** Inc.'s pursuit of **acquiring Dominion** Energy Inc.'s **gas utility businesses in Wyoming**, the **Office** of **Consumer Advocate offered** up **additional commitments** that should be **considered before** the **Wyoming P**ublic **S**ervice **C**ommission **issues** a **decision on** the **transaction**. (Docket No. 30010-218-GA-23)

- The Office of Consumer Advocate (**OCA**) filed **testimony** with the commission April 5 in **Enbridge's proposed acquisition** of **Questar Gas** Co. Overall, the OCA supports the deal on the condition that additional commitments are secured.
- The recommended commitments relate to **enhanced ring-fencing measures**, implementing a **cost allocation manual** and a **new low-income assistance** program. The OCA reiterated that the acquisition hinges on its alignment with the public interest and the assurance of the continued provision of safe, reliable natural gas service at reasonable rates.
- Under the deal, announced in September 2023, **Dominion would sell Questar and gas utility businesses in Ohio and North Carolina and other assets to Enbridge**. The sale is **expected** to **close in 2024**, assuming the requisite state and federal approvals are obtained.

➤ In its review, the PSC will examine the proposed deal to ensure that any reorganization resulting from the proposed transaction does not compromise Questar's capacity or ability to serve the public by delivering safe, dependable and reasonably priced natural gas service to its customers.

A prehearing conference is scheduled for May 9, and a two-day public hearing is set to begin May 23.

Questar Gas serves approximately 1.2 million customers **in Idaho**, **Utah and Wyoming**. The **acquisition also requires** approval from the **P**ublic **S**ervice **C**ommission of **Utah** (Docket No. 23-05-16). **While Questar Gas also operates** in **Idaho**, the **I**daho **P**ublic **U**tilities **C**ommission **does not have authority over** the **sale** of **gas utilities at** the **holding company level**.

Regulatory Research Associates views the Wyoming regulatory climate as relatively balanced from an investor point of view, according the jurisdiction an Average/2 ranking.

State law says the Wyoming PSC "shall not approve any proposed reorganization if the commission finds ... that the reorganization will adversely affect the utility's ability to serve the public." The law defines a reorganization as any transaction that results in a change in the majority ownership interest or control of a public utility or the majority ownership interest or control of any entity that owns a majority interest in or controls a public utility.

The commission requires several provisions to be included in an application, such as the utility's financial condition and the proposed transaction's effect on the utility's ability to provide service and on any other utility. There is no statutory time frame within which the PSC is required to render a decision regarding a proposed merger.

OCA recommendations

In its testimony, the OCA said the commitments offered in the initial application "are commendable ... it is imperative to introduce additional conditions and safeguards to ensure that the proposed merger is in alignment with the public interest."

Further, the OCA supports the approval of the acquisition, contingent upon the inclusion of the additional protections.

The **OCA requests** to **cap operating, maintenance, administrative and general expenses per customer for** the **12 months ended December 2023**, which is set at $180.98, **thereby capping** the **amount Questar could seek to recover** in its **next general rate case**. The OCA said this commitment would provide rate stability and facilitate Questar's integration with Enbridge without putting undue financial burden on Wyoming ratepayers.

The OCA also advocated for **further ring-fencing provisions** to **shield Questar from** the **potential adverse effects** of **Enbridge's lower credit rating**. As of March 29, Questar had a higher credit rating than Enbridge from two of the three rating

agencies, and therefore, the OCA said it is "important to safeguard Wyoming ratepayers from any adverse effects that may arise from a possible credit downgrade associated with the proposed merger."

The consumer advocate recommended a commitment that would require Questar, in its **next general rate case**, to **demonstrate** that its **requested cost of debt is not higher than** what **would have been incurred had** the **merger not occurred**. "This would entail [Questar] **utilizing** its **current credit rating as** a **benchmark unless** it **can substantiate any downgrade** resulting **from market forces beyond its control**," the OCA said.

In the **company's most recent Wyoming**-jurisdictional **rate case decision** issued Nov. 7, 2023, the **PSC approved** a settlement authorizing a **r**eturn **o**n **e**quity of **9.65%,** a long-term debt cost of 4.07%, and a **capital structure** of **51.56% equity** and 48.44% long-term debt. This results in an **overall rate of return** of **6.95%**.

The OCA said it is "crucial" for the parties to secure a commitment for a **comprehensive cost allocation manual** for services Enbridge provides to Questar. The consumer advocate noted that in Dominion's purchase of Questar in 2016, the approved settlement called for establishing a cost allocation manual outlining the precise methodology for assigning Dominion corporate services costs to Wyoming ratepayers. However, during Questar's most recent gas rate case, the OCA observed "that some progress has been made in presenting a comprehensive, Wyoming-specific cost allocation manual." The OCA said further work is necessary to "ensure accuracy and completeness in cost allocation to Wyoming and other entities within Enbridge."

In its initial application, **Enbridge committed** to "**transparently reporting all costs** and **investments** in its financial reports, including those directly assigned or allocated from another Enbridge subsidiary." The application also said the company agreed to maintain an **audit trail** to specifically identify allocable costs.

The **OCA noted** that on March **22**, **Enbridge reported** having **439 subsidiaries**. With such an extensive corporate structure, the OCA said it is "imperative" to have a complete and comprehensive cost allocation manual, and securing this commitment would "offer a suitable mechanism for tracking and auditing costs assigned to Wyoming ratepayers."

The OCA also requests a formal commitment by the companies to formalize **affiliate transaction reporting requirements**, which can provide information necessary to ensure Wyoming ratepayers receive the least-cost and least-risk service options.

Regarding Wexpro Co. and related entities, hedging policies and gas prices, the OCA is seeking a commitment from Questar to a meeting to review its forecast sources and pricing of natural gas following the issuance of an integrated resource plan and before the subsequent request for proposal process.

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According to the OCA, Enbridge and Questar have outlined plans to invest roughly $4.6 million annually in capital expenditures in Wyoming from 2023 through 2027. These investments will support the maintenance and upkeep of Questar's natural gas delivery system in the state.

Regarding the potential implementation of clean energy projects, such as renewable natural gas, hydrogen and compressed natural gas, the OCA seeks a commitment from the companies that these initiatives must be proven to be the least costly and least risky option.

The OCA recommends that the commission direct Questar to engage in discussions with the OCA and commission staff to explore the potential establishment of a **low-income assistance program** for vulnerable ratepayers in **Wyoming**. Additionally, the OCA requests that shareholders commit $50,000 to initiate the program and consider allocating a portion of future charitable donations to Wyoming toward sustaining the program.

Overview of Questar's portion of transaction

On Sept. 5, 2023, **Dominion** announced its **plan** to **sell** its gas **utilities** – The **East Ohio Gas** Co., **Public Service Co**. of **North Carolina** Inc. (**PSNC**) and **Questar Gas** Co. – **to Enbridge for $9.4 billion** in **cash plus** the **assumption** of **$4.6 billion** of **debt**. **Enbridge** will **also acquire Wexpro** Co., **which develops and produces gas reserves**, **from Dominion**.

Enbridge will **pay** roughly **$3 billion** in **cash** and **assume debt** worth **$1.3 billion to acquire Questar** Gas from **Dominion**. The base purchase price is subject to adjustments for cash, indebtedness, working capital and capital expenditures, and any new regulatory assets and liabilities of Questar Gas arising between July 1, 2023, and the transaction's closing.

Following the announcement, **Questar** submitted an application to the Utah and Wyoming utility commissions seeking approval for a proposed corporate reorganization in which the company **would become** a **subsidiary** of **Fall West Holdco** LLC, a new holding company. The **Utah PSC approved** the **application** Nov. 3, **2023**, while the **Wyoming PSC unanimously approved** the proposed **reorganization** during a Nov. 16, **2023**, public meeting.

Additionally, **Dominion notified** the **Idaho PUC** in Case No. QST-G-23-01 of the **pending** acquisition, as required by a 2016 PUC order approving Dominion's acquisition of Questar **Gas**.

Applications were filed with the Utah PSC and Wyoming PSC on Oct. 20, 2023.

Within the proposed Questar Gas acquisition, **Enbridge Quail Holdings**, which was **created explicitly for** the **sale**, will acquire all of the outstanding equity interests in Fall West Holdco, thereby indirectly acquiring all of the equity interests of Questar Gas, the Wexpro companies, Dominion Gas Project Co. LLC and Questar InfoComm Inc.

Enbridge Quail Holdings commits to honoring all Wexpro agreements, stipulations and associated guideline letters.

The applications outlined various financial, managerial and technical commitments offered by the companies to secure approval for the acquisition.

In Utah, on March 21 Dominion, Enbridge and intervenors in the companies' merger proceeding before the Utah PSC reached a settlement outlining a proposed set of enhanced merger commitments that Enbridge intends to implement upon acquiring Dominion's Questar Gas Co. Surrebuttal testimony in the merger proceeding is due April 8, and an evidentiary hearing will be conducted April 11. If necessary, an additional hearing is reserved for April 12.

Additional related transactions

Regarding the sale of PSNC, **Dominion sought N**orth **C**arolina **U**tilities **C**ommission **approval** of a **proposed reorganization** in which **PSNC** would **become** a **direct subsidiary** of a **new holding company**, **Fall North Carolina Holdco** LLC, which would, **in turn**, be a **wholly owned direct subsidiary** of **Dominion**. The **commission approved** the corporate **reorganization** Nov. 20, **2023**.

Enbridge will **purchase** the **utility from Dominion for $2.2 billion** in **cash plus** the **assumption** of **debt worth $1 billion**.

On Oct. 20, 2023, PSNC and Enbridge filed a joint application with the commission seeking approval of the proposed transaction. Intervenor testimony is due by May 13, and rebuttal testimony is due by May 29. A hearing to receive expert witness testimony regarding the application is scheduled for June 11.

Regarding the **sale** of **East Ohio Gas** Co. **from Dominion**, **Enbridge** will **pay** roughly **$4.3 billion** in **cash** and **assume $2.3 billion** of **debt**. On March 6, the **P**ublic **U**tilities **C**ommission of **Ohio approved** the **transaction** after determining that the deal would not interrupt Dominion Energy Ohio's natural gas service and affirming Enbridge's commitment that it will not recover the transaction costs from customers. The **companies announced** the **completion** of the **sale March 7**.

The **companies** said they **expect** the **deal** to **close** in **2024**, subject to the receipt of several **regulatory approvals**. The expiration or termination of the waiting periods under the **Hart-Scott-Rodino Act** is also required, which occurred Nov. 1, 2023. The companies received final **clearance** from the **Committee** on **Foreign Investment** in the United States on Jan. 11, 2024. The **Federal Communications Commission** must also weigh in regarding the proposed transaction.

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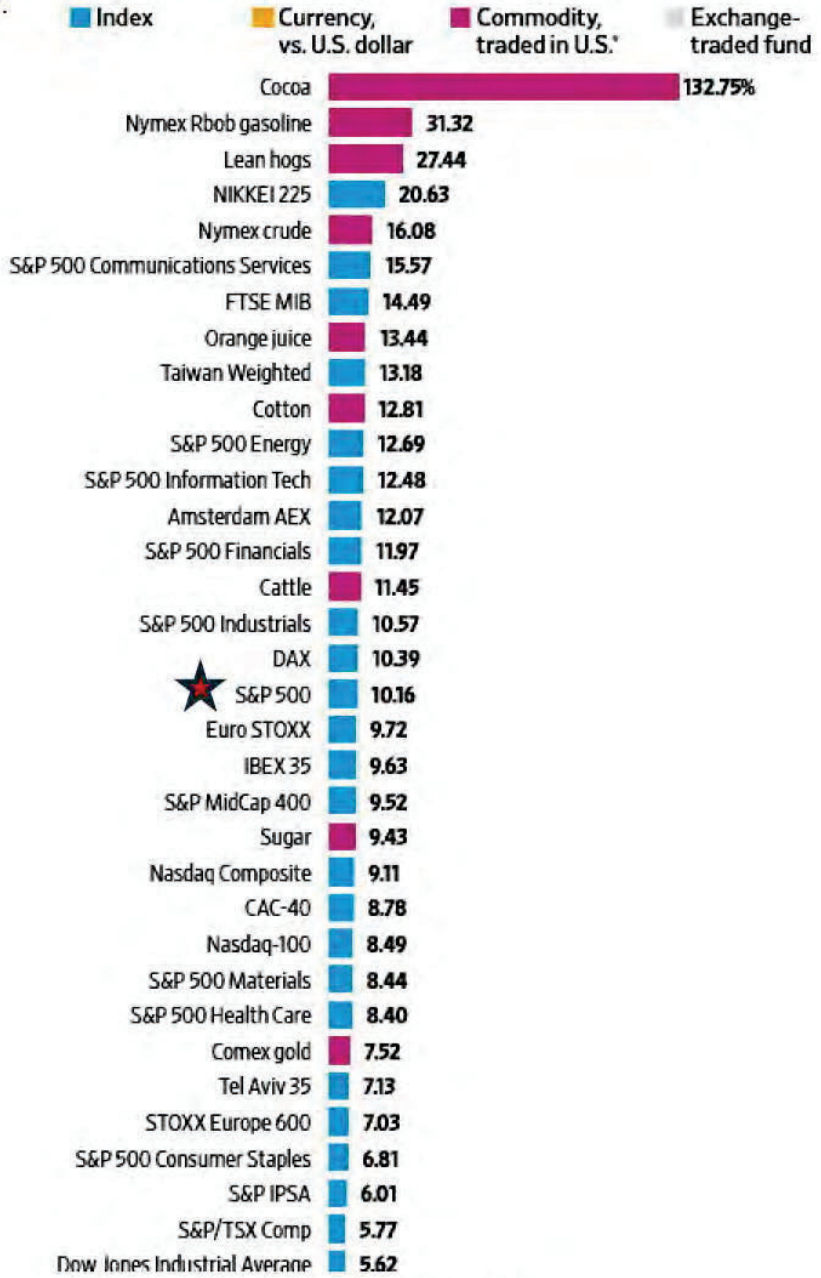
Track the Markets: Quarterly Winners and Losers

WSJ – Apr. 1, 2024

A look at how stock indexes, bond ETFs, currencies and commodities performed for the quarter.



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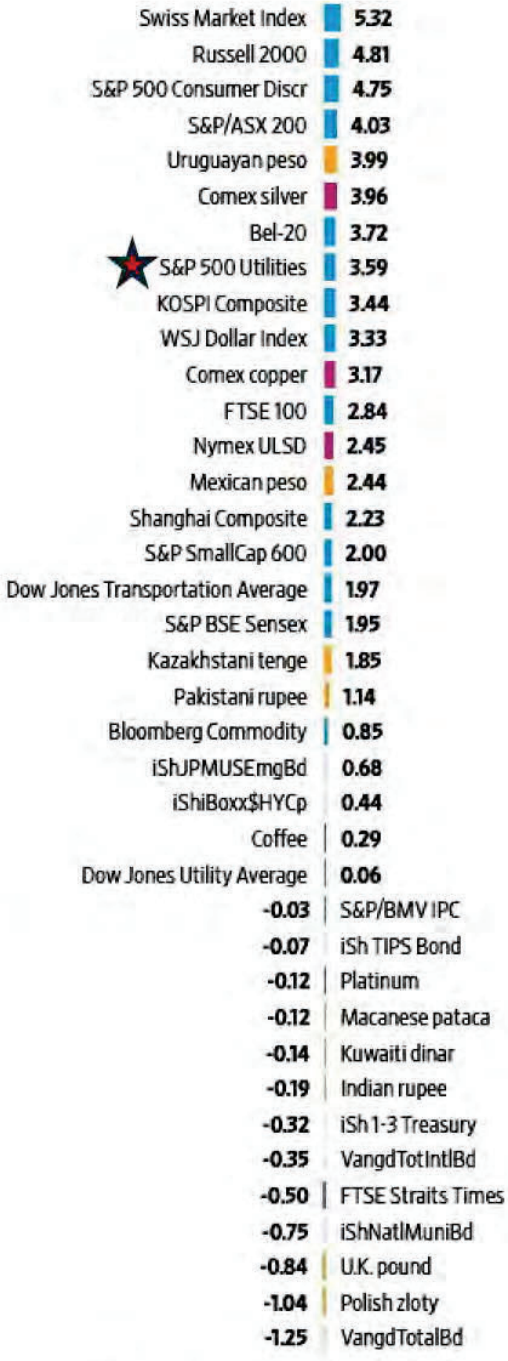

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-0.50	FTSE Straits Times
-0.75	iShNatlMuniBd
-0.84	U.K. pound
-1.04	Polish zloty
-1.25	VangdTotalBd
-1.36	S&P 500 Real Estate
-1.38	Philippine peso
-1.38	DJ Select REIT
-1.50	Chinese yuan
-1.57	iShiBoxx$InvGrdCp
-1.79	iSh 7-10 Treasury
-1.96	Danish krone
-2.13	Romanian new leu
-2.16	Canadian dollar
-2.17	Euro area euro
-2.19	Vietnamese dong
-2.20	Singapore dollar
-2.22	Bulgarian lev
-2.34	Israeli shekel
-2.36	Icelandic krona
-2.74	Malaysian ringgit
-2.80	Ukrainian hryvnia
-2.97	Hang Seng
-3.09	Indonesian rupiah
-3.11	South African rand
-3.24	Brazilian real
-3.85	South Korean won
-3.94	New Taiwan dollar
-4.31	iSh 20+ Treasury
-4.38	Czech koruna
-4.42	Australian dollar
-4.53	Bovespa Index
-4.88	Hungarian forint
-5.25	Swedish krona
-5.33	New Zealand dollar
-5.37	Thai baht
-5.77	Argentine peso
-5.90	Norwegian krone

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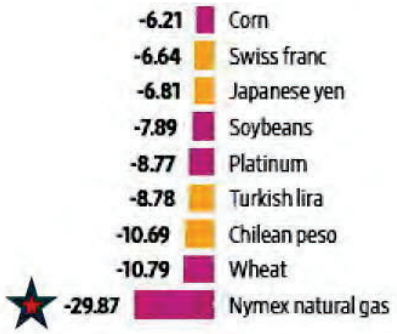

*Continuous front-month contracts
Sources: FactSet (indexes, bond ETFs, commodities), Tullett Prebon (currencies).

CASE: UG 490
WITNESS: Luz Mondragon

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

REDACTED
OPENING TESTIMONY
Revenue Requirement Detail, Expense for Customer Service and Customer Accounts, Excess Deferred Income Tax, Interest Synchronization and Budget to Actual analysis.

April 18, 2024

Docket No: UG 490 Staff/200
Mondragon/1

Q. Please state your name, occupation, and business address.

A. My name is Luz Mondragon. I am a Senior Financial Analyst employed in the Accounting and Finance Section of the Rates, Safety and Utility Performance Program (RSUP) of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/201.

Q. What is the purpose of your testimony?

A. My opening testimony discusses Staff's analysis and position on the following issues:

- Summary of all Test Year adjustments proposed by Staff and the corresponding revenue requirement effect.
- Test Year expenses for Customer Service: Information and Sales Expense (Operations and Maintenance Non-Labor)
- Test Year Excess Deferred Income Tax
- Interest Synchronization analysis.
- Historical Budget to Actuals analysis.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared the following supporting exhibits:

Exhibit Staff/201 ..... Witness Qualifications
Exhibit Staff/202 ……..... Exhibits in Support of Opening Testimony

Q. How is your testimony organized?

A. My testimony is organized as follows:

Introduction 3
Summary of Revenue Requirement 5
Issue 1. Customer Service & Information; Sales Expense O&M Non-Labor 8
Issue 2. Excess Defered Income Tax 16
Issue 3. Interest Synchronization 20
Issue 4. Budget To Actuals 22

Summary……..26

Q. Could there be changes or updates to Staff's position and recommendations?

A. Yes. My testimony represents issues identified to date. My recommendations and issues may change when informed by new data and after reviewing testimony and analysis by other parties.

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Staff/200
Mondragon/3

INTRODUCTION

Q. What is the revenue requirement increase proposed by Northwest Natural (NW Natural or NWN) in this docket?

A. Northwest Natural is proposing an overall increase of $154.9 million, or a base increase of 16.62 percent.[1]

Q. What is the adjustment in revenue requirement recommended by Staff?

A. Staff proposes a reduction the Company's requested revenue requirement increase based on a range of ROE. Figure 1 below shows the reduction from the requested $154.913 million to **[BEGIN CONFIDENTIAL]**

- [redacted]
- [redacted]

[END CONFIDENTIAL].

Q. What adjustments are you proposing to the Company's revenue requirement?

A. I am proposing adjustments to the Company's Customer Service Test Year expenses and Average Rate Adjustment Method of Excess Deferred Income Taxes (ARAM EDIT).

Q. Are additional adjustments for other issues proposed by other Staff?

A. Yes. The Company's filing is complex, and a thorough review can involve multiple Staff members looking at different issues. Individual Staff are

[1] NW Natural/100, Palfreyman-Kravitz/Page 13.

reviewing additions to different categories of utility plant, test year operating expenses, revenues, and the effects of escalation on individual accounts.

Docket No: UG 490 Staff/200
Mondragon/5

SUMMARY OF REVENUE REQUIREMENT

Q. What factors did Northwest Natural identify in its initial filing as the drivers of the requested rate increase?

A. NW Natural states that it has generated revenue growth, but that growth has been insufficient to offset costs for O&M and investments in rate base.[2] The biggest factor to NW Natural's increase of $375.4 million in rate base is the significant effort to modernize customer meters throughout their system.[3]

Q. When was the Company's last general rate case in Oregon?

A. The Company's last rate case, UG 435, was filed in December of 2021 with approved rates going into effect on November 1, 2022.[4]

Q. According to the Company, how has the Company's Oregon jurisdictional rate base changed since its last filing?

A. The Company's Oregon jurisdictional rate base has increased from $1.7 billion in UG 435 to $2.1 billion in UG 490, an increase of $380.7 million.[5]

Q. According to the Company, how has the Company's Oregon jurisdictional total operating expenses levels changed since its last filing?

A. The Company filed to recover total operating expenses of $675.2 million in UG 435,[6] and it is requesting to recover $886.6 million in the current filing.[7]

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2 NW Natural/1700, Walker/16.
3 NW Natural/100, Palfreyman-Kravitz/14.
4 *In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision.* UG 435, Order No 22-388, Entered 10/24/22, page 2.
5 UG 490-Exh. 1700-WP1 Revenue Requirements Model.
6 UG 435-Exh. 1300-WP1 Revenue Requirements Model. The amounts include Gas Purchased.
7 UG 490-Exh. 1700-WP1 Revenue Requirements Model. The amounts include Gas Purchased.

Q. What is the Company's proposed cost of capital?

A. The Company's filing proposes a rate of return of 7.406 percent with a capital structure of 50 percent equity and 50 percent debt, a 4.712 percent cost of debt, and 10.1 percent return on equity.

Q. Did you review the Company's cost of capital proposal?

A. No. The Company's Cost of Capital (CoC) proposal is reviewed by Staff witness Matt Muldoon in Staff/100 and Rose Pileggi in Staff/1600.

Q. Please provide background on how the Commission reviews a utility's general rate case filing.

A. The rates charged by a utility are based on the utility's "revenue requirement." To determine a utility's revenue requirement, the Commission determines for a specified test year:

1. The utility's forecasted gross revenues;
2. The utility's operating expenses to provide utility service;
3. The rate base on which a return should be earned; and
4. The rate of return to be applied to the rate base.[8]

Once a utility's revenue requirement is established, the Commission determines the rates the utility must charge different classes of customers to collect that revenue requirement, considering the different costs each of the different classes of customers impose on the utility's system.

Q. Have the parties agreed to adjust any components of the $154.9 million proposed increase?

[8] *Pacific Power* and *Light*, UE 116, Order No. 01-787, pp.5-6 (September 7, 2001).

Docket No: UG 490

Staff/200
Mondragon/7

A. Yes, the parties have reached an agreement related to the Company's cost of Long-Term Debt.

Q. Please provide a table summarizing Staff's proposed adjustments.

A. Figure 1 provides a table summary of Staff's proposed adjustments. Table 1 shows Staff's testimony exhibit numbers, the names of the Staff sponsoring the testimony, and a description of the adjustments. The last two columns show adjustments to Test Year revenues, expenses or rate base, and the revenue requirement effect based on Staff's proposed ROE range. Full support and explanations of the proposed adjustments can be found in the respective Staff members' testimony.

Figure 1: Staff Adjustments to Test Year

NWN UG 490
STAFF ISSUES SUMMARY
Test Year Ending October 31, 2025
($000)

Total Incremental Revenue Requirement on the Company's Filed General Rate Case							**$154,913**	**$154,913**
							Revenue Requirement Effect	
Testimony	**Issue No.**	**Staff**	**Proposed Staff Adjustments**	**Revenue**	**Expense**	**Rate Base**	**@ ROE Floor 8.9%**	**@ ROE Celing 9.3%**
100	S-0	Muldoon	Return on Equity	-	0	0	(18,819)	(12,770)
200	S-1	Mondragon	CS & Infor Dealer Relations	-	(8)	0	(11)	(11)
200	S-2	Mondragon	Sales Exp Dealer Relations	-	(62)	0	(88)	(88)
200	S-3	Mondragon	CS & Infor CPI Adj	-	(0)	0	(0)	(0)
200	S-4	Mondragon	Sales Exp CPI Adj	-	(4)	0	(6)	(6)
200	S-5	Mondragon	ARAM EDIT	-	(100)	0	(140)	(140)
500	S-6	Abraham	Gas Storage Expense	-	(194)	0	(275)	(275)
600	S-7	Anderson	North Coast Feeder (Sec B)	-	11	(6,400)	(601)	(619)
700	S-8	Beitzel	[redacted]					
800	S-9	Chipanera	OPUC Fees	-	137	0	194	194
800	S-10	Chipanera	Cash Working Capital	-	3	(513)	(45)	(46)
900	S-11	Dlouhy	Meter Plant	-	59	(9,316)	(814)	(841)
1000	S-12	Dyck	Intangible Plant/Genesys Contingency Fund	-	23	(3,650)	(319)	(329)
1000	S-13	Dyck	Office Supplies & CPI Adj	-	(688)	0	(975)	(975)
1000	S-14	Dyck	Admin Exp CPI Adj	-	104	0	147	147
1000	S-15	Dyck	Shareholder Meeting & CPI Adj	-	(219)	0	(287)	(287)
1000	S-16	Dyck	Rents CPI Adj	-	(30)	0	(43)	(43)
1200	S-17	Lockwood	Uncollectibles	-	(2,063)	0	(2,926)	(2,926)
1300	S-18	Moore	Distribution O&M	-	(4,491)	0	(6,371)	(6,371)
1300	S-19	Moore	Cust Acct O&M	-	(1,539)	0	(2,184)	(2,184)
1300	S-20	Moore	Materials & Supplies	-	26	(4,027)	(352)	(363)
1500	S-21	Peterson	Pension & Medical	-	(209)	0	(542)	(542)
1700	S-22	Rossow	Office Supplies	-	(8)	0	(12)	(12)
1700	S-23	Rossow	Advertising	-	(119)	0	(169)	(169)
1700	S-24	Rossow	Memberships	-	(352)	0	(499)	(499)
1700	S-25	Rossow	Meals/ Entertain	-	(237)	0	(364)	(364)
2000	S-26	Yamada	Sal&Wages O&M	0	(4,693)	0	(6,657)	(6,657)
2000	S-27	Yamada	Sal&Wages Capital	0	20	(3,187)	(279)	(288)
Total Staff-Proposed Adjustments :			**[CONFIDENTIAL]**	[redacted]				
Staff-Calculated Revenue Requirements (Base Rates):				**[CONFIDENTIAL]**	[redacted]			

Docket No: UG 490

Staff/200
Mondragon/8

ISSUE 1. CUSTOMER SERVICE & INFORMATION; SALES EXPENSE O&M (NON-LABOR)

Q. Please describe the activities and expenses associated with Customer Service and Information; Sales Expenses that you reviewed?

A. I reviewed Customer Service and Information; Sales Expense (Customer Service) recorded in FERC Accounts 907–916, excluding 909 Informational and Instructional Advertising Expenses and 913 Advertising Expense, which is analyzed separately. These expenses are for Supervision, Demonstrating and Selling, and Miscellaneous Sales expenses incurred in customer service and informational activities, promotional, demonstrating, and selling activities, except by merchandising, the object of which is to promote or retain the use of utility services by present and prospective customers.[9]

Q. Does the Commission Staff have a standard for how these expenses are treated for ratemaking purposes?

A. Oregon Administrative Rule 860-026-0020—Standards Governing Promotional Activities and Concessions—mandates that all promotional activities be just, reasonable, prudent, economically feasible and beneficial to both the utility and its customers.

Staff reviews expenses per appropriate use per FERC account. Staff also reviews transaction-level data to ensure expenses relate to activities such as responding to customer requests, inquiries, and safety concerns, resolving

[9] PART 201—Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act. https://www.ecfr.gov/current/title-18/chapter-I/subchapter-F/part-201.

customer complaints, extending service to new customers, and providing information about safety and service issues.

Q. What is the Company proposing regarding Customer Service Information and Sales Expenses?

A. The Company is proposing to increase Oregon allocated expenses by $26 thousand or 5.6 percent to $470 thousand.

Figure 2: Base Year to Test Year

Account		Test Year 10/31/2025 Company Wide	Test Year 10/31/2025 Oregon Allocated	Base Year 12/31//23 Company Wide	Base Year 12/31//23 Oregon Allocated
907	CS and Information Supervision	-	-	-	-
908	Customer assistance Expense	45,169	39,922	43,437	38,392
910	Misc. Customer Service	5,024	4,407	4,753	4,169
911	Sales Supervision	6,493	5,706	6,118	5,377
912	Demonstrating and selling exp	477,137	420,171	449,737	396,043
916	Misc. Sales exp	-	-	-	-
TOTAL O&M Expense (Less Advertising)		533,822	470,207	504,046	443,981

Q. Please describe the Company's Customer Service Information and Sales Expenses in the Base Year and Test Year.

A. NW Natural's Base Year is January through December of 2023 using actual expenses through September 2023 and forecasting the remaining three months of 2023 to develop the total Base Year.[10] NWN adjusted Base Year

[10] NW Natural/1400, Davilla/2.

expense using the most current West Region Urban CPI of 5.6 percent to arrive at the Test Year amounts.

The Company reported a Base Year Oregon allocated non-labor total of $444 thousand for Customer Service expenses. Demonstrating and Selling expenses (FERC 912) make up 89 percent of the Customer Service Base Year. This includes the materials and expenses incurred in promotional, demonstrating and selling activities in the effort to promote and retain present customers and prospective customers. Of this amount, 76 percent of the expenditures in this account are professional services, materials, prices, meals, and sponsorships to support NWN's Corporate identity.

Q. How did Staff perform its analysis of Customer Expenses?

A. Staff reviewed Base Year expenses for appropriate use of FERC account, reviewed transaction-level data to ensure expenses relate to activities such as providing general direction of customer service activities, encouraging safe, efficient, and economical use of the utility's services, as well as costs associated with activities related to the promotion and retention of the use by present and prospective customers. Professional Services, Corporate Identity and Dealer Relations make up the majority of Base Year expenses.

Q. What is Staff's analysis of the programs included in Customer Expenses?

A. Most Professional Services were recorded in FERC Account 908 – Customer Assistance Expense. In this account, 90 percent of Professional services are related to the Weatherization program, while six percent are related to FERC

Account 912 – Demonstrating and Selling Expenses. It is worth noting that services related to the Low-Income Weatherization program are offset by the Company's Oregon Low Income Energy Efficiency (OLIEE) Program. The OLIEE Program is funded through the Public Purposes Funding Surcharge (Schedule 320) and is used to help customers who qualify as low-income, defined as less than 200 percent of the federal poverty line.[11] The Demonstrating and Selling costs were made up of help desks and booths as well as Safety and Innovation outreach and engagement events.[12]

Figure 3: Professional Services

Cost element name	PROFESSIONAL SERVICE		
Row Labels	**Base Year**	**Description of Base Year events**	**Test Year**
908	**2,500,175**		**2,658,619**
10069	984,323	Low Income Weatherization	1,049,332
10099	6,812	Energy Solutions Fee for industrial newsletter	7,262
10102	2,471	No description/justification provided	2,634
10161	-		-
10198	8,332	Tote bags/weatherization kit/printing	8,883
10206	1,419,738	Weatherization	1,507,526
10457	45,568	Gas Heat Pump Consultant and GHPWH committee Fees	48,578
10764	32,932	Co Star data/housing industry news/JD Power data and anlytics services/Johnson Econimics market report	34,406
912	**169,291**		**180,408**
10104	6,000	Professional - KPTV	6,396
10108	2,114	No description/justification provided	2,190
10163	49,774	booths and signage for Street of dreams	53,062
10178	111,402	Natuarl Gas Safety Consumer Engagement events	118,760
Grand Total	2,669,466		2,839,027

Corporate Identity is comprised of event sponsorships, networking events and booths at events. Corporate identity was tracked in FERC Account 912 – Demonstrating and Selling Expenses. Base Year expenses total 62 thousand.

[11] Staff Exhibit 202 and NW Natural/200, Tanaka/24-25.
[12] Staff Exhibit 202, NW Natural response to DR 334 and 438.

Docket No: UG 490

Staff/200
Mondragon/12

Figure 4: Corporate Identity

Cost element name	CORPORATE IDENTITY		
FERC_Cost Center	**Base Year**	**Description of Base Year events**	**Test Year**
908	**528**		**555**
10099	528	Pacific NW Steel Fab_Networking golf event	555
912	**61,670**		**64,567**
10177	14,814	Homes and Garden Shows	14,870
10178	-		-
10179	98	St. Jude Reception & Camp fire lunch	105
10180	15,308	Parade of Homes sponsorship, North Plains 60th Bday sponsorship	16,099
10181	25,296	Event booth/Salem Faimily Festival sponsorship/Homeless project/City Nit out Sponsorship	26,932
10185	6,154	Street of Dreams sponsorship fee	6,561
Grand Total	62,198		65,122

Dealer relations consist of registration fees for builder events, treats and refreshments for trade allies, VIP dinners and lunches, block parties, and Get Ready events. In response to a DR issued by Earthjustice regarding promotional concessions, NW Natural identified a total of $41 thousand in Test Year expense that it has inadvertently included in the Company filing and which would be removed in NWN's subsequent reply testimony.[13]

[13] Staff Exhibit 202, NW Natural response to Coalition DR 72.

Docket No: UG 490

Staff/200
Mondragon/13

Figure 5: Dealer Relations

Cost element name	DEALER RELATIONS		
FERC_Cost Center	**Base Year**	**Description of Base Year events**	**Test Year**
908	**11,618**		**12,381**
10102	3,454	Cookies & Candy for Trade allys & other that will removed in reply testimony& BIA lunch meeting sponsorship	3,682
10103	44	Water and Soft Drinks for Hosted ASHRAE Meeting @	47
10161	7,620	Registration fee for Professional Women's Builder event/Home builder event/Realtor trade event/Canopy at Trade event/ PMA realtor dues/outdoor oven	8,119
10457	500	ESC Gas Heat Pump Magazine	533
912	**131,258**		**139,013**
10104	54,641	Coop advertising -will be removed in reply testimony/food & equpment rental for HVAC dealer breakfast meeting/training ceertification for dealers	57,355
10163	25,907	Oregon Smart Growth refreshments & sponsorship of Oregon Hme builders Association conference	27,609
10165	2,000	Cookies & Candy for Trade allys	2,132
10178	-		-
10179	1,289	coded incorrectly-should have been materials	1,381
10180	4,152	Tour of homes/Parade of Homes VIP dinner & Lunch/St Jude VIP dinner	4,427
10181	39,792	Get Ready Events/Homeless Connect Project/Veterans Stand Down Event	42,404
10185	3,476	SOD Lunches/Block Party	3,706
Grand Total	142,875		151,394

Q. Did Staff perform any other analysis of the Customer Expenses?

A. Yes. Staff reviewed historical data for trends, variances, averages, and growth. Overall, the expenses in this category have declined since 2021. This result may be due to the Company incorporating the feedback received in the prior rate case and making changes to charge to non-recoverable cost centers. The only account to see an increase is Supervision (FERC 911), growing by 393 percent since 2021 and at 50 percent above the three-year average. Although these percentages seem large, the actual dollar amounts are small. Figure 6 below shows the comparisons.

Docket No: UG 490

Staff/200
Mondragon/14

Figure 6: Customer Expenses Analysis

Account		Test Year to Base Year $$	Test Year to Base Year %	Test Year to Average $$	Test Year to Average %	Test Year to Base Year Staff CPI Escalated $$	Test Year to Base Year Staff CPI Escalated %	Growth to Test Year $$	Growth to Test Year %
907	CS and Information Supervision	-	0.0%	-	0.0%	-	0.0%	-	0%
908	Customer assistance Expense	1,531	3.8%	(241,219)	-604.2%	393	1.0%	(406,806)	-91%
910	Misc. Customer Service	238	5.4%	(7,073)	-160.5%	65	1.5%	(3,278)	-43%
911	Sales Supervision	329	5.8%	2,860	50.1%	91	1.6%	4,548	393%
912	Demonstrating and selling exp	24,128	5.7%	(326,538)	-77.7%	6,687	1.6%	(430,828)	-51%
916	Misc. Sales exp	-	0.0%	-	0.0%	-	0.0%	-	0%
TOTAL O&M Expense (Less Advertising)		26,225	5.6%	(571,969)	-121.6%	7,236	1.5%	(836,364)	-64%

Q. Does Staff recommend an adjustment?

A. Staff proposes two adjustments:

- As ratepayers receive little benefit from event sponsorships, fees paid to Home Building Associations, home tours, building industry events and other related activities they do not satisfy the criteria for rate recovery under OAR 860-026-0020(1). Staff recommends adjusting the Test Year expenses by ($108,457) system-wide or ($95,858) Oregon allocated to remove Dealer Relation costs.

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Staff/200
Mondragon/15

Figure 7: Recommended Adjustment listing

FERC_Cost Center	Test Year	Description of Base Year events
908	**11,848**	
10102	3,682	Cookies & Candy for Trade allies & other that will removed in reply testimony& BIA lunch meeting sponsorship
10103	47	Water and Soft Drinks for Hosted ASHRAE Meeting @
10161	8,119	Registration fee for Professional Women's Builder event/Home builder event/Realtor trade event/Canopy at Trade event/ PMA realtor dues/outdoor oven
912	**96,609**	
10104	57,355	Coop advertising -will be removed in reply testimony/food & equpment rental for HVAC dealer breakfast meeting/training ceertification for dealers
10163	27,609	Oregon Smart Growth refreshments & sponsorship of Oregon Hme builders Association conference
10165	2,132	Cookies & Candy for Trade allies
10179	1,381	coded incorrectly-should have been materials
10180	4,427	Tour of homes/Parade of Homes VIP dinner & Lunch/St Jude VIP dinner
10185	3,706	SOD Lunches/Block Party/
	108,457	

- Adjust the Oregon allocated Test Year Customer Service & Information; Sales Expense O&M (NL) by ($5,810) to account for Staff-proposed updated CPI escalations. Staff Exhibit 800 Chipanera further explains Staff's CPI escalation.

Docket No: UG 490 Staff/200
Mondragon/16

ISSUE 2. EXCESS DEFERRED INCOME TAX

Q. Briefly describe excess deferred income taxes and the Commission's resolution in NW Natural's recent rate cases.

A. For purposes of this rate case, Excess Deferred Income Taxes (EDIT) are deferred taxes paid by customers in rates prior to 2018 that became refundable as a result of the 2017 Tax Reform Act that reduced the Federal corporate tax rate from 35 percent to 21 percent. EDIT can be either protected or unprotected. Protected EDIT can be returned to rate payers no faster than the rate allowed under IRS normalization rules (also known as the Average Rate Adjustment Method or ARAM). The 2017 Tax Act created three categories of EDIT for NW Natural:

- Protected EDIT
- Unprotected EDIT
- Gas Reserves EDIT

The ratemaking treatment of each type of EDIT has been addressed in prior Commission orders.[14] In this case, Staff has no issues with NWN's ratemaking treatment of Unprotected and Gas Reserved EDIT but does propose an adjustment to Protected EDIT.

[14] *In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision*, UG 344, Order No. 19-105 (March 25, 2019); *In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision*, UG 388, Order No. 20-364 (October 16, 2020); *In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision*, UG 435, Order No. 22-388 (October 24, 2022).

Docket No: UG 490

Staff/200
Mondragon/17

Q. Please summarize how the protected ARAM EDIT is reflected in this case.

A. ARAM EDIT amortization in the amount of $3.1 million is included in rate base.

NW Natural
UG 490 - Oregon Jurisdictional Rate Case
Rate Base & Depreciation Expense - Oregon and System
Test Year Twelve Months Ended October 31, 2025
Base Year Twelve Months Ended December 31, 2023 (Actual and Estimate)
($000)

Line No.	Rate Base	Test Year Oregon (a)	Test Year System (b)	Base Year Oregon (c)	Base Year System (d)
1	Utility Plant in Service	4,120,671	4,665,889	3,608,816	4,077,902
2	Accumulated Depreciation	(1,638,721)	(1,834,526)	(1,464,792)	(1,638,760)
3	Net Utility Plant	2,481,950	2,831,363	2,144,025	2,439,142
4	Aid in Advance of Construction	(6,499)	(10,902)	(6,517)	(10,739)
5	Customer Deposits	(755)	(859)	(677)	(770)
6	Gas Inventory (Working and Cushion)	43,889	49,307	63,623	71,479
7	Leasehold Improvemets	18,596	21,046	21,314	24,121
8	Materials & Supplies	21,810	25,496	19,452	22,740
9	Accumulated Deferred Income Taxes - Depreciation	(441,529)	(484,777)	(429,494)	(471,607)
10	Accumulated Deferred Income Taxes - Other	(6,360)	(7,071)	(8,562)	(9,426)
11	EDIT Rate Base Adjustment	3,100	3,563	3,100	3,563
12	Cash Working Capital	22,159	24,738	19,852	22,163
13	Total Rate Base	2,136,361	2,451,905	1,826,116	2,090,666

In NW Natural's last GRC, UG 435, Staff proposed to increase ARAM EDIT amortization by $100 thousand from $3 million.[15]

Q. What is the ARAM "speed limit"?

A. The "speed limit" is a term coined by NW Natural in its 2020 rate case, UG 388, that simply means the maximum rate that ARAM EDIT benefits can be returned to ratepayers without triggering a normalization violation.[16]

Q. What is a normalization violation?

A. Normalization is a system of accounting used by regulated public utilities to reconcile the tax treatment of the Investment Tax Credit (ITC) or accelerated

[15] UG 435 Staff/300, Fox/17.
[16] See In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision, Docket No. UG 388, NW Natural/2500, Borgerson/22.

depreciation of public utility assets with their regulatory treatment. Under normalization, a utility receives the tax benefit of the ITC or accelerated depreciation in the early years of an asset's regulatory useful life and passes that benefit on to ratepayers ratably over the regulatory useful life in the form of reduced rates.[17]

A violation of the normalization rules would, in particular, eliminate NW Natural's ability to use accelerated depreciation for tax purposes which would have significant negative impacts on the Company's cash flow.

Q. Please elaborate on the Company's response to Staff's data request regarding ARAM EDIT.

A. The Company provided its ARAM EDIT estimates through 2028. The Company estimates that under the current depreciation rates, 50 percent of plant EDIT will be amortized by 2038. Additionally, NWN estimates its actual ARAM amortization will average $2.99 million per year between 2024 and 2026.[18] The slightly higher benefit of $3.1 million in rates reduces the cumulative outstanding balance due to ratepayers that the Company estimates will be $817 thousand at the end of 2028. Increasing the benefit in rates to $3.2 million would bring the balance closer to zero.

Q. Will increasing the amortization by $100,000 cause NWN to violate the normalization speed limit?

---

17 IRS Revenue Procedure 2017-47.
18 Staff Exhibit 202, NW Natural's response to DR 215.

A. No. The Company provided their ARAM EDIT amortization workpapers where annual amortization and the ARAM Speed limit are calculated.[19] The Speed limit is the cumulative allowable ARAM amortization. Adjusting the amortization amount to $3.2 million annually, increases the actual amortization but stays under the cumulative allowable amount by $316 thousand in 2024 and $317, thousand in 2028, therefore not exceeding the Speed limit.

	Amortization Amount (calendar years)					
	2023	2024	2025	2026	2027	2028
ARAM	2,724,620	2,817,269	2,986,064	3,153,668	3,282,502	3,378,901
Amortization in Rates (Pre Gross-up)	3,100,000	3,200,000	3,200,000	3,200,000	3,200,000	3,200,000
Cumulative Allowable Amortization	13,951,714	16,768,983	19,755,047	22,908,714	26,191,217	29,570,117
Cumulative Actual Amortization	13,252,445	16,452,445	19,652,445	22,852,445	26,052,445	29,252,445
(Over)/Under ARAM Speed Limit	699,269	316,538	102,602	56,270	138,772	317,673

Q. What does Staff recommend?

A. Staff recommends increasing the ARAM EDIT amortization in rates from $3.1 million to $3.2 million, thereby decreasing the amount of federal tax expense by $100 thousand per year. This represents a compromise that will return benefits to customers faster while still leaving a reasonable buffer in the cumulative amount returned.

[19] Staff Exhibit 202, NW Natural response to DR 215.

Docket No: UG 490

Staff/200
Mondragon/20

ISSUE 3. INTEREST SYNCHRONIZATION

Q. Please explain what Interest Synchronization is.

A. Interest Synchronization computes the interest component of the revenue requirement. It is computed by multiplying the rate base by weighted cost of debt and comparing it against the interest expense used by the Company in the Test Year. The tax effect of the difference is adjusted and ensures that the revenue requirement reflects the change in interest.[20]

Q. What is the Commission's policy and historical treatment of Interest synchronization?

A. According to long-standing Commission policy, for ratemaking purposes, Staff routinely synchronizes interest expense to reflect changes to the regulated utility's cost of capital as initially filed in a general rate case. Interest expense must be coordinated or synchronized to determine the related adjustment for the income tax calculation.

Q. What is the Company proposing in rate base and weighted cost of debt in this rate case?

A. NW Natural is proposing $2.136 million in rate base and requesting a weighted cost of long term (LT) debt of 2.36 percent.

Q. Does Staff object to the Company's proposal?

[20] NARUC Revenue Requirement Model. https://pubs.naruc.org/pub.cfm?id=5389DCB3-2354-D714-5191-39A4E8DF9C2C.

A. No. during settlement discussions on February 12, 2024, Parties agreed on a cost of LT debt of 4.712 percent which resulted in a Weighted Cost of LT Debt of 2.36 percent.[21]

Regarding Rate Base, members of Staff will independently testify and propose adjustments to Rate Base, if any.

Q. Does Staff have any recommendations on this issue?

A. No. Staff has no recommendations given the result of the settlement of LT debt mentioned above.

[21] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, UG 490, First Partial Multi-Party Stipulation (February 26, 2024).

Docket No: UG 490 Staff/200
Mondragon/22

ISSUE 4. BUDGET TO ACTUALS

Q. Please describe NW Natural's budgeting process?

A. The O&M budget is performed annually, typically beginning in October, and is finalized usually by year end. The budget is performed at the cost center and GL account level, however, not every cost center or GL receives a budget. The O&M FERC accounts are not considered in the budget process. Rather than being in 80 different cost centers, Budgets are accounted for, most often, in a single node and the variances are compared only at the node level.

Q. How does the Company monitor variances between budgeted and actual revenues and expenditures?

A. On a monthly basis, the Finance Committee reviews financial results and explanations or variances. On a quarterly basis, Internal Audit is invited to attend the monthly meetings.

The Income Statement and Balance Sheet are presented and explanation of cost drivers and changes from the prior month are discussed. O&M is reviewed at the Cost Center level with explanations required for areas greater than $25 thousand in variance.[22]

NW Natural states that

[T]he Company's goal is to manage operating expenditures to the *annual budgets. On a monthly basis, the business units are asked to provide variances for the month, YTD and for the remainder of the year. When variances are identified, the business units are asked to*

[22] Staff/Exhibit 202, NW Natural's response to DR 203.

identify if the variance is timing related or permanent. These variances for the business units are then rolled up, and if there are significant permanent overages on an aggregated basis, the Finance team engages the Company on an effort aimed at reducing the overage by reprioritizing expenses.[23]

Q. How did Staff perform its analysis of the Budget to Actuals?

A. Staff requested the budgeted and actuals amounts for each of the approximately 950 cost centers for the calendar years of 2021, 2022, and 2023. Staff then used NW listing of internal accounts and cost centers[24] to create connections between Cost Centers and categorized Cost Centers as either Operations or Administrative & General accounts. Staff analyzed and requested explanations from the Company for

- Variances in budgeted amounts versus actuals.
- Change in actuals over the years.
- Change in budgeting over the years.

Q. What were Staff's findings?

A. Staff's analysis found that overall the Company stayed under their annual budget in both 2022 and 2023 in Operations and A&G.

[23] Staff/Exhibit 202, NWN response to DR 204.
[24] Staff/Exhibit 202, NWN response to DR 78.

Docket No: UG 490

Staff/200
Mondragon/24

Figure 8: Budget to Actual Variances

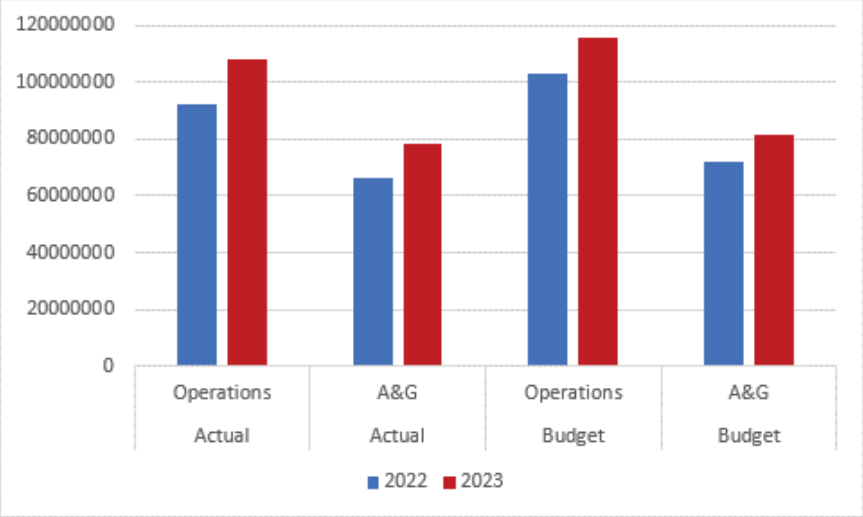
	2023		2022	
Operations	(7,494,832)	-6%	(10,781,599)	-10%
A&G	(3,101,664)	-4%	(5,904,083)	-8%

Although the Company has maintained cost control over expenditures, Staff found that the Company's budget as well as actuals have increased from 2022 to 2023. Staff has issued DRs for more information (due back April 5).

Docket No: UG 490

Staff/200
Mondragon/25

Figure 9: Change over the Years



Q. Does Staff have any concerns with the Company's ability to control costs?

A. Staff does not have concerns regarding the Company's ability to control costs.

Q. Does Staff recommend any adjustments?

A. No.

Docket No: UG 490

Staff/200
Mondragon/26

SUMMARY

Q. Please summarize your recommendations, identifying any adjustments you propose.

A. Staff proposes to the following adjustments

- Customer Service
  - Reduce Test Year A&G expense by ($95,858) Oregon allocated, related to Dealer Relation costs.
  - Adjust the Oregon allocated Test Year by a reduction of $5,810 to $368,859 to account for updated CPI escalations.
- Excess Deferred Income Tax
  - Increase the ARAM EDIT amortization in rates from $3.1 million to $3.2 million.

My recommendations may change based on further review and as informed by the testimonies offered by other parties.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 490
WITNESS: LUZ MONDRAGON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualifications Statement

April 18, 2024

Docket No. UG 490

Staff/201
Mondragon/1

WITNESS QUALIFICATIONS STATEMENT

NAME: Luz Mondragon

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Financial Analyst
Rates, Safety and Utility Performance Program (RSUP)

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION: Western Governors University
Bachelors of Science in Accounting

EXPERIENCE: I have been employed with the PUC since March of 2023 as a Senior Finance Analyst tasked primarily with research and analysis of utility company filings, including, affiliated interests and rate case dockets.
I have over 15 years of accounting/finance experience, most recently working for Northern Wasco County PUD as a Finance Analyst. My duties included financial reporting, internal and external, as well as budgeting. I also worked very closely with the Engineering team on work orders, inventory, capital budgets and Plant assets.

CASE: UG 490
WITNESS: LUZ MONDRAGON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 202

Exhibits in Support
Of Opening Testimony

April 18, 2024

Docket No. UG 490

Staff 202
Mondragon/1

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 Coalition DR 72

Please describe all promotional concessions NW Natural intends to offer during the Test Year.

Response:

NW Natural objects under OAR 860-001-0500 to the request that the Company describe all promotional concessions offered during the Base Year, in that the information requested is not relevant to this proceeding or not reasonably calculated to lead to admissible evidence and is not commensurate with the needs of this case, the resources available to the parties or the importance of the issues to which the discovery relates. The Company did not intend to seek cost recovery in this rate case for any promotional concessions.[1]

To that end, and without waiving the Company's objections, there are four expenses included in the filing that the Company inadvertently included in its cost recovery request.

Base Year total for these expenses is $31,992.99. Test Year total is $41,014.70. The Company will update its revenue requirement in its reply testimony.

The four Test Year expenses are explained here:

Date	Paid to	Purpose	Base year / Test Year expense
9/26/2023	NW Natural Appliance Center	Purchase of gas outdoor oven for installation at a home showcase. Demonstration of outdoor gas cooking equipment.	**Base Year:** $1,994.99 **Test Year** $2,185.63

[1] OAR 860-026-0015(1) states, in relevant part, that "promotional concession" means "any consideration offered or granted by an energy … utility or its affiliate to any person with the object, express or implied, of inducing such person to select or use the service or additional service of such utility, or to select or install any appliance or equipment designed to use such utility service." OAR 860-026-0015(2) provides examples of promotional concessions for illustrative purposes, and OAR 860-026-0015(3) lists activities that are not promotional concessions.

Docket No. UG 490

Staff 202
Mondragon/2

UG 490 Coalition DR 72
NWN Response

5/15/2023	Western Outdoor Wholesale Inc	Purchase of three high-efficiency gas tankless water heaters for installation at a home showcase. The tankless systems included battery backup devices that demonstrated to the public show visitors (with signage) how tankless units could be enabled for operation during a power outage.	**Base Year:** $19,998 **Test Year** $21,908.97
9/7/2023	Willamette Woodstove Inc DBA Home Fire Stove	Advertising coop paid to a hearth dealer. This was previously disclosed in UG 490 OPUC DR 334.	**Base Year:** $5,000 **Test Year** $8,460.05
12/22/2023	Lisac's Fireplace & Stove Inc	Advertising coop paid to a hearth dealer.	**Base Year:** $5,000 **Test Year** $8,460.05

Docket No. UG 490

Staff 202
Mondragon/3

NW Natural®

Rates & Regulatory Affairs
UG 490
2024 Oregon General Rate Revision
Data Request Response

Request No.: UG 490 SDR 78

Please provide a table in the format below (See Table 1) of all internal accounts used by the utility. Organize the list so that the FERC account numbers are listed in numerical order and each internal account assigned to that FERC account is also in numerical order. For each internal account number include the description provided to employees to assist them in allocating the item to the appropriate internal account(s). Please also provide a cross-reference document that lists all internal account numbers in numerical order and indicates to which FERC number they are assigned (See Table 2).

Table 1

FERC Account	Internal Account Number	Description of Internal
908	XXXX1	
908	XXXX2	

Table 2

Internal Account	FERC Account
XXXX01	90X
XXXX02	59X

Response:

Please see Excel file UG 490 SDR 78 Attachment 1. The Excel file lists all cost centers by FERC account used in NW Natural's SAP accounting system.

The Company updated its account coding processes in 2022 eliminating the statistical internal orders. Therefore, the results for SDR 78 and SDR 79 are both for cost centers only.

The spreadsheet contains the following two tabs:

Table 1 – By FERC Account

Table 2 – By Cost Center

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 203

When executing an approved budget, please describe how NW Natural monitors and analyzes variances between budgeted and actual revenues and expenditures.

Response:

Financial results are reviewed monthly and explanations for variances are performed. Results are presented at a monthly Finance Committee which includes members from Accounting, Finance, Tax, Cash Mgmt., and Treasury. On a quarterly basis, also Internal Audit is invited to attend the review meeting.

The Income Statement is presented, and explanations and drivers of the variances are explained. Margin (revenues less cost of gas) and O&M are explained in further detail after the income statement review.

Margin is reviewed in greater detail and this includes not only financial variances but reviews customer counts, volumes and weather variances.

O&M is reviewed in greater detail as well each month and the review is performed at the cost center level with variance explanations required for those areas greater than $25K in variance.

Balance Sheet items are reviewed in the Finance Committee meeting. Changes are reviewed and discussed comparing current month results to the same month in the prior year.

Lastly in the Finance Committee, the Treasury and Cash Management teams walk through the Cash Forecast and explain the drivers of the difference between the cash or borrowing position compared to the budget.

Outside of the Finance Committee, Capital is also reviewed and explanations are gathered from the business unit to explain variances for the month and year to date at the applicant level.

Docket No. UG 490

Staff 202
Mondragon/5

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 204

Referencing the data request immediately above, does NW Natural have defined budget variance tolerance levels for specific revenue or expenditure categories?

a. If yes, please include a brief description of how each variance tolerance threshold is developed.
b. If actual expenditures exceed budget variance tolerances without a commensurate increase in revenues, please describe the process for re-aligning expenditures to budgeted levels.

Response:

a. Yes, there are some variance tolerance thresholds that are defined. These are defined by management along with the SOX Compliance Office to determine the appropriate precision to ensure complete and accurate financial statements. NW Natural has defined SOX controls that require investigation into O&M cost center variances of $25k or more and remaining income statement variances of $50k or more.

b. The Company's goal is to manage operating expenditures to the annual budgets. On a monthly basis, the business units are asked to provide variances for the month, YTD and for the remainder of the year. When variances are identified, the business units are asked to identify if the variance is timing related or permanent.

   These variances for the business units are then rolled up, and if there are significant permanent overages on an aggregated basis, the Finance team engages the Company on an effort aimed at reducing the overage by reprioritizing expenses.

Docket No. UG 490

Staff 202
Mondragon/6

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 215

Regarding Exhibit 1710 Taxes

a. Please explain why corporate activity tax (CAT) expense is not being treated as deductible expense in the ratemaking state tax calculation.
b. At the current Average rate assumption method (ARAM) amortization rate, how many more years will it take NWN to amortize the $143 million in Plant EDIT that resulted from 2017 Tax Reform Act?
c. Please provide the actual and anticipated ARAM EDIT amortization, by year, from the date of inception through 2028. Provide data in a spreadsheet, including ongoing balances, keeping formulas intact and providing all workpapers with associated calculations.

Response:

a. It is our current position, and was our intention in preparing the revenue requirement, that the Oregon Corporate Activity Tax (CAT) be included as a deductible expense for purposes of calculating state income tax. We have reported the CAT in a similar manner when preparing our Oregon corporate income tax returns. Any deviation from this position is/was inadvertent and will be corrected.

b. As a result of the 2017 Tax Cut and Jobs Act (TCJA), NW Natural and interested parties determined that the Company's excess deferred income tax (EDIT) for plant was $143 million and that $128.4 million of the plant related EDIT was allocable to Oregon. The plant related EDIT balance is being amortized in rates, as a reduction of income tax expense, subject to the limitations imposed under the average rate assumption method (ARAM). The speed of amortization under ARAM is heavily influenced by the depreciation rates used for ratemaking and financial reporting purposes. Any changes in approved rates will result in changes to the ARAM amortization.

   Under currently approved depreciation rates in Oregon, we estimate that 50 percent of the total plant EDIT will be amortized by 2038 and 90 percent will be amortized by 2063. Under the updated cost recovery depreciation study, that is

currently before the OPUC, we estimate that 50 percent of the total will be amortized by 2032 and 90 percent will be amortized by 2048.

c. Please see the attachment, "UG 490 OPUC DR 215 NWN Attachment 1.xlsx." Excel columns BP through BZ display the calculated average rate assumption method (ARAM) amortization for the calendar years 2018 through 2028. Excel row 50, of the respective columns, indicates that over the eleven year period approximately 23 percent of the total Oregon allocated excess deferred income tax (EDIT) for plant will have amortized. Recall that, of the total plant related EDIT remeasurement of $143 million, $128.4 million was allocable to Oregon and documented in OPUC Order No. 19-105 (see pdf page number 22 of the Order).

Docket No. UG 490

Staff 202
Mondragon/8

NW Natural

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 334

Using OAR 860-026-0020 as a reference, for each Base Year Cost Element pictured below in accounts 907-916, please provide:

a. Description and total costs of each project or activity contained within the Cost Element.
b. Justification for each project or activity contained within the Cost Element.
c. The net customer benefit for each project or activity contained within the Cost Element.
d. The description and cost of any promotional items distributed to attendees.
e. Using Attachment A, provide
    i. A description of the invoiced services or goods and underlying support and documentation for each line item.
    ii. The business justification for each item and why ratepayers should pay any portion of these costs.

Cost Elements	
Row Labels	**Sum of OR Allocation Amount**
PROFESSIONAL SERVICE	2,189,654
CORPORATE IDENTITY	157,284
DEALER RELATIONS	85,388
OTHER CONTRACT WORK	64,152

Response:

Please see UG 490 OPUC DR 334 Attachment 1.

Responses for items a, b, c, d above are provided in columns N, O, P, Q of UG 490 OPUC DR 334 Attachment 1.

For expenses in cost center 10178 in UG 490 OPUC DR 334 Attachment 1: There are expenses that occurred in the base year but that we are not seeking recovery for in the Test Year. There was no request for recovery of expenses to cost center 10178 in GL

account 607500 Corporate Identity, 604600 Dealer Relations and 602100 Other Contract Work. In UG 490 - Exh. 1400 - OM Model Workpaper_High Confidential *or* UG 490 - Exh. 1400 - OM Model Workpaper-Non-Confidential, Dept Non-Payroll Forecast tab, excel line AI532:AI533 & AI541, you will see that the base year expense was adjusted to remove these expenses, and that in BH532:BH533 & BH 541, no Test Year amount is being requested.

Regarding North American Gas Heat Pump Collaborative (NAGHPC) expenses (the next-to-last two rows of UG 490 OPUC DR 334 Attachment 1).

- North American Gas Heat Invoice #307 – Oregon Allocated amount $21,200.24
- North American Gas Heat Invoice #206 – Oregon Allocated amount $19,074.43

Answers to Questions a, b, c, d are shown in the attached spreadsheet. Here is additional supporting information for NAGHPC expense:

NW Natural has recognized the need to reduce demand side gas usage. Adoption of Thermal Heat Pumps (aka Gas Heat Pumps or GHPs) are one means of doing so.

In our efforts to save customers energy and money, NW Natural is a member of the North American Gas Heat Pump Collaborative (the “Collaborative”). Its members are made up of energy efficiency professionals from gas and combination electric/gas utilities as well as the Northwest Energy Efficiency Alliance. The mission of the Collaborative is to accelerate the adoption of space and water heat GHPs for residential and commercial building applications as a means of reducing carbon emissions.

In pursuit of that mission, the Collaborative employs Market Transformation (MT) practices which have been employed by energy efficiency entities and utilities for emerging energy efficiency equipment and devices ranging from LED lighting to electric heat pump water heaters. MT can be defined as *the strategic process of intervening in a market to create lasting change that results in the increased and/or accelerated adoption of energy efficient products, services, and practices*.

MT picks up where technology development ends: with the product. As such, MT practices support emerging products to smooth their entry and adoption by supply chains, installers, and ultimately end-customers. This involves understanding and addressing the hurdles new equipment can face such as the distribution supply chain, establishing installation best practices and understanding among installers, determining how/where the equipment will fit within energy codes, etc.

Rather than bear the expense and efforts on our own, NW Natural has participated in the Collaborative to a) leverage the expertise and knowledge of energy efficiency professionals across utilities, and to b) share in the initial work and costs across members. The Collaborative has engaged Resource Innovations, a well-regarded and known energy efficiency program administrator, to facilitate its work.

Docket No. UG 490

Staff 202
Mondragon/10

NW Natural

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 438

For each of the Base Year cost Elements pictured below

a. Provide a listing and description of each project of activity contained within the Cost Element.

b. Provide the total cost of each project or activity listed in part a. The sum of the projects or activities should match the Cost Element amount pictured below.

c. Provide the business justification for each project or activity listed in part a and why ratepayers should pay any portion of these costs.

d. Provide the net benefit to the ratepayer for each project or activity listed in part a.

e. Provide the description and cost of any promotional items distributed to attendees.

Row Labels	Sum of OR Allocation Amount
⊟908	3,091,531
DEALER RELATIONS	14,626
OTHER CONTRACT WORK	85,401
PROFESSIONAL SERVICE	2,991,504
Grand Total	3,091,531

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Staff 202
Mondragon/11

Cost Center	(Multiple Items)
Row Labels	**Sum of OR Allocation Amount**
912	**443,188**
CORPORATE IDENTITY	181,750
DEALER RELATIONS	80,181
OTHER CONTRACT WORK	31,906
PROFESSIONAL SERVICE	149,351
Grand Total	**443,188**

Response:

a. The detailed listing behind these cost element totals is provided in UG 490 OPUC DR 332 Attachment 1. The detailed listing includes the descriptions of the transaction details.

b. The totals in UG 490 OPUC DR 332 Attachment 1 match the cost element totals included in the request above for FERC 908 exactly. The totals in UG 490 OPUC DR 332 Attachment 1 are slightly higher for FERC 912 than the picture in the request, above; the source of the above-shown picture is unknown and, therefore, the Company is not able to reconcile the immaterial differences quantified below.

Row Labels	Sum of OR Allocation Amount	Sum of OR Allocation Amount	
912000	**From OPUC DR 332 Attachment 1**	**From DR 438 picture**	**Difference**
CORPORATE IDENTITY	194,830	181,750	13,080
DEALER RELATIONS	83,486	80,181	3,305
OTHER CONTRACT WORK	34,973	31,906	3,067
PROFESSIONAL SERVICE	153,153	149,351	3,802
Total	**466,441**	**443,188**	**23,253**

c. – e. The Company's response to UG 490 OPUC DR 334 and UG 490 OPUC DR 334 Attachment 1 address the January – September transactions of the above pictured totals. Refer to UG 490 OPUC DR 438 Attachment 1 for justification and net customer benefit for the remaining fourth quarter 2023 amounts as reconciled as follows:

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Staff 202
Mondragon/12

UG 490 OPUC DR 438
NWN Response
Page 3 of 3

		c-e addressed in UG 334	c-e addressed here in UG 438		
	Cost element name	Sum of OR Allocation Amount	Sum of OR Allocation Amount	Sum of OR Allocation Amount	Amount in DR 438 Picture
		Jan - Sept 2023	Oct - Dec 2023	TOTAL	
FERC 908	DEALER RELATIONS	9,942	4,684	14,626	14,626
FERC 908	OTHER CONTRACT WORK	23,643	61,758	85,401	85,401
FERC 908	PROFESSIONAL SERVICE	2,042,436	949,068	2,991,504	2,991,504
			1,015,510		
FERC 912	CORPORATE IDENTIY	158,218	36,612	194,830	181,750
FERC 912	DEALER RELATIONS	75,447	8,039	83,486	80,181
FERC 912	OTHER CONTRACT WORK	40,509	(5,536)	34,973	31,906
FERC 912	PROFESSIONAL SERVICE	147,217	5,936	153,153	149,351
			45,051		
		Total FERC 908 + 912 Jan-Sept	Totals DR 334	Difference	
	CORPORATE IDENTIY	158,218	157,284	934	
	DEALER RELATIONS	85,388	85,388	0	
	OTHER CONTRACT WORK	64,152	64,152	0	
	PROFESSIONAL SERVICE	2,189,654	2,189,654	(0)	

Note that in the fourth quarter of the base year these exact transactions are not used to forecast the Test Year as the Test Year is based off of the first 9 months of actuals and a forecast only.

CASE: UG 490
WITNESS: MICHELLE SCALA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Opening Testimony
Energy Justice

April 18, 2024

Docket No: UG 490

Staff/300
Scala/1

Q. Please state your name, occupation, and business address.

A. My name is Michelle Scala. I am the Energy Justice Program Manager employed in the Strategy and Integration Division (SID) of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/301.

Q. What is the purpose of your testimony?

A. The purpose of Staff's testimony is to provide and validate energy justice considerations as they intersect with the proposals and potential impacts of NW Natural's general rate case. I further elaborate on specific equity considerations in areas that have been identified as high-impact or high-priority energy justice issues; including, overall bill impacts, rate spread/rate design, and the residential bill discount update and associated cost recovery mechanism.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared the following supporting exhibits:

Exhibit Staff/301. Witness Qualifications Statement

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Energy Justice Overview 3
Summary. Findings and Recommendations..... 24

Docket No: UG 490

Staff/300
Scala/2

Q. Could there be changes or updates to Staff's position and recommendations?

A. Yes. My testimony represents issues identified to date. My recommendations and issues may change when informed by new data and after reviewing testimony and analysis by other parties.

Docket No: UG 490

Staff/300
Scala/3

ISSUE 1. ENERGY JUSTICE OVERVIEW

Q. Please briefly describe the primary role of energy justice in utility ratemaking.

A. The primary role of energy justice in utility ratemaking is to advance the equitable distribution of energy system costs and benefits across all customer segments. It aims to address disproportionate impacts of rate structures and energy policies on environmental justice communities.[1] An energy justice informed review applies the concepts of equity, affordability, accessibility, and participation against the utility's general rate case filing and existing operations.

Q. How has the Commission considered energy justice in ratemaking historically?

A. Specific and explicit considerations for energy justice in Oregon regulated utility general rate proceedings have emerged on a more systematic basis in the last four years. This is not to imply that tenets and principles of energy justice such as affordability and distributional equity have not been a part of Commission decision making in the past; only that achieving socially just outcomes in regulatory processes is an ongoing, growing effort that has

[1] Per Oregon Revised Statute (ORS) 756.010(5), "Environmental justice communities" includes communities of color, communities experiencing lower incomes, tribal communities, rural communities, coastal communities, communities with limited infrastructure and other communities traditionally underrepresented in public processes and adversely harmed by environmental and health hazards, including but not limited to seniors, youth and persons with disabilities.

recently become a more prominent piece built into Staff's analytical framework for assessing rate proposals and other utility filings.[2]

Q. Please describe to what extent NW Natural's proposal in UG 490 has considered energy justice.

A. In NW Natural's (NWN or Company) opening testimony, the Company dedicates several pages of testimony to communicate its efforts to incorporate energy justice and equity into its operations. In NW Natural/200, Company witness Cecelia Tanaka details the Company's equity actions and proposals relative to the following topics:

- Community Equity and Advisory Group (CEAG)
- Low-Income Needs Assessment (LINA)
- Income-Based Bill Assistance Programs
- Oregon Low-Income Energy Efficiency
- Mitigating Energy Burden in This Case
- NW Natural's Efforts to Address Diversity, Equity and Inclusion.

Additionally, in NW Natural/100, Company witnesses Justin Palfreyman and Zachary Kravitz introduce components of a "responsible growth strategy", including changes to the residential basic charge structure, that are intended to "address intra-class equity concerns between [the Company's] existing and new residential customers."

[2] Oregon Public Utility Commission Diversity, Equity, and Inclusion Strategic Plan (https://www.oregon.gov/puc/forms/Forms%20and%20Reports/2023-PUC-DEI-Plan.pdf).

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Staff/300
Scala/5

Q. Has Staff found the Company's existing actions and proposals sufficiently account for energy justice in this filing?

A. Not entirely. To clarify, Staff is very encouraged by the Company's dedicated space for equity testimony and actionable proposals to reflect affordability concerns and distributional equity in this filing. Staff also appreciates the Company's voluntary establishment and use of an equity advisory group in the CEAG. That said, there are some features of the Company's proposal where Staff is still investigating whether additional actions or adjustments are needed to optimize equity outcomes in this proceeding. Staff is particularly concerned with depth of the Company's analysis informing how environmental justice communities may be impacted by its proposals relative to:

- The Residential Bill Discount Program;
- Rate structure changes to the residential basic charge; and
- Overall impacts of the filed case on residential customers.

Staff also has some comments regarding the Company's use of the CEAG and whether there may be opportunities to explore increased visibility, impact, and accountability. Lastly, Staff wishes to elevate certain components of the Company's ongoing low-income energy efficiency program and provide considerations for how this activity may intersect with direct assistance programs such as the Residential Bill Discount, Schedule 33.

Q. Please briefly summarize Staff's energy justice concerns relative to the Company's proposed changes to Schedule 33, the Residential Bill Discount Program.

A. Staff witness Charles Lockwood discusses the Company's Schedule 33 proposal in length in Staff/1200. For the purposes of this testimony, Staff aims to amplify specific parts of Staff's review and position that are of particular import to equitable outcomes in the case. This includes concerns with the Company's methodology used to inform the Program revisions and the impact of the revisions and program growth, generally, on cost recovery through the Company's existing Schedule 335 rate structure.

Q. Please expand on Staff's concerns with the Company's methodology for informing Schedule 33 revisions.

A. Staff is not convinced that the model used by the Company to inform proposed changes in the Residential Bill Discount Program (BPD) adequately considers income distributions and levels of energy burden among participants.[3] In testimony, the Company proposes to revise its approach to setting discount tiers to reduce energy burden below three percent and explains its use of income mid-points in each of the discount tier income ranges as a means to estimate the level of assistance needed to do so.[4] In Staff/1200 Mr. Lockwood describes Staff's concerns that the use of a mid-point within any given income range to rationalize "better coverage

[3] Staff/1200.
[4] Energy burden in this context is a percentage based on the household's monthly energy bill divided by the household's income.

of reduced energy burden through the tier"[5] must assume a normal income distribution of participants within the tier. However, Staff has not seen evidence that this is in fact the case, nor that the methodology's assumed average residential customer usage value is representative of these groups either. As such, an arguably justified discount level, in reality, not only overlooks critical areas of need for households along the lower end of income ranges and/or higher end of usage patterns but may also limit the program's effectiveness for the majority of participants if the actual income distributions are skewed left and/or usage skewed right.

Q. Does Staff have any other concerns to share regarding this methodology?

A. Yes. Staff would note that the issues identified in the previous section are most pronounced for the highest burdened and lowest income households. To illustrate this point Staff uses the Company's estimates provided in NW Natural/200, Tanaka/24, which indicate that the mid-point methodology reduces estimated energy burden across tiers as depicted in Table 1.

Table 1. NWN Mid-point Methodology Estimated Energy Burden

Tier	Energy Burden		Level of Relief
	Before Discount	After Discount	
3	2.00%	1.70%	15%
2	2.80%	2.20%	20%
1	4.70%	2.80%	40%
0	14.00%	2.80%	80%

[5] NW Natural/200, Tanaka/23.

Looking at Tier 0, one can see much higher before discount energy burden that at or between any of the other tiers. Given that this is at the mid-point income, one can infer that energy burden exponentially increases as incomes approach zero. This is significant because it shows not only how extreme energy burden is for households qualifying in Tier 0, but also, that this particular design has rapidly declining benefits for those deeper in need (Table 2).

Table 2. Declining Tier 0 Impacts on Estimated Energy Burden

Tier 0			
% SMI	HH Income	Energy Burden	
		Before Discount	After Discount
0.15	$ 14,061.50	8.0%	1.6%
0.14	$ 13,124.07	8.6%	1.7%
0.13	$ 12,186.63	9.2%	1.8%
0.12	$ 11,249.20	10%	2.0%
0.11	$ 10,311.77	11%	2.2%
0.10	$ 9,374.33	12%	2.4%
0.09	$ 8,436.90	13%	2.7%
0.08	$ 7,499.47	15%	3.0%
0.07	$ 6,562.03	17%	3.4%
0.06	$ 5,624.60	20%	4.0%
0.05	$ 4,687.17	24%	4.8%
0.04	$ 3,749.73	30%	6.0%
0.03	$ 2,812.30	40%	8.0%
0.02	$ 1,874.87	60%	12.0%
0.01	$ 937.43	120%	24.0%

Q. Is Staff recommending that the Company offer deeper discounts for these customers?

A. Not at this time. Staff's discussion here is based on the intersection of two separate elements in the 2022 Key Baseline Evaluation Criteria shared in Docket No. UM 2211, the Energy Affordability Act Implementation Docket. Specifically, regarding the level of relief, Staff recommended utility interim rate programs 1) "prioritize [the] lowest income with the highest energy burden"; and 2) "explain how the interim rate was designed to provide a meaningful reduction of energy burden." [6]

Staff sees and appreciates NW Natural's methodology and proposal as endeavoring to meet the second criterion and looks forward to further exploration of rate designs in the ongoing dialogue on affordability and equity. However, in the interest of Staff's review and transparency in differential rate designs, Staff is compelled to point out the potential gaps in this model, particularly given its conflicts with the first criterion. Put simply, NW Natural's model, while generally benchmarked against a low energy burden target, obscures the level of need amongst the highest energy burdened households by using the mid-point income range absent consideration of actual participant income distributions in the program.

That said, Staff recognizes that this is a step forward from existing designs and would in fact bring more meaningful relief to all current and future participants in Tiers 1 and 0 simply by offering the higher discounts of 40 and 80 percent, respectively. Staff also acknowledges that it can be difficult to truly prioritize the lowest income with the highest energy burden,

[6] https://edocs.puc.state.or.us/efdocs/HAC/um2211hac17313.pdf

such that these households likely have zero income to weight against energy costs. To this end, Staff's recommendation here is not to discredit the proposal. Instead, Staff has asked the Company to frame this proposal as an incremental step to provide a more significant level of relief rather than a sound design based on the Company's mid-point methodology.[7]

Further, Staff supports the Company's intent to participate in the ongoing UM 2211 process. There, Staff, utilities, and stakeholders can continue to explore sustainable differential rate designs as well as how to leverage State and Federal partnerships in the efforts to reduce energy burden both via direct assistance and targeted demand side management.

Q. Does that mean Staff recommends the Commission adopt NWN's Residential Bill Discount proposal under this alternate framing?

A. Not yet. As explained in Staff/1200, the Company did not perform a cost analysis of the proposed changes on the program or Schedule 335 rates. Absent an understanding of how the Company expects the program to grow, both in terms of costs associated with the higher discount tiers and the participation rate, Staff is unable to assess the impacts of the proposal and cannot recommend approval at this time.

Q. If the Company is able to provide a cost analysis of the proposal on Schedule 335 rates, will Staff then support adoption?

A. No. Not only would Staff need to review the analysis prior to making its recommendation, but Staff also has preexisting concerns regarding the

[7] Staff/1200.

Schedule 335 rate structure that it recommends be addressed in this proceeding.

Q. Please explain.

A. Currently, the Company's cost recovery for the Residential Bill Discount Program is set up as a fixed dollar charge for all general service schedules. This structure effectively caps recovery from each customer type at the level of the fixed dollar charge. Table 3 displays NW Natural's current Schedule 335 rate structure.

Table 3. NW Natural Schedule 335, Bill Discount Program Recovery

Rate Schedule	Charge per Bill
2	$ 0.94
3	$ 3.24
27	$ 0.61
31	$ 25.90
32	$ 62.77

In PGE's 2023 General Rate Case, Docket No. UE 416, Staff argues, in length, about the importance of equitable cost recovery from these programs. While it is true that only income-qualified residential customers can participate and receive the direct benefits of these programs, Staff and other parties have also explained that the legal impetus for these programs omitted any cap on per site or per customer cost recovery and included nonbypassibility language. In this vein, Staff has argued that a more equitable cost recovery structure considers percentage of bill impacts when assessing the reasonableness of the per customer rate. Staff would also

note that implementing a more equitable rate structure does not necessarily preclude the existence of a cap if there is a sound argument to include one.

All that said, Staff does want to clarify that the actual average effect of the current structure shows minimal differences between residential and commercial customer percentage of bill impacts for Schedule 335. At this time, only industrial customers appear to have a lower Schedule 335 impact on average. Thus, the cost recovery restructure is not quite as pressing as Staff has observed in other programs. However, given the proposed changes to the discount structure and assumably, forecasted costs, Staff does believe it is necessary to evaluate Schedule 335 in this proceeding. Further, Staff also notes, generally, that it wishes to move towards a more consistent approach with interim bill discount program cost recovery and finds that the Schedule 335 fixed cost recovery model may be a potential deviation from recent recommendations.

Q. Are there any other concerns Staff would like to share relative to the Residential Bill Discount Program proposal at this time?

A. Yes. Staff would like to take this opportunity to reference its summary findings in its accompanying review of the Company's low-income energy efficiency operations and the 2022 Low-Income Needs Assessment (LINA) or Energy Burden Assessment (EBA). In short, Staff has found there to be significant opportunity for the Company to enhance energy efficiency programs among its environmental justice communities. Table 4 is a reproduction of the Company's Oregon Low Income Energy Efficiency

Docket No: UG 490

Staff/300
Scala/13

Program Annual Report to the Public Utility Commission of Oregon Program Year: October 2022 - September 2023, CAP Project Completions 2022-2023.

Table 4. CAP Project Completions 2022-2023

CAP Agency	Counties Served	Completions	Projections
Clackamas County CA	Clackamas	1	0
Community Action Organization	Washington	70	70
Community Action Team, Inc.	Columbia and Clatsop	0	8
Community Services Consortium	Benton, Linn and Lincoln	20	40
Homes for Good	Lane	2	20
Mid-Columbia Community Action Council	Hood River and Wasco	0	0
Mid-Willamette Valley CA	Polk and Marion	11	45
Multnomah County Weatherization & Energy Services	Multnomah	66	85
Yamhill Co CA Partnership	Yamhill	5	8
Oregon Coast Comm Action	Coos	0	0
All Agencies		**175**	**276**

As can be seen, there are notable gaps between the Company's OLIEE projections and completions. The Company's 2022 EBA, spoke in length about reducing barriers to energy-efficiency programs and increasing participation rates in the Company's offerings. It noted, this is particularly salient for highly energy burdened households that tend to require more targeted designs and outreach/marketing strategies. To this end, Staff

notes that the Energy Affordability Act is a multiprong policy push to tackle energy burden and while the Residential Bill Discount Program represents a significant component of that strategy, it is best delivered with commensurately targeted energy efficiency.

Q. Is the Company doing anything about these issues at this time?

A. Yes. At the March 20, 2024 public meeting, the Commission adopted Staff's recommendation to approve, with modifications, NW Natural's proposals to adjust Schedule 320, Oregon Low-Income Energy Efficiency Programs.[8] This proposal was submitted following engagement with Staff, stakeholders, and CAP agencies in an effort to revise Schedule 320 such that more funds could be allocated to qualifying customers for energy efficiency measure, including expanding eligibility to qualify households earning up to 80 percent SMI and removing project caps for qualified measure to be eligible for up to 100 percent reimbursement of the installed cost.

Staff's modifications included limiting the amount of funding that could be spent on the newly eligible cohort of 61-80 percent SMI in order to "maintain that the majority of low-income weatherization funds be spent on those with the lowest incomes."[9] Staff would also note that in Docket No. ADV 1562, the Commission approved a pause on OLIEE program collections, via Schedule 301, the Public Purpose Funding Surcharge in

[8] Docket No. ADV 1593, Advice No. 24-02 (https://edocs.puc.state.or.us/efdocs/HAU/adv1593hau327269054.pdf).
[9] Id.

acknowledgement of the buildup of the balance in the OLIEE account[10]. According to the Company,

> "The build-up is the result of a deliberate increase in funding, which began in early 2020, intended to increase energy efficiency measures for low-income customer dwellings and to enable the OLIEE program to have broader reach to low-income residents that have not previously benefitted from the OLIEE program. This increased funding was developed with the OLIEE Advisory Committee and approved by the Commission in Advice No. 19-19, docketed as ADV 1056. Subsequently the COVID-19 pandemic severely impacted the delivery of OLIEE program benefits that rely on in person and in-home projects and measures. While OLIEE project spending has since bounced back from pre-pandemic levels, the collection of OLIEE funds at the increased rate has resulted in a build-up of the OLIEE account."[11]

Altogether, Staff finds the Company is actively pursuing ways to improve its low-income energy efficiency programs but encourages robust monitoring of the changes for unintended consequences and continued dialogue on how to effectively bundle OLIEE programs with the Residential Bill Discount Program in this and/or the UM 2211 process.

Q. Staff also mentioned the CEAG as a potential intersection with these topics; what is the relevancy here?

A. Staff appreciates the Company's sincere commitment to equity informed decision making through the CEAG. In Staff's review, the Company provided charter documents and general descriptions of how the CEAG provides input to the Company and used the Bill Discount Program design and outreach as an

[10] Docket No. ADV 1562, Advice No. 23-25 (https://edocs.puc.state.or.us/efdocs/HAU/adv1562hau325663054.pdf).
[11] Id.

exemplar. Staff's only flags regarding the CEAG at this time is uncertainty regarding:

1. The visibility of these conversations,
2. The level of accountability the Company provides to the CEAG based on their input, and
3. The Company's commitment to expanding the CEAG's influence to system planning and investment.

Q. Please explain.

A. Staff is not making any recommendations at this time but does wish to continue discussions with the Company in the appropriate venue about how to address or resolve the aforementioned concerns. For example, while Staff appreciates these conversations are happening and the input is being collected, there is still some uncertainty with how this is being recorded and to what extent it can be shared ahead of the Company's assertions that proposals were informed or endorsed by the CEAG.

Staff is also sensitive to how community engagement can easily sour if the format is extractive or lacks agreed upon feedback loops and accountability measures. This is not to say those have not been addressed in NWN's model, and Staff recognizes a meaningful compensation structure is in place. However, Staff still feels some additional visibility and potential sharing of space for a bit of diversity in the content brought before the CEAG may be worth exploring.

This is particularly relevant in the face of some big questions and uncertainty around the Company's future business model and evolving role in the Oregon energy system and decarbonization goals. Put plainly, the topic of stranded costs associated with customers leaving the gas system and concepts of a "just transition" amid calls for electrification have come up in multiple dockets over the last several years.

The CEAG has made valuable progress on issues of accessibility and procedural equity, the Company should work to expand its scope to inform major issues facing the users of NW Natural's system. Staff believes it is important to socialize the tradeoffs of different pathways for the future of NW Natural's system and make the priorities and other feedback available for use in planning and ratemaking dockets... Staff is interested in hearing how the Company plans to use CEAG input to tackle more practical issues that inform its Company's long-term business strategy.

Q. Does this cover Staff's energy justice review of the Residential Bill Discount Program, low-income energy efficiency programs, and CEAG?

A. Yes. However, as noted earlier, perspectives and positions may expand following additional review, process, and dialogue in this proceeding.

Q. Staff had also flagged the residential rate structure change to the basic charge as relevant to energy justice concerns, what can be said about that?

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Staff/300
Scala/18

A. Staff wishes to use this testimony to highlight a particular concern regarding what Staff has found to be a significant and premature adjustment to the residential rate structure via the Company's basic charge proposal.

Q. Please explain.

A. The Company has proposed a revision to the basic charge that includes the following three changes:

- Increase the basic charge for residential single-family customer from $8 to $10.
- Implement a bifurcated basic charge that keeps the multi-family basic charge at $8.
- Create a new monthly charge of $16.25 for all new customers to the Company's system that would be added onto the Company's basic charge proposal.

This proposal was reviewed and discussed in length in Staff/1800. There, Staff notes that for the time being, it is supportive of the first two of the three changes. However, Staff opposes the new premise premium of $16.25 for several reasons also discussed in Staff/1800, the last of which how this proposal overlooks significant equity concerns that should be explored in further analysis. Specifically, the Company did not provide any visibility into the distribution of environmental justice communities comprising new premise customers versus existing customers.

While absent a more thorough exploration, one might assume that new premise customers are largely new homeowners, Staff's understanding is

that this cohort could just as easily include renters moving into newly constructed multi-family dwellings, some of which might be affordable housing units. To this end, it is very possible that this structural change exacerbates the disproportionate burdens faced by environmental justice communities. Specifically, Staff is referring to the interplay of environmental justice community households already having a reduced capacity to pay for a notably higher charge (i.e., more than three times the existing customer basic charge), with the possibility that these groups are overrepresented among new premise customers, leading to a cost shift at the expense of these groups.

Q. What was Staff referring to regarding the change being premature?

A. Staff notes that the Company referenced this change as one of the components to its "responsible growth strategy." Staff sees this effort to be ill-suited for a rate case proceeding that lacks the more diverse engagement framework and comprehensive planning approach of an IRP.

While Staff appreciates the Company's efforts to be a nimble and adaptive business amidst a changing energy landscape, Staff finds the "least regrets" approach in something as technical and granular to an overall business model as the residential basic charge structure to be to leave it as is. If the Company is able to clearly evidence that there are sufficient protections against exacerbating disproportionate burdens for environmental justice communities with this change, there may be merit to it at a future

point in time. However, until then, and in consideration of the significant dollar increase on its face, Staff does not support this change.

The last thing Staff would note regarding this particular topic is a concern that is broached in both Staff/1800 and Staff/900 regarding the Company's Line Extension Allowance (LEA) proposal. As Staff witnesses Mr. Shierman and Dr. Dlouhy explain, there is a level of ambiguity in the LEA changes that is not without consequences for customers. Specifically, the generous LEA, particularly when compared to relatively low volumetric gas prices, may not give customers full visibility into the uncertainty surrounding the future costs and risks of joining the gas system.[12] In this regard, the intersections of the LEA with the new premise premium adds a layer of complexity at best and deception at worst for new NW Natural customers.

While deferring to Dr. Dlouhy on the review and recommendations specific to the LEA, Staff believes that in the interest of socially just outcomes the Commission might look for least regrets actions to address the current state of uncertainty when considering the proposed residential rate design, given that:

1. Disparate impacts have not sufficiently been explored and mitigated; and
2. The proposed basic charge structure appears to offset the purported customer benefits of the LEA.

[12] Staff/900.

Q. Does Staff have additional comments regarding the residential rate design change?

A. Not at this time.

Q. Are there any other issues Staff wishes to raise on behalf of energy justice considerations?

A. Yes. The final issue Staff is prepared to raise at this time is a brief discussion on the overall impacts of this case on residential customer bills. Specifically, it is a known fact that environmental justice communities are disproportionately burdened by the energy system in general. This includes health disparities associated with pollution, proximity, and access to heating and cooling; as well as higher rates of energy burden, energy insecurity, energy poverty, and energy democracy.[13] What this means is that as certain components of the system change, such as costs recovered in rates, disproportionate burdens are worsened as the impacts of the changes are augmented for these communities.

Recall the discussion around energy burden and Table 2, displayed earlier in this testimony: as incomes draw nearer to zero, energy burden increases exponentially. Similarly, holding incomes constant, as rates increase, for households in the lowest rungs of the income distribution, energy burden increases exponentially. Noting that the magnitude of impact to residential customers in the Company's filing has already been assessed

[13] https://iejusa.org/section-1-defining-energy-justice/

by Staff as constituting rate shock for even the *average* non-energy burdened residential customer.

To this end, Staff is justifiably concerned about how the magnitude scales for environmental justice communities.[14] While the Residential Bill Discount Program is one tool available to address these higher burdens and impacts, Staff clarifies that this is not a comprehensive long-term affordability strategy, and the effects of Schedule 33 are limited to a customer's participation in the program.

In a review of the Company's most recently filed Bill Discount Quarterly Report[15] it appears that roughly six percent of NW Natural residential customers have enrolled in Schedule 33. Census estimates and poverty statistics generally show Oregon poverty levels between 12 to 20 percent with higher concentrations of persistent poverty in the Portland area.[16] Thus it is reasonable to infer that anywhere between 37,000 and 88,500 NW Natural customers are eligible for the Bill Discount Program but not enrolled, and thus expected to face even higher disproportionate energy burdens under the Company's proposal as filed.

Q. Has Staff proposed any changes to address this issue?

A. Staff witness, Eric Shierman has made recommendations to adjust the rate shock mitigation cap and ceiling tools in Staff/1800 (Rate Spread testimony)

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14 Staff/1800.
15 RG 102.
16 https://data.census.gov/profile/Oregon?g=040XX00US41; https://www.governing.com/community/oregon-has-44-census-tracts-in-persistent-poverty.

as one means of tempering the effects of the Company's proposal on certain customer classes. That said, these are adjustments on behalf of customer classes as a whole or on average and do not necessarily fully mitigate the disparate effects faced by environmental justice communities.

As such, for the purposes of this testimony, Staff encourages the Company to explore additional ways to increase the Schedule 33 saturation rate, OLIEE offerings, and future evolutions to differential rate designs in UM 2211. Further, this testimony supports accompanying Staff positions that thoughtfully adjust revenue requirement items downward both on the merits of the analysis and in this instance, in recognition of broad affordability concerns impacting all customers.

Q. Does Staff have other energy justice concerns that relate to the overall impacts of this case?

A. Yes. Staff has heard stakeholders raise concerns regarding the disproportionate health and safety impacts that the natural gas system has on environmental justice communities. Staff seeks to highlight these concerns and encourages the Company to fully examine these issues as it explores the future of the gas system in planning and rate making conversations.

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Staff/300
Scala/24

SUMMARY. STAFF RECOMMENDATIONS

Q. Please summarize your adjustments.

A. Staff has not made any specific recommendations that alter the Company's proposal which have not been discussed and summarized in other exhibits of Staff's Opening Testimony. That said, Staff has encouraged activities relative to promoting energy justice in this case and Company operations including:

- Continued and enhanced engagement of residential differential rate designs and programs, including discounts and energy efficiency/weatherization in UM 2211.
- Revisit the Schedule 335, Residential Bill Discount Program cost recovery for potential equity concerns.
- A discussion around the CEAG and the value of increased visibility and accountability.
- Continued consideration of how proposals disproportionately burden environmental justice communities, including the use of more granular customer segment analysis to inform strategies.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 490
WITNESS: Michelle Scala

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualifications Statement

April 18, 2024

Docket No. UG 490

Staff/301
Scala/1

WITNESS QUALIFICATIONS STATEMENT

NAME: Michelle Scala

EMPLOYER: Public Utility Commission of Oregon

TITLE: Energy Justice Program Manager
Strategy and Integration Division

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION: University of Hawaii, Manoa
Bachelor of Arts Economics

Bachelor of Arts Political Science
Concentration in Public Policy

EXPERIENCE: I have been employed by the Public Utility Commission of Oregon since July 2020 as a Senior Utility Analyst. I initially began work at the Commission in the then "Energy Rates, Finance and Audit Division" and transitioned to the Strategy and Integration Division upon its inception. In May of 2022, I was made Energy Justice Program Manager to the Utility Division where I lead energy equity work across utility rate, planning, and policy dockets. I have provided expert testimony as Commission Staff in general rate cases UE 394, UE 416, UE 426, UG 433, and UG 435, UG 461 and have consulted on others. I have over ten years of experience in policy analysis and program evaluation for state and local governments and received a graduate certificate in Public Administration in 2024. My work prior to the Commission included serving as a Senior Fiscal Analyst at the Oregon Department of Human Services and Economist at the Oregon Employment Department. Before coming to Oregon, I was employed at the Hawaii State Legislature as the Senior Budget and Policy Analyst to the Senate Committee on Ways and Means.

CASE: UG 490
WITNESS: MELISSA NOTTINGHAM

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 400

Opening Testimony
Public Comments

April 18, 2024

Docket No: UG 490 Staff/400
Nottingham/1

Please state your name, occupation, and business address.

A. My name is Melissa Nottingham. I am the Consumer Services and RSPF Manager. My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Staff Exhibit 401

Q. What is the purpose of your testimony?

A. To provide the public comments submitted by consumers pertaining to UG 490 with a brief summary of issues and/or concerns identified, and if applicable, refer to the Staff testimony addressing the public comment.

Q. Please explain the reasoning behind the inclusion of public comments in Staff's testimonies.

A. Consistent with the Commission's Internal Operating Guidelines as addressed in Order 20-065 in Docket No. UM 2055, to provide more transparency about the public comments in contested cases, public comments received are now made part of the Staff's Opening Testimony.

Please see Staff Exhibit 402 for comments received to date in this general rate case. Staff will also publish supplemental opening testimony on May 7, 2024, with incremental comments received including those received at Commission Public Comment Hearings on April 16, 2024 (virtual).

Written comments received after preparation of Staff's Opening Testimony will be included in subsequent Staff testimony. However, Staff will not be able to testify regarding comments received after Staff prepares its final

round of UG 490 testimony.

Presenting comments at a Commission Informational Hearing or through the Commission's website does not make the commenter a “party” to the proceeding or subject the commenting person to cross examination. Any party that has intervened in the proceeding may respond to Staff's summary of the public comments or the comments themselves in evidentiary testimony.

1. Summary of Comments

Q. How are public comments received by Staff?

A. Comments may be submitted via an online form, an email, a letter, or a telephone call. All comments submitted and published to the Commission’s webpage and are available for review. Please see: UG 490 NW NATURAL REQUEST FOR A GENERAL RATE REVISION .

Q. Please summarize the public comments received to date in this rate case.

A. Northwest Natural’s request for general rate increase has received nine comments.[1] Issues raised by consumers included the following:

a. Affordability and impact of higher rates and the impact to communities with limited incomes.

b. Support for continued decarbonization efforts.

c. Concern about operational costs including wholesale gas market.

Q. Are the public concerns addressed in Staff’s testimony for UG 490?

A. Yes. Affordability of rates is included in Charles Lockwood’s testimony, Exhibit

[1] Staff/402, public comments.

1200, and operational costs including salaries is included in Stephanie Yamada's testimony, Exhibit 2000.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 490
WITNESS: MELISSA NOTTINGHAM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 401

Witness Qualifications Statement

April 18, 2024

Docket No: UG 490

Staff/401
Nottingham/1

Witness Qualification Statement

Name: Melissa Nottingham

Employer: Public Utility Commission of Oregon

Title: Consumer Services and Residential Service Protection Fund (RSPF) Manager

Address: 201 High Street SE, Suite 400
Salem, Oregon 97301

Education: Bachelor of Arts in English, Arizona State University

Experience:

My employment at the Public Utility Commission began on May 1, 2022. During my tenure, I manage a team of 14 employees overseeing consumer complaints, the Oregon Lifeline Program, and the Telecommunication Devices Access Program. Part of my role includes sponsoring and participating in dockets related to Oregon Administrative Rules Division 21 and other consumer protection by regulated utilities in Oregon. I have provided testimony for UM 1908 and UM 2203, and provided comments for AR 653, UM 2237, and ADV 1391.

Prior to my employment at the Public Utility Commission, I worked for PacifiCorp for 25 years. PacifiCorp is a multi-jurisdictional regulated electric utility. From 2010 until my departure in 2022, I was a Regulatory Manager. My responsibilities included ensuring regulatory compliance in six states including Oregon. I provided testimony in general rate cases in six states focusing on the company's Schedule 300 fees and any company tariff modifications. Other duties included: representing the company in formal customer complaints and small claims court, overseeing contracts for new service for loads more than 1 megawatt, sponsoring modifications to the company's rules, and participating in each state's administrative rule dockets.

CASE: UG 490
WITNESS: MELISSA NOTTINGHAM

PUBLIC UTILITY COMMISSION
OF
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STAFF EXHIBIT 402

Opening Testimony
Public Comments

April 18, 2024

Docket No. UG 490

Staff/402
Nottingham/1

Public Comments Received on the Commission's Website

Jerry Crane Tigard	Is Executive Compensation at NWN tied to profitability and increases in the price of its common stock? How much has executive compensation increased in the last four years?
Jose Galindez Beaverton	Dry Natural Gas prices on the NYMEX today closed at $1.689/MMBtu, its lowest settlement value since July 22, 2020; a 19% drop in the contract during the past six days of price declines and down almost 80% from its mid-2022 highs which were in the $8 to $9 per MMbtu. How can the Commission continue to approve and justify ongoing increases for commercial and residential natural gas service when the cost of gas has dropped 80% reduction since its summer 2022 peak? Thanking you in advance Jose
Paul Chantiny North Bend	Fighting climate change requires us all to shoulder a part of the burden. If we increase the cost of a commodity, won't consumption decrease? Therefore, why isn't Oregon PUC sharply increasing the price of natural gas?
David McNeel Oregon City	Hi there, figuring out your form is impossible for the average Oregonian. I am sure that the Commission wants it that way. I have lived in Oregon all of my 70 years. None of the climate mandates by Kate Brown have ever been voted on by the citizens of Oregon. So, go ahead and jack the electric utility rates to infinity and tax natural gas until the average Oregonian can't afford it. Fortunately, the Oregon climate grows trees very well and Oregonians know how to drop trees by the thousands and split them into firewood. Nothing like a hot fire in the dead of Winter. This Commission and the Climate Crazies think you have all of the answers. You will soon find out how wrong you are. This issue is no different than the tolling of Oregon Highways. Tina Kotek punted tolling to the Oregon Legislature like a hot potato! The PUC is next.
Callie Sacarelos Portland	Consumer group asks Oregon regulators to dismiss new PGE rate hike request: https://www.oregonlive.com/environment/2024/03/consumer-group-asks-oregon-regulators-to-dismiss-new-pge-rate-hike-request.html 5 takeaways: Why are Oregon power rates going up so fast? https://www.oregonlive.com/environment/2024/03/5-takeaways-why-are-oregon-power-rates-going-up-so-fast.html Why are Oregon electric, gas rates going up so fast? https://www.oregonlive.com/environment/2024/03/why-are-oregon-electric-gas-rates-going-up-so-fast-beat-check-podcast.html Oregon's second-largest utility seeks big rate hike, again. Here's why.

	https://www.oregonlive.com/environment/2024/02/oregons-second-largest-utility-seeks-big-rate-hike-again-heres-why.html PGE wins approval for largest rate increase in two decades: https://www.oregonlive.com/business/2023/11/pge-customers-will-pay-more-for-electricity-in-2024.html Here's how much PGE, Pacific Power electric bills will increase starting January: https://www.oregonlive.com/business/2023/12/heres-how-much-pge-pacific-power-electric-bills-will-increase-starting-january.html PacifiCorp wants state to protect it from future wildfire lawsuits. Past victims are disgusted: https://www.oregonlive.com/business/2023/11/pacificorp-wants-state-to-protect-it-from-future-wildfire-lawsuits-past-victims-are-disgusted.html Pacific Power seeking 12.2% rate increase in 2023: https://www.oregonlive.com/business/2022/03/pacific-power-seeking-122-rate-increase-in-2023.html Here's how much your electric bill is going up in January: https://www.oregonlive.com/business/2023/01/brace-yourself-heres-how-much-your-electric-bill-is-going-up-in-january.html Portland leaders inch up water rates they just cut, citing desire to aid low-income renters: https://www.oregonlive.com/politics/2023/05/portland-leaders-inch-up-water-rates-they-just-cut-citing-desire-to-save-program-to-aid-low-income-renters.html NW Natural's proposed rate hike unfairly saddles customers with costs of bonuses, profits: https://www.oregonlive.com/opinion/2022/03/opinion-nw-naturals-proposed-rate-hike-unfairly-saddles-customers-with-costs-of-bonuses-profits.html Oregon natural gas utility can't ask customers to pay for political spending, new pipelines: https://www.oregonlive.com/environment/2023/10/oregon-natural-gas-utility-cant-ask-customers-to-pay-for-political-spending-new-pipelines.html Oregon gas company using ratepayer money to fight state climate program: https://www.oregonlive.com/business/2023/07/oregon-gas-company-using-ratepayer-money-to-fight-state-climate-program.html Get ready, your NW Natural gas bill's going up: https://www.oregonlive.com/business/2019/11/get-ready-your-nw-natural-gas-bills-going-up.html PacifiCorp may ask utility regulators to let it pass wildfire litigation costs to customers: https://www.oregonlive.com/business/2023/06/pacificorp-may-ask-utility-regulators-to-pass-its-wildfire-litigation-costs-to-customers.html Amid ongoing pandemic, Portlanders will pay more for water and sewage:

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Staff/402
Nottingham/3

	https://www.oregonlive.com/news/2021/02/amid-ongoing-pandemic-portlanders-will-pay-more-for-water-and-sewage.html PGE says ill-conceived trades cost the utility at least $104m; stock slides 8.3%: https://www.oregonlive.com/business/2020/08/pge-says-ill-conceived-trades-cost-the-utility-at-least-104-million-stock-slides-83.html
Jennifer Priest Portland	Thank you a million times to the PUC for standing up to the gas companies! https://www.opb.org/article/2024/03/15/oregon-natural-gas-companies-fail-approval-climate-action-plans/
Patel Neel Portland	Hello! My name is Neel Patel and I live in Portland, OR (97209). I write to express my concern about methane pollution from our utilities and discuss how the Oregon Public Utilities Commission can play a clean role in decarbonizing our grid. I first want to thank you for all the work you have done so far. I read on OPB that you are keeping the pressure on the 3 natural gas companies in Oregon to comply with our greenhouse gas emission reduction goals. I commend you three (Ms. Decker, MS Tawney, and now Mr. Perkins) on this climate focused action. These companies will try everything they can do to keep using methane when a rapid reduction in methane is one of the best things we can do right now to fight the climate crisis. From your actions, it is clear that you understand the issues with methane- the 80x global warming effect compared to carbon dioxide, the abundance of leaks in the supply chain, and the public health and safety risks, including explosions, degraded indoor air quality, and worsening respiratory conditions. As a physician in our community (I am a radiologist at OHSU), I am particularly concerned about how climate change and fossil fuel pollution interact to worsen human health and wellbeing. We are already feeling the climate change related health effects today: increased extreme weather, more heat related illnesses, asthma and respiratory diseases from particular pollution, and tropical diseases expanding from the tropics (like Dengue in Puerto Rico and Florida). Methane gas usage is particularly harmful. A peer reviewed study (PMID: 36612391) found that gas stove use indoors is attributable to 12.7% of childhood asthma. These effects will only get worse unless we can decarbonize quickly and effectively. Natural gas companies and other fossil fuel companies will continue to spread misinformation to downplay the climate and health risks to the detriment of regular Oregonians and to the benefit of their bottom line. However public utilities like Oregon's should keep the pressure up to force them to make changes to reduce emissions that will benefit all of us, including the people that work at those companies! I urge you to take strong action in regulating methane emissions from utilities, like

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Staff/402
Nottingham/4

	imposing stricter leak detection standards, efficiency requirements for aging gas infrastructure, or rate-setting and rules that help incentivize cleaner sources of electricity. You can also impose regulations that encourage the switch from gas heating and cooking to electrification. Thank you for your hard work so far and keep up the fight to decarbonize our grid. -Neel Patel, MD
Graham Williams	Strongly oppose! How can we live in this state with your tax tax tax and now increase in electric & water & gas!??? We are all fed up! If we leave the state guess what - you get NO revenue
Kate Fuller	No increase! We are in our 70s, on a fixed income and this would raise our bill by $40 each month. NW turned off the gas while my husband was in cancer treatment. Left a card but never bothered to knock on the door. I prefer a 20% DECREASE please.

CASE: UG 490
WITNESS: David Abraham

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 500

Opening Testimony
Gas Storage Operating Expense, Gas Storage in Rate Base, and Major Storage Projects.

April 18, 2024

Docket No: UG 490

Staff/500
Abraham/2

Q. Please state your name, occupation, and business address.

A. My name is David Abraham. I am a Senior Economist employed in the Rates, Safety and Utility Performance Program of the Public Utility Commission of Oregon (OPUC or Commission). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/501.

Q. What is the purpose of this testimony?

A. My testimony presents Staff's analysis and recommendations regarding the rate treatment of gas storage operating expense, gas storage in rate base, and major storage projects.

Q. Did you prepare any other exhibits for this docket?

A. Yes. NWN's non-confidential responses to select data requests can be found in Exhibit Staff/502.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Gas Storage Operating Expense 3
Issue 2. Gas Storage in Rate Base 9
Issue 3. New Plant – Major Storage Projects 13

Docket No: UG 490

Staff/500
Abraham/3

ISSUE 1. GAS STORAGE OPERATING EXPENSE

Q. What is NWN's gas storage operating expense?

A. NWN's gas storage operating expenses are related to the Company's underground and Liquid Natural Gas (LNG) storage facilities. The storage facilities allow NWN to store lower summer-priced natural gas to be used in the winter during high demand or peak day events. Like transportation, unneeded gas storage capacity can be optimized by selling into a future higher priced market. NWN records gas storage operating expenses in Federal Energy Regulatory Commission (FERC) Accounts 816 through 847, as detailed in the Company's filing.[1]

Q. Please summarize NW Natural's proposal related to gas storage operating expense.

A. The Company is proposing a non-labor Test Year gas storage operating expense of $6,210,300, on a total system basis, or $5,529,651 on an Oregon allocated basis.[2] NWN's gas storage forecast was developed using the Base Year spend multiplied by a Consumer Price Index (CPI) factor of 3.6 percent in 2024 and 2.9 percent for the 10 months in 2025. The Company also identified items that were adjusted according to their specific estimated increase or decrease.[3]

Q. Did Staff analyze if the cost of gas is included in base rates?

[1] NW Natural/1401, Davilla/1.
[2] Staff/502, NWN response to Staff DR 193, Attachment 1, Second Amended.
[3] NWN/1400, Davilla/8.

A. The annual Purchased Gas Adjustment (PGA) filing revises rates to include the forecasted cost of gas for the upcoming year through a mechanism outside of base rates. As a result, cost of purchased gas is addressed in the annual PGA rather than in a General Rate Case (GRC).[4]

Q. Did Staff analyze the Company's use of CPI factors to develop the Test Year gas storage expense?

A. Yes. NWN obtained the Western CPI factors used to develop the Test Year from the Oregon Office of Economic Analysis (OEA) as reported in the September 2023 Oregon Economic and Revenue Forecast. Staff recommends using the all-urban CPI. In addition, the OEA has since issued an updated forecast in March of 2024 and the new all-urban CPI factors are 2.7 percent for 2024 and 2.0 percent for 2025.

Q. Has Staff determined what the impact would be to the Company's Test Year gas storage expense if the updated CPI factors were used?

A. Yes. Staff has calculated the Oregon allocated non-labor gas storage expense would be reduced by $79,816 by using the updated all-urban CPI factors released by the OEA in March of 2024.

Q. What else did Staff consider regarding NWN's gas storage operating expense?

[4] NWN/1700, Wyman/21.

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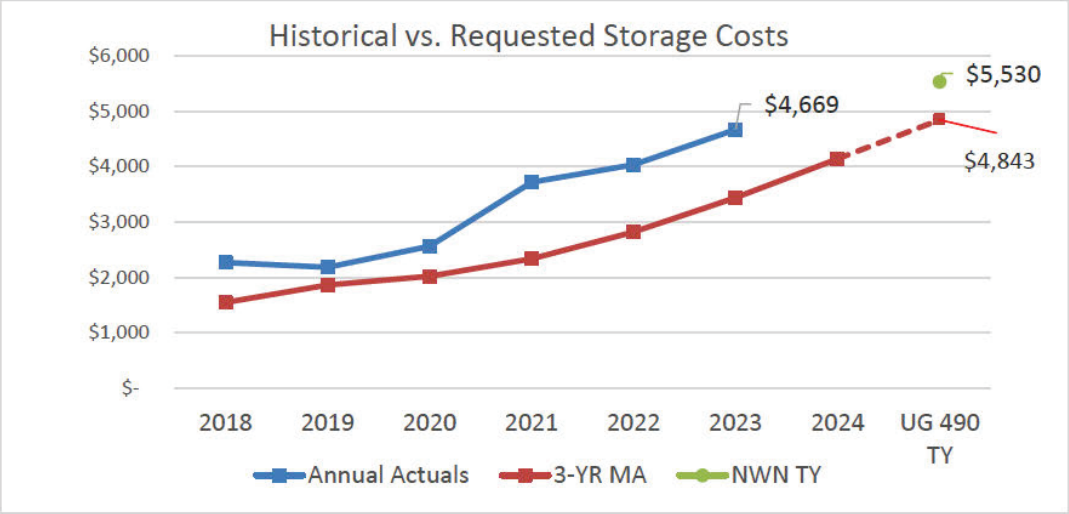
Staff/500
Abraham/5

A. Staff analyzed historical data provided by the Company in response to Data Request 193 and in the Company's supporting work papers.[5] Staff calculated a three-year moving average of Oregon allocated gas storage costs compared to the Test Year gas storage expense requested by the Company. The proposed Test Year dollar value of non-labor gas storage costs included in the filing and the Company's historic gas storage costs are summarized in Figure 1.

Figure 1 – Value of Historic vs Requested Gas Storage Costs ($000)



Q. Describe Staff's analysis regarding Test Year gas storage costs.

A. Staff's practice is to compare the previous three years' expense and longer-term trends to the requested Test Year amount, relying more heavily on recent trends unless there is a reason not to do so.[6] Staff extended the 2024 three-year moving average trend-line to compare to the Test Year request proposed

[5] NWN/Exhibit/1400/Davilla/Workpaper. See also NWN's response to Staff DR 193, Attachment 1, Second Amended.
[6] See UE 388, Staff/300/3.

by the Company by obtaining the year-over-year moving average growth in gas storage expense from 2023 to 2024 and then adding that increase to the 2024 moving average.

Q. What does Staff's comparison of the Company's Test Year gas storage costs to historical averages show?

A. The extended moving average trend-line, displayed in Figure 1, indicates the Company's Test Year amount would have to be reduced by $686,504 to align with the moving average trend.

Q. Did Staff identify any expenses related to the expansion of gas storage capacity in the Company's Test Year request that would explain why NW Natural's proposed Test Year expense exceeds what would be expected based on historical spend?

A. Staff did not identify any projects at the Mist facility, or any of the Company's LNG storage terminals, that provided for the expansion of gas storage capacity. However, the Company will be initiating rig-based casing inspections in 2024 to satisfy the conditions of 49 CFR 192.12(d)(3).[7] The Well Casing Integrity Inspection Program (FERC 832) is required to address safety issues related to downhole facilities, including wells and casings at underground natural gas storage facilities. The Company estimates the Test Year expense for the casing inspection program to be $625,000, on a total system basis, and $556,000 on an Oregon-allocated basis.

[7] NWN/1400, Davilla/10.

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Staff/500
Abraham/7

Q. Describe Staff's analysis regarding rig-based casing inspection expenses.

A. NWN's rig based integrity inspection program requires additional operating costs that were not included in the historical moving average but will be incurred during the Test Year. Applying the extended three-year moving average alone would under-estimate the expected Test Year gas storage expense.

Q. Does Staff recommend including the rig-based casing inspection expenses in the Test Year adjustment?

A. Staff proposes that the rig-based casing inspection expense should be included as an off-set to the trend adjustment.

Q. Please summarize Staff's proposed adjustment to NWN's Test Year gas storage operating expense.

A. Staff proposes an Oregon allocated Test Year adjustment that will reduce NWN's requested gas storage operating expense by $210,320. As discussed above, the Company's Test Year expense is higher than what appears reasonable based on a comparison to historical amounts. The Company has explained why the forecasted costs are increasing, but its explanation does not support the full amount of the increase. Table 1 displays a summary of Staff's recommended adjustments to NWN's Oregon-allocated gas storage expense.

Docket No: UG 490

Staff/500
Abraham/8

TABLE 1. EFFECT OF STAFFS ADJUSTMENTS

Staff's Recommended Adjustments	Oregon Allocation
Staff Reduction due to Updated CPI Factors	$ (79,816)
Staff Reduction - Alignment to Historical Trend	$ (686,504)
Off set to Trend Due to Well Inspection Program	$ 556,000
Staff's Total Adjustment to NWN's Test Year Request	**$ (210,320)**

Staff's recommendation would reduce NWN's Oregon-allocated Test Year gas storage operating expense from $5,529,651 to $5,319,331.

Docket No: UG 490

Staff/500
Abraham/9

ISSUE 2. GAS STORAGE IN RATE BASE

Q. Please describe the gas storage costs at issue.

A. Storage gas consists of two components, "cushion gas" and "working gas inventory." "Cushion gas" is permanently retained in storage to maintain operational pressure and prevent water deterioration in an underground storage reservoir. "Working gas inventory" is the gas that flows in and out of the storage reservoir, or Liquid Natural Gas (LNG) tank, to serve customer loads.

Q. Please summarize NW Natural's proposed Test Year gas storage costs included in rate base.

A. NW Natural included a total of $43,888,538 for Oregon allocated gas storage in the Test Year rate base, of which $20,217,645 is cushion gas and $23,670,893 is working gas.[8] NW Natural's Oregon allocated working gas amount for the twelve-month Base Year period ending September 30, 2023, is $63,623,317. NWN's Test Year gas storage expense represents a 45.5 percent decrease compared to the Base Year.

Q. Please summarize the Commission's historical treatment of gas storage in rate base.

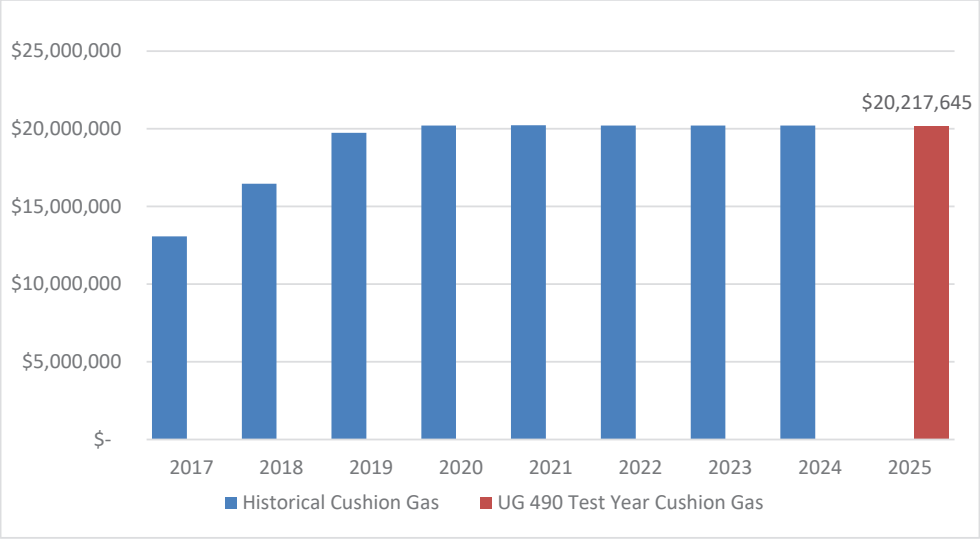
[8] NW Natural workpaper "UG 490 - Exhibit 1713 – WP2 – Other Rate Base Items", tab "Cushion Gas", rows 149-156.

A. All three regulated gas utilities serving in Oregon currently include these costs in rate base as a result of stipulations reached by the Parties and adopted by the Commission.[9]

Q. Please explain how Staff analyzed cushion gas costs in rate base.

A. Staff expects cushion gas volumes to remain constant unless there is a major expansion of storage. Typically, the value of cushion gas value is based on its cost when injected into the facility and should change very little in the absence of expansions. The proposed dollar value of cushion gas included in the filing, and the historic value of the Company's cushion gas is summarized in Figure 2.

Figure 1 - $ Value of Historic vs Requested Cushion Gas



Q. Does Staff propose any adjustments to cushion gas inventory included in Rate Base?

[9] See e.g., *In* the *Matter of Northwest Natural,* Order No. 13-349 at 5 (Commission adopting stipulation including NW Natural Gas Company's working gas inventory in rate base).

A. No. Staff does not propose any adjustment to cushion gas inventory in rate base at this time and is satisfied that the amount included in the Test Year filing is appropriate.

Q. Please explain how Staff analyzed working gas costs in rate base.

A. Staff analyzed historic data provided by the Company's supporting work papers.[10] The Company used the model "Sendout" to predict its gas prices and storage volumes by month for each storage asset. The requested $23,670,893 in working gas represents Oregon's share of the 13-month average of monthly averages (AMA) of the predicted inventory value in the Test Year.[11] Staff calculated the dollar amount for the working gas inventory in rate base using the 13-month AMA historical balances and a three-year calendar annual moving average. The proposed dollar value of working gas included in the filing, and the historic value of the Company's working gas is summarized in Figure 3.

Q. What are Staff's findings based on its analysis of working gas costs in rate base?

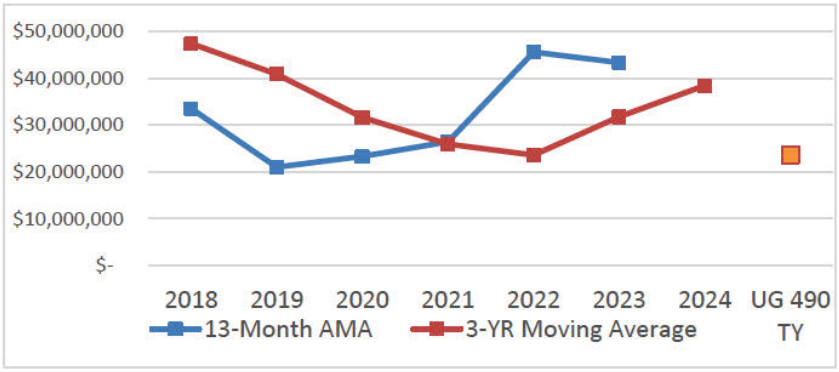
A. Staff found that the Company's requested $23.7 million for Oregon allocated working gas is below the most recent calendar year 13-month AMA and the three-year moving average. NW Natural's working gas request represents a decline of 45.5 percent compared to the 2023 base case.

[10] NW Natural workpaper "UG 490 - Exhibit 1713 – WP2 – Other Rate Base Items", tab "Cushion Gas", rows 146-156.
[11] Ibid.

Docket No: UG 490

Staff/500
Abraham/12

Figure 2 - $ Value of Historic vs Requested Working Gas[12]



Q. Please summarize Staff's proposed adjustment to Gas Storage in Rate Base.

A. Staff proposes no adjustment to either working gas or cushion gas at this time and recommends allowing the total amount of $43,888,538 for Oregon allocated gas inventory in the Test Year, as requested by NW Natural.

[12] Values presented on an Oregon basis.

Docket No: UG 490

Staff/500
Abraham/13

ISSUE 3. NEW PLANT – MAJOR STORAGE PROJECTS

Q. Please summarize Staff's analysis of NWN's major gas storage projects.

A. NWN's gas storage facilities include Portland LNG, Newport LNG, and Mist. Although this rate case includes maintenance and inspection projects related to all three storage facilities, Staff did not identify any major gas storage additions to the Company's overall storage capacity.

Q. Please summarize Staff's analysis of the Mist storage facility projects.

A. Staff identified several projects related to the Mist facility, which is an underground storage facility located in Mist, Oregon. In response to a Turbine Compressor Study completed in December 2022, the Company implemented the Mist GC500 Turbine Compressor Cold Spare Project and the Mist GC600 Turbine Compressor Cold Spare Project. The Company expects to complete both projects by October 2024. The cost estimate for both projects is approximately $4.8 million on an Oregon allocated basis.[13] The Mist Electrical Upgrades Project Phase 2 will replace end-of-life equipment and will cost approximately $2.0 million. The Mist Methanol Injection Project at I/W Wells will replace existing methanol tanks and injection systems and will cost approximately $4.1 million. Finally, the Mist Instrument and Controls Project will cost approximately $2.2 million.[14]

[13] NWN/500, Kizer/24.
[14] NWN/500, Kizer/30.

Q. Did Staff identify any other gas storage projects included in the filing?

A. Yes. The Portland LNG Plant will undergo a Valve and Controls Replacement Project, estimated to cost approximately $3.8 million, a Boil-Off Compressor Project estimated to cost approximately $4.2 million, and a Pretreatment Improvement Project estimated to cost approximately $2.3 million.[15] The Newport Plant includes a T-1 Tank Improvement Project, which implements the recommendations made in the Newport LNG Tank Study and includes a cost estimate of approximately $3.2 million, on an Oregon-allocated basis.[16]

Q. Does Staff recommend any adjustments to NWN's new plant additions for gas storage projects?

A. No. Staff did not identify any new plant additions that expanded storage capacity in this filing and has no proposed adjustments for gas storage projects included in this rate case at this time.

Q. Does this conclude your testimony?

A. Yes.

[15] NWN/500, Kizer/34.
[16] NWN/500, Kizer/41.

CASE: UG 490
WITNESS: DAVID ABRAHAM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 501

Witness Qualifications Statement

April 18, 2024

Docket No. UE 490

Staff/501
Abraham/1

WITNESS QUALIFICATION STATEMENT

NAME: David Abraham

EMPLOYER: Public Utility Commission of Oregon

TITLE: Energy Costs Section Economist
Rates, Safety and Utility Performance Program

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION: Master of Science, Economics
University of Texas,
El Paso, TX

Bachelor of Arts, Business Administration
University of Texas,
El Paso, TX

EXPERIENCE: I have been employed by the Oregon Public Utility Commission as an economist in the Energy Costs Section since November 2023. Prior to working for the Commission, I worked for an Investor-Owned Electric Utility in Texas beginning in 2009. I started with the utility as a real-time energy trader and transitioned into the Regulatory and Resource Planning Department in 2019. Within the planning department, I served as lead-forecaster and was responsible for producing the company's long-term energy forecast. I also prepared weather normalization schedules for regulatory filings and financial reconciliations. In 2019, I attended an electric utility ratemaking course offered through New Mexico State University and the Center for Public Utilities.

CASE: UG 490
WITNESS: DAVID ABRAHAM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 502

Exhibits in Support
Of Opening Testimony

April 18, 2024

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 193
Regarding gas storage expenses:

a. Please indicate whether gas storage expenses are included in the test year. Please provide a separate response for each of the following gas storage expense types:
    i. Underground gas storage,
    ii. LNG gas storage, and
    iii. Other gas storage.
b. If yes to (a), please provide a narrative explanation of how gas storage expenses are forecasted for the Test Year, providing copies of all underlying data used in the forecast in electronic workbook format, and providing references to where the forecast appears in the Company's workpapers. Please provide a separate response for each of the gas storage expense types listed under(a).
c. If yes to (a), please provide, in a single electronic spreadsheet format, for each calendar year from 2011 through 2022, and monthly through 2023, the Company's gas storage expenses. Please provide a separate response for each of the gas storage expense types listed under section (a), as well as a breakdown of the expenses into:
    i. Supervision and engineering,
    ii. Fuel,
    iii. Other equipment, and
    iv. Other expenses.

In response to (c), please separately identify any related labor expense and provide results separately for total company and for Oregon.
Please provide only those categories included in the Company's filing in this response (excluding categories which flow through the PGA).

Amended Response:

Please see "UG 490 OPUC DR 193 Attachment 1 Second Amended" data that only includes non-payroll.

CASE: UG 490
WITNESS: LAUREL ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 600

Opening Testimony
Plant in Service

April 18, 2024

Docket No: UG 490

Staff/600
Anderson/1

Q. Please state your name, occupation, and business address.

A. My name is Laurel Anderson. I am a Senior Telecommunications Analyst employed in the Rates, Safety and Utility Performance Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/601.

Q. What is the purpose of your testimony?

A. My testimony addresses the Company's proposed additions to rate base for new plant.

Q. Did you prepare any exhibits for this docket?

A. No.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1: Utility Plant in Service 2
Issue 3: Test Year Rate Base/Discrete vs. Non-Discrete Investments 6
Issue 4: New Plant Major Distribution Projects 9
Issue 5: New Plant – Resource Centers 14
Issue 6: Attestations and Proposed Project Adjustments 18

Docket No: UG 490

Staff/600
Anderson/2

ISSUE 1: UTILITY PLANT IN SERVICE

Q. Please define how NW Natural (NWN or Company) calculated Utility Plant in Service.

A. NWN starts with actual plant account balances as of September 30, 2023. It then forecasts additions, retirements, and transfers for all FERC accounts. As future plant balances are then developed, depreciation expense associated with each asset class can be calculated. Consistent with mass-asset accounting, both the gross plant and accumulated depreciation amounts are lowered to reflect forecasted asset retirements.

Q. Please summarize the amount and timing of the company's utility Plant in Service as proposed in the initial filing.

A. The Company is proposing utility plant in service of $4.121 billion dollars and accumulated depreciation of $1.639 billion, yielding a net utility plant of $2.482 billion[1] as of October 31, 2025, the end of the test year.

Q. Explain Staff's findings regarding how the Company calculated the amount for its Plant in Service.

A. Staff review of the underlying work paper indicates this amount is calculated using plant forecasts of plant in the November 1, 2024 to October 31, 2025, Test Year.[2] Staff notes that the Company's work paper detailing the increase in rate base is confidential in part.

1 NW Natural/1713, Walker/1.
2 NW Natural/1700, Walker/28.

Q. Please discuss the portion of rate base projections deemed to be confidential.

A. The Company states that "[a]ll data past September 30, 2023, or contained therein" is confidential. As stated in the UG 388 case, "All forward looking monthly data that has not been disclosed to the public has been deemed confidential."[3]

Q. Please discuss Staff's ongoing objection to a portion of rate base projections being designated as confidential.

A. In Staff's view there is a public policy issue here, as the Commission seeks to have as much transparency as possible in its activities.

Q. Please discuss the Company's methodology for developing utility plant estimates.

A. According to the Company's filing, the overall methodology can be summarized as follows:

- **Intangible – Software** (FERC Accts. 303.1 to 303.7) are allocated between Oregon and Washington on the basis of "all customers" allocation factor.[4]
- **Intangible – Other** (FERC Accts. 301 and 302) are specific to Oregon and Washington with no allocation between states.
- **Production** (FERC Accts. 304.1 to 319) are specific to Oregon and directly assigned.

[3] UG 388 Staff/200, Fox/2.
[4] NW Natural/1700, Walker/41.

- **Transmission** (FERC Accts. 365.1 to 367 and Acct. 369) are state situs and therefore are specific to Oregon.
- **Distribution** (FERC Accts. 374.1 to 387.3) are specific to Oregon and Washington with no allocation between states.
- **General** (FERC Accts. 390.1 to 398.5) are allocated using a 3-Factor & Direct method.
- **Storage and Storage Transmission** (FERC Accts. 350.1 to 363.42, and Accts. 367.21 to 367.26) are allocated based on Oregon's share of Firm Delivered Volumes.[5]
- **Land & Structures** (FERC Accts. 389 and 390) are allocated using a more detailed methodology further discussed below.
- **CNG/LNG Refueling Facilities** (FERC Accts. 363.5 and 363.6) are allocated using a 3-Factor method.

Q. Does Staff agree with the Company's calculation and methodology regarding its Plant in Service?

A. Yes. Staff agrees with the Company's methodology, which is consistent with prior rate cases.

Q. Does Staff propose any adjustments?

[5] The allocation methodology also includes a specific adjustment to allocate $33 million of the total South Mist Pipeline Extension to Oregon as agreed in a prior rate case. See the Company's Direct Testimony in UG 152 (UG 152/NWN/400 Stinson at pages 20 – 22) and NWN Advice No. 04-11A.

A. Yes, Staff proposes to remove plant additions that come on-line subsequent to the rate effective date. Staff discusses this in more detail below, along with the proposed amounts to be removed.

Docket No: UG 490

Staff/600
Anderson/6

ISSUE 2: TEST YEAR RATE BASE
DISCRETE VS. NON-DISCRETE INVESTMENTS

Q. Please define the difference between "discrete" and "non-discrete" expenditures.

A. Discrete investments are investments the Company has proposed and planned to implement to fulfill a specific operational aim, or to address a specific operational issue. Discrete projects tend to fall into subcategories of System Betterments, System Reinforcement Projects, Information Technology, and Land and Structures. Costs of discrete projects can vary widely year over year.

The second category can be thought of as "non-discrete capital expenditures," in which the Company generally does not exercise much discretion. These investments include Public Works, Relocates, Damages, Transportation and Equipment, Tools, Technical Refresh, Leakage, Customer Growth, Transmission Integrity Management Program ("TIMP"), and Distribution Integrity Management Program ("DIMP")

Q. Please discuss the discrete and non-discrete projects the Company plans to add to the rate base, and seek recovery in this case.

A. The Company seeks to add to rate base all capital expenditures completed since the Company's last rate case, UG 435, that will be used and useful as of the rate effective date of this case – November 1, 2024. NW Natural also

seeks to add all capital expenditures, both discrete and non-discrete that will be completed during the Test Year.[6]

Q. Please discuss Oregon's "used and useful" standard.

A. ORS 757.355 specifies that before costs of utility plant used to serve customers can be included in utility rates, the plant must be in service. Accordingly, property must be in service prior to the effective date of the rates.[7,8] The law applies to all utility plant including plant placed into service before the rate effective date and prior additions to rate base that are no longer used in providing utility service to customers.

Q. Does the Company's filing include discrete investments that will go into service after the rate effective date?

A. Yes. The Company included the North Coast Feeder Uprate project – Section B, which is expected to go into service in December 2025, after the rate effective date of November 1, 2024. As such the capital costs associated with this project should be removed from the revenue requirement.

Q. Does the Company's filing include non-discrete investments that will go into service after the rate effective date?

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6 NW Natural/1400, Davilla/22.

7 ORS 757.355 prohibits the inclusion of property not presently used for providing utility service to the customer.

8 *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, UE 210, Order No. 10-022, p. 14 (January 26, 2010) ("ORS 757.355 prohibits a public utility from collecting in customer rates the costs of any property not presently used for providing utility service to those customers. . . .Given this evidence, and despite the parties' contentions about specific rate base adjustments, it is clear that the Stipulation will allow Pacific Power to collect in rates only the costs of property presently providing service to customers in conformance with ORS 757.355. We therefore deny ICNU's objection on this point.").

A. Yes. As noted above, the Company includes all capital investment in the Test Year, which is the twelve months following the rate effective date. Staff recommends the Commission include the non-discrete investment in retail rates. An incremental portion of the investment will be on-line each month, so monthly customer rates would not include costs of plant not in service.

Docket No: UG 490

Staff/600
Anderson/9

ISSUE 4: NEW PLANT MAJOR DISTRIBUTION PROJECTS

Q. Which major distribution projects removed from Docket No. UG 435 have been completed since the Company's 2022 rate case?

A. In its last rate case, the Company agreed to remove the E04 - 6 and 8 inch ILI Conversion Project, the Natural Forces Projects, the Newport Switchgear Replacement Project, the TBD1845 Fire System Upgrade Project (subsequently renamed the Mist Fire System Upgrade Project), and the Mist GC 500 Human-Machine Interface ("HMI") and Controls Project because they were not scheduled to be placed in service by October 31, 2022.[9]

Q. Please provide an update on the status of these projects.

A. The Company completed and placed in service the E04 – 6- and 8-inch ILI Conversion Project in December 2023, the Mist Fire System Upgrade Project in December 2023, the Newport Switchgear Replacement Project in July 2023, and the Mist GC 500 HMI and Controls Upgrade Project in May 2023. These projects are included in plant in the base year ended October 31, 2023.

Q. Please identify the significant distribution system projects included in the current rate case.

A. The Company is requesting recovery for the following significant distribution system projects:

- North Coast Feeder Project;[10]

[9] NW Natural/500, Kizer/2.
[10] NW Natural/500, Kizer/5-8.

- Tualatin-Sherwood Road Grading Project (the actual costs exceeding those already being recovered in rates);[11]
- P30 Willis Creek HDD Install Project;[12] and
- SE Gate Station Rebuild Project.[13]

Q. Please describe the North Coast Feeder Project

A. In 2018, the Company identified a potential pressure drop in the Northwest area of its service territory in violation of the Company's system reinforcement standards. To address this and other pressure drops the Company presented the North Coast Feeder Uprate Project for acknowledgement in its 2018 Integrated Resource Plan ("IRP") Update 3 filed in docket LC 71 on March 1, 2021. The Company has collected data revealing significant pressure drop violations which pose an unacceptable risk to safety and reliability.

Modeling indicated that, if left unmitigated, pressure drops could potentially reach 0 pounds per square inch gauge ("psig"). To mitigate observed and potential drops in pressure the Company proposed the North Coast Feeder Uprate Project: (1) uprating 6.6 miles of high pressure gas main on one section of its system between the Walluski district regulator and Rodney Acres Road from a maximum allowable operating pressure ("MAOP") of 175 psig to a MAOP of 575 psig ("Section A"); and then uprating another 22.2 miles of high pressure gas main on another section of its system from

[11] NW Natural/500, Kizer/8-11.
[12] NW Natural/500, Kizer/11-12.
[13] NW Natural/500, Kizer/12-13.

Warrenton to Cannon Beach from MAOP of 175 psig to a MAOP of 390 psig ("Section B").

Q. What is the timing and estimated cost to complete the North Coast Feeder Project?

A. The North Coast Feeder Uprate Project Section A is expected to be placed in Service in September 2024 at an expected cost of $8.2 million. Section B is expected to be completed in December 2025 at a cost of $6.4 million.[14]

Q. Please describe the Tualatin-Sherwood Road Grading Project.

A. The Tualatin-Sherwood Road Grading Project relocated approximately 6,400 feet of six-inch high-pressure main, approximately 11,000 feet of 4-inch main, three district regulators and two telemetry facilities on Tualatin-Sherwood Road.

Q. Please describe the additional cost recovery the Company is requesting for the Tualatin-Sherwood Road Grading Project.

A. The Tualatin-Sherwood Road Grading Project was included in the Company's last rate case (UG 435), the Commission-authorized revenue requirement in that case included a forecasted amount of $2.6 million and the actual cost stated in the attestation was $7.0 million. Only $2.6 million was included in the rate base in UG 435. The actual final cost is approximately $9.1 million.[15]

Q. Please explain why final cost for the Tualatin-Sherwood Road Grading Project increased from $7 million to $9.1 million.

[14] NW Natural/500, Kizer/8.
[15] NW Natural/500, Kizer/10.

A. According to the Company, the final impact to NW Natural facilities and the scope of relocation was not known during the processing of UG 435. Material changes to Washington County's roadway design and schedule beyond the Company's control drove increased construction costs for this project. Due to conflict with other utilities, the County did not permit NW Natural to install mains in the public utility easement. The design change required the new mains to be located within the existing roadway resulting in significantly higher costs.[16]

Q. What is the Company requesting for the Tualatin-Sherwood Road Grading Project in the current rate base?

A. The Company is requesting the recovery of $6.5 million, which is the difference between the initial amount estimated and the total actual costs incurred by the Company to complete the Tualatin-Sherwood Road Grading Project and place it in service.[17]

Q. Please describe the P30 Willis Creek HDD Install Project.

A. The P30 Willis Creek HDD Install Project entails relocating and lowering the P30 transmission pipeline via an HDD installation to mitigate the risk of rupture because of a potential landslide in the Willis Creek area. The Company submitted this project to bid in August 2023. Based on feedback from contractors the proposed solution was not constructable. Based on this

[16] NW Natural/500, Kizer/10.
[17] NW Natural/500, Kizer/11.

feedback, the project is being redesigned with a scheduled construction timeframe of Summer 2024.

Q. What is the Company seeking to recover for the P30 Willis Creek Project?

A. The estimated total cost to complete the P3 Willis Creek HDD Install Project is $3.5 million.[18]

Q. Please describe the SE Gate Station Rebuild Project

A. The SE Gate Station Rebuild Project involves replacing piping, valves, the line heater and station regulation, updating telemetry and controls, and installing a check meter and coalescing filter to improve the gate stations operation, safety, efficiency, and compliance.

Q. What is the timing and estimated cost to complete the SE Gate Station Rebuild Project?

A. The SE Gate Station Rebuild Project is expected to be placed in Service in October 2024 at an estimated cost of $2.3 million.[19]

[18] NW Natural/500, Kizer/12.
[19] NW Natural/500, Kizer/13.

Docket No: UG 490 Staff/600
Anderson/14

ISSUE 5: NEW PLANT – RESOURCE CENTERS

Q. Please list the Resource Center projects included in this rate case.

A. This case includes the following projects:

- Central Resource Center Phase 2 (Central RC);
- Sunset Resource Center (Sunset RC);
- Miller Station Tenant Improvements (Miller Station);
- Sherwood Data Center; and
- Security upgrades.

Q. Please describe the Central Resource Center Phase 2 project.

A. NW Natural initiated planning for the Central RC in September 2017 and is completing construction in phases. In Phase 1, the Company completed site work and constructed outbuildings. Phase 2 construction began in February 2023 and includes a one-story office building with an attached warehouse. Upon completion of Phase 2, the Company plans to use this property to house workspace for emergency response crews. The Central RC will also contain storage for equipment, parts, and materials and will provide parking for Company vehicles.[20]

Q. Why is the Central RC Phase 2 Project necessary?

A. Phase 2 is necessary to better serve customers, improve facility safety for employees, and meet the Company's increasing emergency response needs. The Central RC will enable the Company to improve response times for

[20] NW Natural/600, Pipes/7.

emergencies in the central business district and in the central east side of Portland.[21]

Q. Has Phase 2 been placed in service and what is the estimated cost?

A. The Company expected Phase 2 in Service in December 2023 at an estimated cost of $9.2 million. The Central RC is allocated 100 percent to Oregon.

Q. Please summarize the upgrades NW Natural is making to the Sunset RC.

A. The Company is making seismic upgrades to the Sunset RC to address resiliency of critical equipment and known seismic vulnerabilities. The Company is also installing a new decanter system and truck scale to enable more efficient operations and ensure compliance with applicable requirements.

Q. When will the upgrades to the Sunset RC begin, and when will they be placed in service and what is the estimated cost?

A. Work on the Sunset RC upgrades is scheduled to begin in April 2024, and expected to be placed in service in October 2024. The Company estimates the cost to $4.1 million for all of the upgrades. The Sunset RC is allocated 100 percent to Oregon. Staff recommends a NWN officer attestation be required that the plant is in service prior to the rate effective date. Otherwise the plant should be removed from the rate base used to calculate revenue requirements.

Q. Please summarize the Miller Station Tenant Improvements.

[21] NW Natural/600, Pipes/7.

A. Miller Station is located at the Mist Facility in Mist, Oregon. The Company is expanding the existing office space into the warehouse to accommodate more employees and is making structural improvements to address seismic deficiencies.[22]

Q. When will the Miller Station Tenant Improvement Project be placed in service and what is the estimated cost of construction?

A. Construction of the improvements began in May 2023 and finished in mid-November of 2023. The company estimates the cost at $3.2 million or $2.8 million on an Oregon-allocated basis.

Q. Please summarize the upgrades the Company is making to the Sherwood Data Center.

A. To make the Sherwood Data Center more reliable and less vulnerable to failure, the Company is upgrading the electrical system, the HVAC system, and the fire alarm system, and adding a remote monitoring system and seismic upgrades. The Sherwood Data Center hosts 98 percent of the Company's applications, including critical business systems used for all building and asset management. It also houses the servers that receive and compile 90 percent of the data from the Company's Supervisory Control and Data Acquisition ("SCADA") system, which is used to monitor the gas distribution system.

Q. Why does the Sherwood Data Center need to be upgraded?

[22] NW Natural/600, Pipes/18.

A. An outage at the Sherwood Data Center would cause customer service issues and interrupt many aspects of the Company's business. The biggest risk is the potential for the Gas Control department to lose visibility to the SCADA system.

Q. When does the Company expect the upgrades to the Sherwood Data Center to be placed in service, and what is the estimated cost to complete?

A. The expected in-service date for the electrical, mechanical, and alarm system work was December 2023. The seismic work will be complete in the summer of 2024. The current projected cost for all the upgrades is $3.0 million, or $2.7 million on an Oregon-allocated basis.

Q. Please summarize Staff's recommendation for New Plant – Resource Centers.

A. Staff has not identified any projects it believes to be imprudently incurred. However, Staff does have concerns regarding the reliability of the Company's estimates, especially for projects projected to be placed into service near the rate effective date, and recommends attestations for those projects as further discussed in Issue 6 below. Staff's conclusions regarding prudence are not final and may change based on evidence presented by other parties.

Docket No: UG 490

Staff/600
Anderson/18

ISSUE 6: ATTESTATIONS AND PROPOSED PROJECT ADJUSTMENTS

Q. Regarding projects specifically discussed in the Company's testimony, what does Staff recommend?

A. Staff recommends officer attestations for the following projects for the reasons stated:

- North Coast Feeder Project

  Section A is expected to be placed in service in September 2024. The estimated cost to complete Section A is $8.2 million. This project is expected to be placed in service just prior to the rate effective date of October 31, 2024.

  Section B is expected to be placed in service at the end of the test year in December 2025. Since this phase of the project will not be "used and Useful" prior to the prior to the rate effective date, Staff recommends this phase be removed from revenue requirements and rate base for this general rate case.

- Tualatin-Sherwood Road Grading Project (the actual costs exceeding those already being recovered in rates)

  The Company completed this project in October 2022. Actual costs to place the project in service should be available to replace estimates.

- P30 Willis Creek HDD Install Project

  This project is in the planning stages and scheduled for construction Summer of 2024. There is a risk that the project will not be in service prior to the rate effective date, and the estimated cost is a rough order of

magnitude estimate. Staff recommends a NWN Officer attestation that the plant is in service prior to the rate effective date. Otherwise the plant should be removed from the rate base used to calculate revenue requirements.

- SE Gate Station Rebuild Project

  The project is expected to be placed in service in October of 2024, just prior to the rate effective date. There is a risk that the project will not be in service prior to the rate effective date, and the estimated cost is a rough order of magnitude estimate. Staff recommends a NWN Officer attestation that the plant is in service prior to the rate effective date. Otherwise the plant should be removed from the rate base used to calculate revenue requirements.

Q. What is the net financial impact to Utility Plant in Service from Staff's recommendations?

A. Staff recommends adjusting the Utility Plant by a ($6.4 million) for Section B of the North Coast Feeder Project, which will not be used and useful prior to the rate effective date of October 31, 2024.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 490
WITNESS: LAUREL ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 601

Witness Qualifications Statement
Staff: Anderson

April 18, 2024

Docket No. UG 490

Staff/601
Anderson/1

WITNESS QUALIFICATIONS STATEMENT

NAME: Laurel Anderson, CPA

EMPLOYER: PUBLIC UTILITY COMMISSION OF OREGON

TITLE: Utility Analyst,
Telecommunications and Water Division

ADDRESS: 201 High Street SE, Suite 100
Salem, OR 97301

EDUCATION: Certified Public Accountant

Bachelor of Science, Business, Accounting
Montana College of Mineral Science and Technology

Bachelor of Science, Agriculture, Animal Science
Montana State University

EXPERIENCE: Oregon Public Utility Commission since May 2007
Budget Analyst – May 2007 to July 2013
Utility Analyst – August 2013 to Present

Oregon Department of Human Services
Budget Analyst-May 2005 to May 2007
Oregon Employment Department
Employment Tax Auditor—October 2003 to April 2005

LaCie, Limited
Senior Corporate Accountant
Oxford Molecular Group
Business Segment Accountant

Fifteen years of Public Accounting experience including income tax, small business accounting, and municipal auditing

CASE: UG 490
WITNESS: RUSS BEITZEL

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 700

REDACTED
OPENING TESTIMONY
INSURANCE AND D&O
INSURANCE

April 18, 2024

Docket No: UG 490

Staff/700
Beitzel/1

Q. Please state your name, occupation, and business address.

A. My name is Russ Beitzel. I am Program Manager of the Rates and Telecommunications Section of the Rates, Safety and Utility Performance Program of the Public Utility Commission of Oregon (Commission or OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/701.

Q. What is the purpose of your testimony?

A. I present Staff's analysis in the general category of Insurance and Directors and Officers Insurance (D&O).

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared the following supporting exhibits beyond my witness qualifications:

- Exhibit Staff/702 NWN Responses to Staff Data Requests.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Insurance (Non-Medical) and Risk (Non-Medical) 2
Figure 1: OR Allocated Totals for Insurance and Risk Premiums 3
Issue 2. Directors and Officers Insurance 5
Summary 7

Docket No: UG 490

Staff/700
Beitzel/2

ISSUE 1. INSURANCE (NON-MEDICAL) AND RISK (NON-MEDICAL)

Q. Does the Commission have a standard means of determining how insurance expenses are treated?

A. Yes. During a rate case, Staff will examine a company's current premiums and remove any costs that are attributed to non-operating and non-regulated operations. Staff reviewed the Company-provided insurance premium documents, noting that these are purchased on the free-market either directly or through a third party tasked with finding the option that meets the Company's requirements.[1]

Q. Please describe how the Company allocates insurance premiums.

A. The Company provided a description of its allocation method in Testimony.

> …these expenses were allocated using the Company's insurance allocation model. This allocation model is designed in compliance with the Company's CAM. Pursuant to the Company's CAM, individual premiums are allocated to entities consistent with the nature of the insurance policy. For example, workers' compensation policies are allocated based on payroll, and property insurance is allocated based on total assets. The Company uses four allocation factors to allocate insurance premiums to non-utility operations and affiliates: revenues, assets, payroll, and number of directors and officers.[2]

Q. Please explain what types of insurance were reviewed.

A. Staff reviewed documents related to insurance for property, liability, terrorism, workers' compensation, and other risk management. Please see Confidential Figure 1 for a list of these various types of insurances and a chart comparing

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1 See Staff/702 Company response to Staff SDR 69 and Confidential response to Staff SDR 69 Attachment 1.

2 See NW Natural / 1400, Davilla / 13.

premiums from Base Year to Test Year.

FIGURE 1: OR ALLOCATED TOTALS FOR INSURANCE AND RISK PREMIUMS

[BEGIN CONFIDENTIAL]

[END CONFIDENTIAL]

Q. Is expense for insurance increasing?

A. The Company's forecasted Test Year expense for insurance exceeds the Base Year actuals by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** This increase is similar to increases noted in other recent energy rate cases.[3]

Q. Please summarize the Company's proposed Test Year expense for FERC 924 (Property Insurance).

[3] See UE 416 Staff/900, Beitzel/6-7 and UE 426 Staff/500, Beitzel/6 Table 1.

A. For the Test Year, the Oregon-allocated total for FERC Account 924 (Property Insurance) is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** increase from the Base Year (Highlighted in Figure 1 below).[4]

Q. Did Staff investigate the reason for the increase?

A. Yes. Staff reviewed the Company's response to Standard Data Request (SDR) Nos. 058 and 067-074 and DRs 224-225, including the confidential responses. In addition, Staff reviewed the Company's testimony on non-medical insurance in NW Natural/1400, Davilla/13.

Q. Is Staff proposing an adjustment involving any of these types of insurances?

A. No. In reviewing the premiums paid for each different type of insurance, Staff concluded the Company's decision to carry these types of insurance coverage is prudent and that the insurance premiums appear reasonable, despite the steady increases in cost. Because of the competitive nature of the insurance industry, it is Staff's position that premiums paid to protect the utility, and ultimately customers, from high dollar casualty losses represents a prudent business decision and that no adjustment is necessary.

[4] Staff/702, NW Natural amended response to Staff DR 224 - Confidential Attachment 1.

Docket No: UG 490

Staff/700
Beitzel/5

ISSUE 2. DIRECTORS AND OFFICERS INSURANCE

Q. What is D&O Insurance?

A. Directors and Officers insurance is liability insurance payable to the Directors and Officers of a company, or to the organization itself, as reimbursement for losses or advancement of defense costs in the event an insured suffers such a loss as a result of a legal action brought for alleged wrongful acts in their capacity as directors and officers. Such coverage can extend to defense costs arising out of criminal and regulatory investigations and trials as well. Intentional illegal acts, however, are typically not covered under D&O policies.

Q. Please explain the standard adjustment to D&O Insurance expense as it relates to NWN's request.

A. Staff has routinely recommend removal of 50 percent of Excess D&O liability insurance as a shareholder cost.[5] This methodology has been followed by Staff in previous dockets in both electric and natural gas utility general rate cases and approved by the Commission.[6] This adjustment is shown in Staff Exhibit 703.

Q. Please explain the rationale for this standard adjustment procedure.

A. D&O insurance protects senior management in the event that they are sued, whether by customers, shareholders, or others in conjunction with the performance of their duties. Customers, who have no say in electing or appointing a Utilities Directors or Officers, should not be held financially

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5 *In re* Portland *General Electric Company*, OPUC Docket No. UE 197, Order No. 09-020 at 19-20 (Jan. 22, 2009).

6 *Ibid*.

responsible for providing 100 percent of the insurance coverage against business decisions or improprieties by management which results in lawsuits. Additionally, a large number of claims are brought by shareholders; customers should not have to pay the full costs of total D&O insurance. The excess insurance should be considered a joint shareholder/customer cost.

Q. Does the Company include the cost of D&O Insurance premiums in its Test Year expense?

A. Yes. As stated in NWN Confidential Response to DR 224, the Oregon Test Year amount for D&O Insurance is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Oregon allocated (Highlighted in Figure 1 above).[7]

Q. What is Staff's proposed adjustment?

A. Staff proposes to adjust D&O Insurance by a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

[7] Staff/702, NW Natural amended response to Staff DR 224 - Confidential Attachment 1.

Docket No: UG 490

Staff/700
Beitzel/7

SUMMARY

Q. Please summarize your recommendations, identifying any adjustments you propose.

A. Related to the Insurance accounts, Staff proposes no adjustment at this time. Related to D&O Insurance expense, Staff proposes a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

As noted earlier in my testimony, my recommendations may change based on further review and as informed by the testimonies offered by other parties.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 490
WITNESS: RUSS BEITZEL

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 701

WITNESS QUALIFICATION STATEMENT

April 18, 2024

Docket No. UG 490

Staff/701
Beitzel/1

WITNESS QUALIFICATIONS STATEMENT

NAME: Russell (Russ) Beitzel

EMPLOYER: Public Utility Commission of Oregon

TITLE: Program Manager
Rates and Telecommunications Section

ADDRESS: 201 High Street SE, Suite 100
Salem, OR. 97301

EDUCATION: Bachelor of Science in Accounting, Otterbein University

EXPERIENCE:

I have been employed with the Public Utility Commission of Oregon since 2018. I am currently the Program Manager of the Rates and Telecommunications Section of the Rates, Safety and Utility Performance Program. I have analyzed and addressed numerous issues including tariff changes, property sales, affiliated interest transactions, revenue requirement calculations, deferred tax calculations, rate spread, and rate design. I have also served as case manager on multiple water rate cases, and have provided testimony in UW 185, UW 182, UW 175, UW 177, UE 374, UG 388, UE 416, and UE 426.

Additionally, I worked at Ashland, Inc. for twenty years as a manufacturing and corporate accountant and business analyst for a business unit with approximately one billion dollars in global annual sales. My accountant duties included product cost analysis, general ledger account analysis, SOX compliance, and internal and external audit compliance. My analyst duties included budgeting, forecasting, financial statement analysis, acquisition tracking, and division financial support for a global business unit.

CASE: UG 490
WITNESS: Russ Beitzel

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 702

NWN RESPONSES STAFF'S DATA REQUESTS

April 18, 2024

Staff/702
Docket No: UG 490 Beitzel/1

NW Natural®

Rates & Regulatory Affairs
UG 490
2024 Oregon General Rate Revision
Data Request Response

Request No.: UG 490 SDR 69

When were property insurance, liability insurance, workers' compensation insurance, and other insurance policies last updated? What is the termination date of these policies? Please provide "term" sheets that cite the premium costs for all current insurance premiums.

Response:

The policies last renewed on [Start Confidential] [redacted] [End] Confidential] for a term of one year expiring on [Start Confidential] [redacted] [End Confidential].

See Confidential UG 490 SDR 69 Attachment 1 for the "term" sheets citing the premium costs for all current insurance policies is attached.

Confidential information is subject to protection under OAR 860-001-0070 or Commission's Protective Order.

Docket No: UG 490

Staff/702
Betizel/2

CASE: UG 490
WITNESS: Itayi Chipanera

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 800

REDACTED
OPENING TESTIMONY

Escalations, Cash Working Capital, Regulatory Fees, Income Taxes, Leasehold Improvements

April 18, 2024

Docket No: UG 490 Staff/800
Chipanera/1

Q. Please state your name, occupation, and business address.

A. My name is Itayi Chipanera. I am a Senior Financial Analyst employed in the Accounting and Finance Section of the Rates, Safety and Utility Performance Program (RSUP) of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/801.

Q. What is the purpose of your testimony?

A. My opening testimony discusses Staff's analysis and position on the following issues:

- Escalation of Test Year expenses.
- Test Year cash working capital included in rate base.
- Test Year expenses for Regulatory Fees.
- Test Year expenses for Income Taxes.
- Test Year leasehold improvements included in rate base.

Q. Did you prepare any exhibits for this docket?

A. No.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Escalations 3
Issue 2. Cash working capital 6
Issue 3. Regulatory fees 12
Issue 4. Income taxes 14
Issue 5. Leasehold improvements 17
Other topics reviewed 19
Summary 20

Docket No: UG 490

Staff/800
Chipanera/2

Q. Could there be changes or updates to Staff's position and recommendations?

A. Yes. My testimony represents issues identified to date. My recommendations and issues may change when informed by new data and after reviewing testimony and analysis by other parties.

Docket No: UG 490 Staff/800
Chipanera/3

ISSUE 1. ESCALATIONS

Q. Please provide a summary of the Commission's historical treatment of expense escalations.

A. It is Staff policy to use the Consumer Price Index – All Urban Consumers for the U.S. (CPI, Urban U.S.) as published by the State of Oregon Office of Economic Analysis (OEA) for year over year escalation. The All-Urban CPI measures price changes in a fixed market basket of goods and services in categories, generally including housing, apparel, transportation, medical care, recreation, education, and others to urban consumers.

Q. Why is it necessary to evaluate the escalation factors applied by the Company?

A. The Company's system Test Year (2025) non-payroll operating, and maintenance expenses were filed as $133.4 million compared to $112.4 million in the Base Year (2023), an increase of $21 million.[1] The Company adjusted for some non-payroll O&M items directly without the use of a CPI, therefore the total increase in non-payroll O&M is not completely attributable to CPI escalation. The Company's application of escalation factors, however, is a very important aspect of its Test Year requested non-payroll O&M expenses and it is necessary for Staff to carefully evaluate the source of the escalation factors and how they are applied.

Q. How did the Company apply escalation factors in the filing?

A. According to the Company:

[1] UG 490 - Exh. 1400 - OM Model Workpaper.

> The Company escalated general non-payroll costs using year-over-year rates of change in the forecast of the West Region Urban CPI as reported in the September 2023 Oregon Economic and Revenue Forecast, published by the OEA. These escalation factors were applied on January 1, 2024, and January 1, 2025. The Company also identified several items where the growth projection was greater or lesser than using CPI and adjusted these items with their specific increase or decrease.[2]

Q. What is the Company's rationale for using the Western Region CPI instead of the All-Urban CPI?

A. The Company testifies, "NW Natural specifically selected the Western Region Urban CPI because a regional CPI provides better measure of aggregate changes experienced by the Company than the national CPI."[3] The Company says it sources its services and materials from within Oregon and Washington, therefore the regional CPI is more reflective of the price changes that the Company faces.

Q. Is using the West Region CPI reasonable considering the Company's cost escalation methodology?

A. No. The Company's claim the West Region CPI is more representative index is belied by their substitution of their own escalation rate for various cost categories. Staff does not disagree that it may be impossible to find an index that perfectly matches the inflation experienced by a utility in each cost category. However, Staff has consistently found the All-Urban CPI is a reliable and appropriate source for escalation and believes consistently using this

[2] NWN Natural/1400, Davilla/8, lines 13 to 19.
[3] NWN Natural/1400, Davilla/9, lines 3 to 5.

methodology eliminates "forum shopping" for the most favorable inflation escalator on a case-by-case basis.

Q. Have inflation forecasts changed since the September 2023 OEA report relied upon by the Company in its initial filing?

A. Yes. The most recent OEA publication was the March 2024 report, released on February 7, 2024.[4] The March report shows the 2024 and 2025 expected changes in the Western Region CPI index as 2.7 percent and 2.1 percent, respectively, and the change in All-Urban CPI index is expected to be 2.7 percent for 2024 and 2.0 percent for 2025.

Q. What is Staff's recommendation regarding the use of the Western Region CPI?

A. Although the expected changes in the Western Region CPI and All-Urban CPI index in the March publication are identical for 2024 and differ by 0.1 percent for 2025, Staff maintains its long-standing policy of relying on the All-Urban CPI. Staff recommends adjusting the Company's escalation factors to the All-Urban CPI factors as published in the March 2024 OEA report.

Q. Are you recommending any adjustments based on Staff's CPI recommendation?

A. No. Different parts of the Company's filing have been assigned to various Staff and they will apply Staff's recommended escalation factors in their individual reviews.

[4] Oregon Economic and Revenue Forecast, March 2024, Release Date: February 7th, 2024.

Docket No: UG 490 Staff/800
Chipanera/6

ISSUE 2. CASH WORKING CAPITAL

Q. What is cash working capital?

A. Cash working capital is the amount of investor supplied capital required by a utility to fund its day-to-day operations to provide service to customers prior to receipt of payment from customers. Cash working capital is included as part of the utility's rate base.

Q. Please provide a summary of the Commission's historical treatment of cash working capital.

A. The Commission has generally required a utility's request for cash working capital to be supported by a current lead/lag study.

Q. Did the Company support its cash working capital request with a lead/lag study?

A. Yes.

Q. How is cash working capital calculated?

A. Cash working capital is calculated by multiplying net lag days by the average daily cost of service. Average daily cost of service and net lag days can be broken into other components as shown in the series of equations below.

1. $Cash\ Working\ Capital\ = Daily\ Cost\ of\ Service * Net\ Lag\ Days$

$$Daily\ Cost\ of\ Service = \frac{Annual\ Cost\ of\ Service}{365}$$

$$Net\ Lag\ Days\ = Revenue\ Lag - Expense\ Lag$$

$$Revenue\ Lag = Service\ Lag + Billing\ Lag + Collection\ Lag$$

$$Service\ Lag = Meter\ Read\ Date - Mid\ Point\ of\ Customers\ \ Usage\ Period$$

$$Billing\ Lag = 0$$

$$Collection\ Lag = \frac{Average\ Monthly\ Receivables}{Average\ Daily\ Sales}$$

2. $Cash\ Working\ Capital = Daily\ Cost\ of\ Service * \{Service\ Lag + Billing\ Lag + Collection\ Lag - \ Expense\ Lag\}$

Q. How did Staff evaluate the Company's cash working capital calculation for reasonableness?

A. The breakdown of the cash working capital calculation into the series of equations shown above is useful for Staff to analyze the critical drivers of the requested cash working capital amount. Staff separately analyzed each of the components of the cash working capital calculation, particularly the revenue lag and expense lag.

Q. What is the revenue lag and how did the Company calculate its revenue lag?

A. The revenue lag represents the days between the receipt of services by customers and the eventual payment for those services. The revenue lag is the sum of the service lag, the billing lag, and the collection lag.

Q. How did the Company calculate its service lag?

A. The Company calculated its service lag as the "time from the midpoint of a customer's usage period to the meter read date. The Company bills all

customers on a monthly basis and, therefore, the average service lag equates to approximately half of a month or about 15.5 days."[5]

Q. What is Staff's view on the service lag calculated by the Company?

A. Staff believes the Company's service lag is overstated. The Company's method of calculating the service lag did not properly account for months that have an odd number of days and over counts the mid-point of months with odd days by half a day. Staff proposes a method that properly accounts for the half days that are part of a month with an odd number of days. Using Staff's proposed approach, Staff calculates a service lag of 15.2 days.

Last Day	Midpoint Date	Company Method	Staff Proposed Method
1/31/2022	1/16/2022	16	15.5
2/28/2022	2/14/2022	14	14.0
3/31/2022	3/16/2022	16	15.5
4/30/2022	4/15/2022	15	15.0
5/31/2022	5/16/2022	16	15.5
6/30/2022	6/15/2022	15	15.0
7/31/2022	7/16/2022	16	15.5
8/31/2022	8/16/2022	16	15.5
9/30/2022	9/15/2022	15	15.0
10/31/2022	10/16/2022	16	15.5
11/30/2022	11/15/2022	15	15.0
12/31/2022	12/16/2022	16	15.5
		15.5	15.2

Q. What is the impact of reducing the Company's service lag from 15.5 days to 15.2 days?

A. Using the Company's filed cash working capital workpaper,[6] Staff reduced the service lag from 15.5 days to 15.2 days and produced an Oregon allocated

[5] NW Natural/1700, Walker/33, line 19.
[6] UG 490 - Exh. 1713 - WP3 - Cash Working Capital – CONFIDENTIAL.

cash working capital amount that is $292.9 thousand lower than the Company's calculation.

Q. Does Staff have any concerns with how the Company estimated the collection lag and the billing lag?

A. No. The collection lag, which is the interval from the invoice date to the date until the customer pays for service, is calculated by dividing average monthly sales by average daily sales. The billing lag is the interval from when the meter is read and when the company processes an invoice in its billing system. The Company says it bills its customers on the same day that it reads meters, therefore the billing lag is zero days.

Q. How did the Company calculate its expense lag?

A. The Company studied expenses for materials received and services rendered separately. The expense lag for materials received was calculated by comparing the invoice date with the payment date. The expense lag for services rendered was calculated by comparing the midpoint of the service period with the payment date. The Company studied the following expense categories:

1. Purchased Gas,
2. Labor,
3. Payroll, Employee Benefits,
4. Prepaid Insurance,
5. Prepaid Information Technology,
6. Regulatory Fees,

7. Municipal Franchise Fees,
8. Other O&M, and
9. Payroll Taxes and Other Taxes (Federal/State, Corporate Activities Tax and Property Taxes).

Q. Does Staff have any concerns with how the Company calculated expense lead/lag days for any of the expense categories?

A. Yes. Staff is concerned that some of the data used to calculate the information technology expense lead days is not representative of the routine contract that requires the company to have a cash cushion provision in the Test Year. The Company said it conducted its analysis using all contracts that were active in calendar year 2022 and it does not forecast prepaid information technology amounts or contracts.[7] Staff identified three information technology contracts the Company has already paid in full even though they extend through the Test Period. Staff proposes to exclude these three contracts from the Test Year cash working capital calculation.

Q. Which three contracts is Staff proposing to exclude from the expense lag calculation?

A. Staff is proposing to remove the three contracts listed in the confidential table below.

[7] NW Natural response to DR 433.

Docket No: UG 490

Staff/800
Chipanera/11

[BEGIN CONFIDENTIAL]

[END CONFIDENTIAL]

Q. How does the exclusion of the informational technology contracts whose payment dates and prospective renewal dates fall outside the Test Year affect the Company's cash working capital calculation?

A. Excluding these contracts from the cash working capital calculation reduces the Company's information technology expense lead time from 216.04 days to 205.5 days. The change in the information technology lead time results in a reduction to the Company's cash working capital of $220.4 thousand.

Q. What is your total proposed adjustment to the Company's cash working capital?

A. Adjusting the Company's revenue service lag and the information technology expense lead time as proposed reduces the Company's cash working capital by $513.3 thousand.

Docket No: UG 490

Staff/800
Chipanera/12

ISSUE 3. REGULATORY FEES

Q. What is the Oregon regulatory commission fee in this docket?

A. The regulatory commission fee is composed of two fees, the Oregon Public Utility Commission fee (OPUC fee) and the Oregon Department of Energy, Energy Supplier Assessment (ODE ESA). The OPUC fee is a customer-funded fee whose purpose is to cover operating expenses of the Oregon Public Utility Commission. The Commission approves a rate used to collect OPUC fees and the rate is applied to a utility's revenues. The energy supplier assessment is similarly levied on energy suppliers operating in Oregon to fund the Oregon Department of Energy operations. Yearly energy supplier assessments are approved by the Oregon legislature and are capped at 0.375 percent of revenues.[8]

Q. How much is the Company requesting for OPUC fees in the 2024 Test Year and how does it compare to the 2022 Base Year?

A. The Company is requesting $4.024 million in regulatory fees for the Test Year compared to $4.006 million in the Base Year, an increase of 0.5 percent.

Q. What was the OPUC fee rate in effect at the time of the Company's filing?

A. At the time of NW Natural's filing the OPUC fee rate in effect was 0.43 percent.[9]

Q. Did the Company use the OPUC fee rate in effect at the time of its filing to calculate its Test Year OPUC fees?

---

[8] How We Are Funded, Oregon Department of Energy, published October 2023.
[9] *In the Matter of The Imposition of Annual Regulatory Fees upon Public Utilities Operating within the State of Oregon*, Docket No. UM 1012, Order No. 23-057.

A. Yes.

Q. Has the OPUC fee rate changed since the Company's filing?

A. Yes. The Commission approved a new rate of 0.45 percent in Order No. 24-054 entered on February 22, 2024.[10]

Q. What is Staff's proposed adjustment to OPUC fees?

A. Staff proposes to adjust the OPUC fees by applying the current effective rate of 0.45 percent. Applying the new rate produces a Test Year OPUC fees amount of $4.2 million, an increase of $187.2 thousand.

Q. How did the Company estimate the Test Year amount for the Department of Energy, Energy Supplier Assessment?

A. The Company used a three-year ODE ESA average rate and applied that rate to Test Year retail sales.

Q. What is Staff's view on how the Company estimated the ODE ESA?

A. Staff agrees with the Company's three-year average rate approach to determine the Test Year ODE ESA amount.

[10] *In the Matter of The Imposition of Annual Regulatory Fees upon Public Utilities Operating within the State of Oregon*, Docket No. UM 1012, Order No. 24-054.

Docket No: UG 490 Staff/800
Chipanera/14

ISSUE 4. INCOME TAXES

Q. Please summarize the Company's filing related to income taxes.

A. The Company presents Test Year state income taxes of $16.9 million and federal income taxes of $26.5 million on exhibit NW Natural/1705.[11] The calculated federal income taxes include $3.2 million of federal tax credits.[12]

Q. What are the requirements of Oregon law regarding the inclusion of income taxes in utility rates?

A. Income taxes in utility rates are subject to the requirements of ORS 757.269:

> **757.269 Setting of rates based upon income taxes paid by utility; limitation on use of tax information; rules**.
> (1) When establishing schedules and rates under ORS 757.210 for an electricity or natural gas utility, the Public Utility Commission shall act to balance the interests of the customers of the utility and the utility's investors by setting fair, just and reasonable rates that include amounts for income taxes. Subject to subsections (2) and (3) of this section, amounts for income taxes included in rates are fair, just and reasonable if the rates include current and deferred income taxes and other related tax items that are based on estimated revenues derived from the regulated operations of the utility.
>
> (2) During ratemaking proceedings conducted pursuant to ORS 757.210, the Public Utility Commission must ensure that the income taxes included in the electricity or natural gas utility's rates:
>
> (a) Include all expected current and deferred tax balances and tax credits made in providing regulated utility service to the utility's customers in this state;
> (b) Include only the current provision for deferred income taxes, accumulated deferred income taxes and other tax related items that are based on revenues, expenses and the rate base included in rates and on the same basis as included in rates;
> (c) Reflect all known changes to tax and accounting laws or policy that would affect the calculated taxes;
> (d) Are reduced by tax benefits generated by expenditures made in providing regulated utility service to the utility's customers in this state, regardless of whether the taxes are paid by the utility or an affiliated group;

[11] NW Natural/1705, Walker/1.
[12] NW Natural/1710, Walker/1.

(e) Contain all adjustments necessary in order to ensure compliance with the normalization requirements of federal tax law; and
(f) Reflect other considerations the commission deems relevant to protect the public interest.

(3) During a ratemaking proceeding conducted under ORS 757.210 for an electricity or natural gas utility that pays taxes as part of an affiliated group, the Public Utility Commission may adjust the utility's estimated income tax expense based upon:

(a) Whether the utility's affiliated group has a history of paying federal or state income taxes that are less than the federal or state income taxes the utility would pay to units of government if it were an Oregon-only regulated utility operation;
(b) Whether the corporate structure under which the utility is held affects the taxes paid by the affiliated group; or
(c) Any other considerations the commission deems relevant to protect the public interest.

(4)(a) Because tax information of unregulated nonutility business in an electricity or natural gas utility's affiliated group is commercially sensitive, and public disclosure of such information could provide a commercial advantage to other businesses, the Public Utility Commission may not use the tax information obtained under this section for any purpose other than those described in this section, in ORS 757.511 and as necessary for the implementation and administration of this section and ORS 757.511.

(b) The commission shall adopt rules to implement paragraph (a) of this subsection that:

(A) Identify all documents and tax information that an electricity or natural gas utility must file in its initial filing in a proceeding to change rates that include amounts for income taxes, recognizing that any party may object to providing such documents on the grounds that they are not relevant; and
(B) Determine the procedures under which intervenors in such proceedings may obtain and use documents and tax information to fully participate in the proceeding.

(5) As used in this section, "affiliated group" means a group of corporations of which the public utility is a member and that files a consolidated federal income tax return. [2011 c.137 §1]

Q. Please summarize Staff's review of income taxes in this case.

A. Staff initially reviewed tax information in the Company's filing and reviewed the Company's responses to standard data requests. Staff's examination and

discovery included confirming the federal and state tax rates, apportionment calculations, calculation of current and deferred income tax expense, application of federal and state tax credits, and the amortization of excess deferred income taxes (EDIT) resulting from the 2017 Tax Act.

Q. Please summarize the Company's filing regarding accumulated deferred income taxes.

A. The Company determined Test Year deferred income tax included in rate base by using the December 31, 2022, deferred income taxes and forecasting forward for incremental amounts. The Company said it considered new capital expenditures as well as previous basis amounts in generating book-tax differences and consequent tax.[13] The amount of Oregon allocated deferred income taxes included in Test Year rate base is $447.9 million compared to $438.1 million in the Base Year.

Q. Is Staff proposing adjustments to income tax expense other than those necessary to finalize the Company's revenue requirement?

A. Other than the EDIT adjustment proposed by Staff witness Luz Mondragon in Staff /200, Staff is proposing no further adjustments to the Company's income tax calculation.

[13] NW Natural/1700, Walker/31.

Docket No: UG 490 Staff/800
Chipanera/17

ISSUE 5. LEASEHOLD IMPROVEMENTS

Q. What is NW Natural's proposal regarding leasehold improvements in the filing?

A. The Company proposes to include $18.6 million in leasehold improvements in rate base. The filed leasehold improvements balances are primarily from the Company's headquarters building located at 250 Taylor, in downtown Portland.[14]

Q. What is the Commission's historical treatment of leasehold improvements?

A. The Company initially sought cost recovery associated with leasehold improvements at 250 Taylor in its 2020 GRC, UG 388. The Commission approved a Stipulation resolving all issues in that case that allowed the Company to include leasehold improvements balances as part of its rate base except for specific costs related to a fireplace, water feature, wine cooler, and board room table, which were excluded.[15]

Q. Is the Company's treatment of leasehold improvements consistent with UG 388?

A. Yes. The Company treated leasehold improvements in the same manner in UG 490 as it did in UG 388, including removing the costs that were identified to be excluded from rate base.

Q. Is Staff proposing any adjustments to leasehold improvements?

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[14] NW Natural/1700, Walker/17.
[15] *In the Matter of NW Natural Gas Company, Request for a General Rate Revision,* UG 388, Order No. 20-364 (October 24, 2020).

Docket No: UG 490

Staff/800
Chipanera/18

A. No.

Docket No: UG 490

Staff/800
Chipanera/19

OTHER TOPICS REVIEWED

Q. Please summarize Staff's review of any other topics that were not explicitly discussed in this testimony.

A. Staff reviewed the Company's Test Year amounts for franchise fees and property taxes. In both cases, the Company relied on a historical three-year average rate applied to a suitable base to estimate the Test Year amounts. The suitable tax base for property taxes is assessed property values and the suitable tax base for franchise fees is the utility's revenue. Staff has relied on the three-year average rate approach in prior rate cases as a reasonable way to estimate franchise and property taxes.

Q. Does Staff agree with how the Company handled franchise fees and property taxes in the filing?

A. Yes.

Docket No: UG 490

Staff/800
Chipanera/20

SUMMARY

Q. Please summarize Staff's proposed adjustments in this testimony.

A. Staff is proposing to reduce the Company's Test Year cash working capital by $513.3 thousand and increase the Company's OPUC fees by $187.2 thousand.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 490
WITNESS: ITAYI CHIPANERA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 801

Witness Qualifications Statement

April 18, 2024

Docket No. UG 490

Staff/801
Chipanera/1

WITNESS QUALIFICATIONS STATEMENT

NAME: Itayi Chipanera

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Financial Analyst
Accounting and Finance Section

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION: B.S., Economics
Idaho State University

M.S., Mathematics
University of Nevada – Reno

M.S., Accounting
Indiana University – Bloomington

EXPERIENCE: I have been employed by the OPUC in the Safety, Rates and Utility Performance Program since April of 2023. Prior to my employment with the OPUC I was employed in various finance roles in the insurance and banking industries including Advantis Credit Union where I was employed as a Senior Risk and Financial Analyst; City of Salem, Oregon, where I was a Finance Management Analyst; and SAIF Corporation where I was an Actuarial Research Analyst. I have worked as a revenue requirement summary witness on the following cases PGE UE 416, AVA UG 461, and IPC UE 426.

CASE: UG 490
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 900

REDACTED
Opening Testimony

April 18, 2024

Docket No: UG 490

Staff/900
Dlouhy/1

Q. Please state your name, occupation, and business address.

A. My name is Curtis Dlouhy. I am a Senior Economic and Policy Analyst employed in the Utility Strategy and Integration Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/901.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the Company's revised decarbonization asks following the invalidation of the Climate Protection Program (CPP), proposed changes to the renewable natural gas automatic adjustment clause, updates to the Company's residential line extension allowance, and meter modernization program.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared the following exhibits:

- Exhibit 901: Witness Qualifications Statement
- Exhibit 902: Non-Confidential Responses to Data Requests used in Support of Opening Testimony
- Exhibit 903: Other Documents in Support of Opening Testimony
- Exhibit 904: Staff's Line Extension Allowance Model
- Exhibit 905: Excerpt from Staff's Final Comments in LC 79
- Exhibit 906: Past RG 41 Filings

- Exhibit 907: Confidential Responses to Data Requests used in Support of Opening Testimony

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Climate Protection Program 3
Issue 2. Renewable Natural Gas Automatic Adjustment Clause 12
Issue 3. Residential Line Extension Allowance 27
Issue 4. Meter Modernization Program 47

Docket No: UG 490

Staff/900
Dlouhy/3

ISSUE 1. CLIMATE PROTECTION PROGRAM

Q. What is the purpose of this section of your testimony?

A. I summarize the regulatory environment surrounding the Climate Protection Program (CPP) in Oregon and provide recommendations on the Company's requested five Full-Time Equivalents (FTEs) related to CPP compliance.

Q. What was the CPP and how did it relate to Executive Order 20-04?

A. Executive Order 20-04 (EO 20-04) was issued by former Governor Kate Brown on March 10, 2020. EO 20-04 directs various state agencies to take action to reduce and regulate greenhouse gas (GHG) emissions in response to climate change. In particular, EO 20-04 sets a target of reducing Oregon GHG emissions to at least 45 percent below the 1990 emissions level by 2030 and at least 80 percent below the 1990 emissions levels by 2050.[1] To meet these goals, Oregon Environmental Quality Commission (OEQC) and Oregon Department of Environmental Quality (ODEQ) were directed to cap and reduce emissions from large stationary sources of GHG emissions, transportation fuels, and all other liquid and gaseous fuels.[2] Among other things, the PUC was directed to prioritize activities that advance decarbonization and determine whether utility portfolios and customer programs reduce risks and costs to utility customers by making rapid progress towards reducing GHG emissions consistent with Oregon's goals.[3]

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1 EO 20-04, page 5.
2 EO 20-04, pages 6-7.
3 EO 20-04, pages 7-8.

The CPP was a program implemented by OEQC and ODEQ to implement EO 20-04. The program subjected Oregon natural gas utilities to an annual cap on regulated GHG emissions. This cap would have declined annually until it was equal to a 50 percent reduction of the average annual 2017-2019 emissions in 2035 and a 90 percent reduction of the average annual 2017-2019 emissions in 2050. ODEQ planned to freely distribute the compliance instruments up to the amount of the annual cap, and entities could also choose to invest in bankable Community Climate Investments (CCIs) as an alternative way to meet compliance obligations. In effect, the CCIs would have helped fund decarbonization projects.

Q. Why was the CPP declared invalid and how does DEQ plan to respond?

A. As the Company describes in Exhibit 2000, the rules implementing the CPP were declared invalid on procedural grounds.[4] On January 22, 2024, the OEQC and ODEQ stated that they do not intend to appeal the court's decision but will instead begin a new rulemaking process in early 2024. The proposed rulemaking is active with engagement beginning on April 4, 2024, and is expected to conclude in June 2024. The stated goal is to, "[r]eestablish a climate program with comparable scope and emissions reduction ambitions as the previously adopted Climate Protection Program."[5] The Company expects that this process may take around 12 months to complete.[6]

4 NWN/2000, Kravitz – Therrien/3.
5 See the Climate Protection Plan Advisory Committee Rulemaking Schedule, here.
6 NWN/2000, Kravitz – Therrien/3-4.

Q. What was Northwest Natural's role in the decision by the Oregon Court of Appeals to declare the CPP invalid?

A. Northwest Natural, along with Oregon's two other investor-owned natural gas companies and several other entities, were the petitioners in the case in which the Court of Appeals ruled the rules establishing the CPP were invalid. Petitioners challenged the rules on both procedural and substantive grounds, but the Court of Appeals' opinion only addressed one procedural challenge, finding it was dispositive and there was no need to review the other challenges.[7]

Q. Why do you believe that this is relevant to your testimony?

A. While EO 20-04 is still effective, the future of the CPP is ambiguous in light of the likelihood that the petitioners in the 2023 Court of Appeals challenge will likely re-new the challenges to any EQC rules re-establishing the CPP. NW Natural and other entities have succeeded in delaying implementation of the CPP and it is likely these entities will continue to their challenges to the program if new rules are implemented. Given the uncertainty surrounding the future of the CPP, Staff is concerned that it is premature for NWN to receive rate recovery for costs to implement the CPP.

On the other hand, to properly plan around the regulatory uncertainty while still making progress towards decarbonization, Staff believes that taking "no regrets" actions that have system benefits whether or not the CPP is active

[7] *Northwest Natural Gas Company, et al., vs. Environmental Quality Commission*, 329 Or. App. 648 (2023).

is the most prudent path forward. These actions may include taking actions to limit system growth for the time being, pursuing energy efficiency actions, or investing in non-pipe alternatives.

Q. How does Staff believe these conflicting concerns be addressed?

A. Staff recognizes the need for a fine balance between allowing the Company to meet Oregon's decarbonization goals, advocating for policies in furtherance of said goals, while also taking into account the setbacks that have already occurred in implementing the CPP and the potential for future setbacks.

Q. Did the Company request that any costs related to the CPP be recovered?

A. Yes. In its opening testimony, the Company requests to recover costs associated with five additional FTEs focused on decarbonization and CPP compliance.[8] In its supplemental testimony, the Company reaffirmed its request to recover costs associated with these positions.[9]

Q. What are the job descriptions for these five positions and why does the Company believe that these positions should still be recovered following the invalidation of the CPP?

A. The Company requests that the following positions be recovered in this general rate case:

- Decarbonization Services Analyst: This position will research new and emerging technologies and develop business cases for decarbonization

[8] NW Natural/1500, Kravitz – Chittum/20.
[9] NW Natural/2000, Kravitz – Therrien/6.

services. The Company states that this is a necessary position because even though the CPP has been invalidated, the Company must take steps to decarbonize and DEQ is opening a new rulemaking related to EO 20-04.[10]

- Decarbonization Services Operations Support: This position exists largely to support the Decarbonization Service Analyst. The Company's reasons to continue asking recovery for this position are similar to the Decarbonization Service Analyst.
- Decarbonization Portfolio Manager: This position was intended to manage the Company's decarbonization portfolio prior to the CPP's invalidation.[11] The Company states that they envisioned this role managing CPP compliance workstreams pre-CPP invalidation. Post invalidation, the Company states that they envision this role as engaging in the upcoming rulemaking process.[12]
- Decarbonization Compliance Rates Analyst: This role focuses on providing regulatory analytical support for the Company's decarbonization efforts. The Company states that this role can support its decarbonization efforts, such as RNG acquisition.[13]
- Peak Load Management Analyst: This position performs research, analysis, and other tasks related to Demand Side Management (DSM)

[10] NW Natural/2000, Kravitz – Therrian/6-7.
[11] NW Natural/2000, Kravitz – Therrian/8.
[12] Id.
[13] NW Natural/2000, Kravitz – Therrian/9.

programs. The Company notes that the Commission stated that it expects the Company take seriously the expectation that they mitigate growth where reasonable while trying to maintain reliable service.[14]

Q. Does Staff believe that the Company should be allowed to recover costs related to all these positions?

A. No. Staff believes that only one of these positions' costs should be recovered for the reasons discussed above.

Q. Which role does Staff believe warrants cost recovery even though the CPP has been declared invalid?

A. Staff supports the inclusion of costs related in revenue requirement to the Peak Load Management Analyst. This support is grounded in Staff's experience and belief that exploring methods to reduce load holds intrinsic value for both the Company and its ratepayers, irrespective of the validity of the CPP or any future decarbonization obligation the Company may have. To this note, Staff views pursuing non-pipes alternatives to be a clear "no regrets" path amid the current regulatory uncertainty.

Q. Please explain your conclusion rate recovery for four or the decarbonization FTEs is not warranted at this time.

A. NW Natural's decarbonization efforts are not new. NW Natural has been actively seeking and investing in RNG projects for many years and has had the regulatory team necessary to obtain rate recovery for RNG investments. NW Natural also participated in the original rulemaking proceeding for the CPP.

[14] NW Natural/2000, Kravitz – Chittum/10.

Absent a new compliance program with which to comply, Staff does not think addition of four incremental FTEs to manage decarbonization portfolios, explore emerging technologies, manage compliance workstreams, and participate in the EQC rulemaking are warranted.

Q. Why does Staff believe rate recovery for a Decarbonization Compliance Rates Analyst is not warranted?

A. According to the Company's testimony, the Decarbonization Compliance Rates Analyst's primary job is to provide analysis and prepare documents for regulatory proceedings related to decarbonization.[15] Absent the CPP or a successor program, the Company states that this role would still have duties related to developing its RNG resources and working on decarbonization projects related to a future Oregon GHG emissions law.[16] Staff does not envision there being significant analysis of the rate impacts of decarbonization absent the CPP or a successor program and would like to reiterate that the SB 98 targets are entirely voluntary.

Q. Why does Staff believe that the Decarbonization Portfolio Manager does not have sufficient duties to warrant an extra FTE?

A. The Company states that if this position were approved, the duties of managing CPP compliance workstreams and recommending compliance actions will not be part of the job's initial duties.[17] Absent this, the only duty the Company lists

15 NW Natural/2000, Kravitz – Therrien/9.
16 Id.
17 NW Natural/2000, Kravitz – Therrien/8.

for this position is to engage in the upcoming rulemaking process and the implementation of new Oregon GHG laws and regulations.[18]

Staff has concerns with funding a position solely dedicated to participating in a GHG emissions rulemaking process. Staff reiterates that the Company states that the *sole* duty for this position is to engage in a single rulemaking process. Staff remains unconvinced that an entire FTE needs to be devoted to engaging in a *single* rulemaking process that may take upwards of a year. While Staff does not disagree with the Company's claim that managing a decarbonization workstream may warrant a full FTE if the CPP or a similar program were in place, Staff finds no reason that funding this position at the moment is in customers' best interest and believes that these duties could be easily managed by existing Company employees.

Q. Why does Staff oppose the inclusion of the FTEs associated with the Decarbonization Services Analyst and the Decarbonization Services Operations Support in rates?

A. According to the Company's testimony, these positions will pursue decarbonization projects. The Company's testimony emphasizes that absent the CPP, these positions can pursue RNG-related projects related to SB 98 RNG acquisitions targets.[19]

Staff first notes that the RNG acquisition targets are voluntary rather than mandatory. Therefore, Staff is skeptical of the customer benefit of giving the

[18] Id.
[19] NW Natural/2000, Kravitz – Therrien/7.

Company more resources to pursue RNG projects. The Commission has echoed this skepticism in its previous orders related to RNG acquisition.[20]

In other dockets, Staff has expressed its belief that the Company's RNG acquisitions have failed to provide adequate risk modeling or customer protections.[21] Staff finds it to be imprudent to allow additional RNG administrative costs to be recovered by customers given Staff's concerns about RNG project selection and performance.

Staff agrees with the Company that the Company's decarbonization obligations still exist due to EO 20-04 and believes that the continued decarbonization work must be done absent the CPP. However, given the set back to implementation of the CPP, Staff believes it is premature to include in revenue requirement the costs of five incremental employees to implement the CPP.

Q. Please summarize Staff's overall recommendation regarding the five new FTEs related to decarbonization.

A. Staff recommends that the costs associated with four of the new FTEs be removed from revenue requirement for the reasons described above. The rate impact of this adjustment is included in the overall labor cost adjustment in the testimony of Staff Witness Stephanie Yamada in Staff Exhibit 2000.

[20] Order No. 23-281, page 12.
[21] See UG 462, Staff/200, Drennan/9.

Docket No: UG 490

Staff/900
Dlouhy/12

ISSUE 2. RENEWABLE NATURAL GAS AUTOMATIC ADJUSTMENT CLAUSE

Q. What is the purpose of this section of your testimony?

A. The purpose of this section of testimony is to summarize and respond to the Company's proposed changes to its Renewable Natural Gas (RNG) Automatic Adjustment Clause (AAC) mechanism, which is contained in Schedule 198.

Q. Please provide a brief history about how the RNG AAC in Schedule 198 came to be.

A. The RNG AAC was approved in UG 435 in Order No. 22-388. In this docket, NW Natural Proposed an AAC, Schedule 198, to recover its costs for the Lexington RNG project and future RNG projects. This would have an annual rate effective date of November 1. The Company also proposed to allow the inclusion of a deferral to track any startup O&M costs incurred prior to the RNG project being put into service and any revenue requirement between the project's in-service date and the rate effective date.[22]

Unanimous agreement on the Company's proposal was not reached, with some parties outright opposing the addition of Schedule 198 and other parties proposing modifications. Ultimately, the Commission adopted a version of Schedule 198 that incorporates proposed changes from CUB and Staff. The adopted version allows for the RNG AAC to have an annual rate effective date of November 1 and a deferral between forecasted and actual RNG costs subject to an earnings test at 50 basis points below authorized ROE but does

[22] *In the Matter of Northwest Natural Gas Company, dba NW Natural,* UG 435, Order No. 22-388, page 64 (October 24, 2022).

not allow for a deferral between the in-service date and the rate effective date.[23]

In making this decision the Commission noted that it had many concerns with the mechanism that the Company proposed. In Order No. 22-388, the Commission highlights that SB 98 contains *voluntary* RNG targets, whereas the CPP imposes a comprehensive and mandatory GHG cap and reduce mandate, with targets achievable through various channels. The Commission expressed concern that an overly generous AAC may skew the Company's analysis of CPP compliance towards RNG projects that receive full risk-free cost recovery.[24] Staff has previously expressed concern that the Company's current RNG acquisition strategy appears to be skewed to these rate based RNG projects with high customer risk relative to a less risky RNG off-take agreement.[25] The Commission also expressed that it is common practice to not allow for a deferral between the in-service date and rate effective date and did not find reason to change this practice for RNG projects given the Commission's other concerns.[26]

Q. What changes is the Company's proposing to Schedule 198, RNG cost recovery, and its RNG acquisition strategy?

A. In its opening testimony, the Company proposed to make two main changes to its RNG cost recovery:

[23] Order No. 22-388, page 82.
[24] Order No. 22-388, page 81.
[25] See UG 462, Staff/200, Drennan/9.
[26] Order No. 22-388, page 83.

1. Permit deferrals between the in-service date of the RNG project and the rate effective date,[27] and
2. Set the earnings test for the RNG AAC at the Company's authorized ROE.[28]

In addition to these main changes, the Company proposes to develop RNG investment projects through the utility rather than through an affiliate, which was used for the Lexington and Dakota City projects.[29]

Q. Regarding the Company's first proposed Schedule 198 change, what reasons does the Company give to justify a deferral for RNG projects between the in-service and rate effective dates?

A. The Company states that the CPP is a mandatory program that requires the Company to make investments for compliance purposes. NW Natural makes the comparison to the Renewable Resource Automatic Adjustment Clauses (RAC) that allow electric utilities to recover costs of renewable electric resources through both an AAC and deferral because such investments are necessary for an electric utility to meet its renewable portfolio standard (RPS) obligations.[30] The Company draws a comparison between the CPP and RPS and believes it is consistent to allow them to defer the revenue requirement between the in-service date and rate effective date for RNG resources.

Q. Does Staff agree that the RAC is a fair comparison?

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[27] NW Natural/1500, Kravitz – Chittum/15.
[28] NW Natural/1500, Kravitz – Chittum/20.
[29] NW Natural/1500, Kravitz – Chittum/14.
[30] NW Natural/1500, Kravitz – Chittum/15.

A. Not entirely. Staff notes that RPS requires Oregon-regulated electric utilities to meet their obligation solely through generation of renewable energy whereas the CPP was more agnostic about how the Company can meet its emissions reduction targets. In theory, the Company could have met its entire GHG emissions reductions obligations by reducing its natural gas load to a non-zero level that brings its emissions below the CPP cap through strategic electrification, energy efficiency, non-pipes alternatives, or other means. While RNG is one tool that the Company could have used to meet this obligation, it was far from the only tool.

However, when it comes to RPS this was not possible. It is indeed true that an electric utility could offset some of their RPS obligations by pursuing load reducing strategies such as non-wires solutions, energy efficiency, or demand response. However, the RPS was structured as a percent of load program, meaning that an Oregon utility subject to the RPS would have some renewable energy obligations if it has *any* non-zero load. Therefore, an electric utility was forced to use some level of renewable electricity to meet its obligation in Oregon's RPS framework, whereas NW Natural would have had no obligation to use RNG to meet its CPP obligations.

Further, Staff notes that the regulatory environment surrounding renewable electricity when the RAC was approved is much different than the current challenges facing RNG. Whereas renewable electricity projects at the time the RAC was approved were widely commercially available and well

known, Staff notes that RNG is still expected to both be costly and risky—a point that the Commission noted in the Company's most recent IRP, LC 79.[31]

Q. Are there other reasons that Staff believes that comparing the Company's RNG AAC to the RAC is not a good reason to approve the Company's requested?

A. Yes. In UE 416 (PGE's 2023 GRC), Staff testified the use of the RAC should be investigated given the drastic change in policy landscape following the passage of HB 2021 to balance concerns of customer protections with resource acquisition.[32] Staff expressed concerns that the RAC—which was authorized as part of the RPS program— was being used to recover costs associated with HB 2021 that were not clearly needed for RPS compliance. While Staff did not necessarily say that this was detrimental to customers, Staff highlighted the need to balance renewable electricity acquisition with customer protection. If the Commission does believe that the RAC and the RNG AAC are suitable comparisons, Staff still believes that this need to balance acquisition with customer protection is extremely important. For reasons previously stated, Staff believes that the Company's current RNG AAC already benefits the Company at the expense of retail customers. Furthermore, Staff believes that the Company's proposed changes would only exacerbate the imbalance.

Q. Would Staff support this deferral if the CPP were in place?

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[31] *In the Matter of Northwest Natural Gas Company, dba NW Natural 2022 Integrated Resource Plan*, LC 79, Order No. 23-281, page 12 (August 2, 2023).

[32] See UE 416, Staff/1100, Dlouhy/20.

A. No. As stated before, Staff does not believe that the comparison between the RAC and the CPP is fair and therefore does not necessarily warrant the same regulatory treatment. Further, Staff continues to hold the Commission's concerns in Order No. 22-388 that an overly generous RNG AAC mechanism would incentivize the Company to unfairly favor RNG investments in a way that may be detrimental to customers and that allowing this deferral would suboptimally shift both upside and downside risks onto customers.

Q. What reasons does the Company give to justify this deferral after the invalidation of the CPP?

A. The Company states that it still has a decarbonization obligation under ORS 468A.205 and will likely be subject to new laws or regulations concerning its customers' use of natural gas.[33] The Company believes that the deferral will allow it to balance interests of its shareholders and customers in pursuit of this goal.

Q. How does Staff's position on this issue change now that the CPP has been declared invalid over procedural concerns?

A. Staff remains unconvinced by the Company's updated arguments in Exhibit 2000 and believes that allowing a deferral between the in-service and rate-effective dates is even less appropriate now that the CPP has been declared invalid and a successor program is only in the rulemaking stage. Until a new set of rules to execute EO 20-04 are created, it is unclear how effective RNG will be as a compliance resource. As Staff has previously described, this

[33] NW Natural/2000, Kravitz – Therrien/11-12.

uncertainty can be attributed to the Company's own lawsuit that invalidated the CPP. While RNG acquisition would likely further the Company's decarbonization efforts in service of its obligations to a future CPP-like compliance program, Staff worries that allowing the proposed deferral would remove essentially all performance risk from the Company without a quantifiable benefit for customers.

Q. Regarding the Company's second proposed Schedule 198 change, what reasons does the Company give to justify setting the earnings test at authorized ROE?

A. The Company recommends that the earnings test be set at the Company's authorized ROE because the current structure provides a disincentive for projects that offtake more RNG than forecasted. The Company testifies that a project that produces more RNG than expected will have a lower per-unit cost but a higher overall revenue requirement due to the biogas contract being tied to the owner's production of biogas.[34] As a result, the Company may be forced to pay higher than forecasted costs for a project that is performing better than expected.

Q. Does Staff believe that this is a problem that can be solved with better forecasting or a one-sided adjustment to the forecast?

A. Not necessarily. While Staff expects that the Company's ability to forecast the productivity of its RNG projects will improve over time, Staff notes that there would still be differences between the forecasted and actual RNG production.

[34] NW Natural/1500, Kravitz – Chittum/18.

While it would be reasonable to expect that the Company absorbs trivial differences between the forecasted and actual costs, Staff notes that setting the earnings test at 50 basis points below ROE puts the Company in a regulatory bind that should be avoided.

Q. Why do you believe that 50 basis points below ROE earnings test may put the Company in a regulatory bind?

A. Staff believes it to be best practice to incentivize cost effective projects and to include only prudently incurred costs into rates. As the Company describes in its testimony, an RNG project that increases in total costs can also become more cost effective on a per-unit basis if it produces a high amount of RNG. Therefore, the Commission could incentivize high-upside projects by allowing the Company to provide higher RNG production forecasts and recover costs associated with higher RNG production.

This could result in a situation where the Company's over-forecasting allows it to systematically over-recover costs and retain the excess if the earnings test is not triggered. In this case, the Company would have a less effective project that underspends relative to the amounts included in rates, resulting in a situation where over-collected costs should be returned to ratepayers. If the Commission wanted to prevent this problem mainly through forecasting, it would adopt recommendations to forecast lower RNG production. This also presents a problem though, as these lower-production RNG projects are less likely to be considered cost effective in an RFP or prudence review.

Given the awkward push and pull between wanting to reward low per-unit-cost projects and wanting to maintain the lowest overall cost projects, Staff believes that a change to the earnings test for the RNG AAC may be warranted if the Company's characterization of the issue is correct or the magnitude of the costs associated with the volume of RNG is large enough.

Q. Does Staff believe that setting the earnings test for all costs at authorized ROE is the best way to address the issue raised by the Company?

A. No. It is worth reminding the reader that the total costs of the Company's current RNG projects are a mix between fixed costs and variable costs. Staff does not believe that an earnings test is appropriate for the recovery of the fixed costs associated with an RNG plant due to the perverse investment incentives identified by the Commission in Order No. 22-388. Staff believes that retaining the 50-basis point earnings test for these fixed costs is still optimal and could perhaps be optimal for all costs.

Q. How would Staff propose to address this issue while still being mindful of the perverse investment incentives identified by the Commission in Order No. 22-388 if the costs associated with the volumetric portion of each RNG project are substantial enough?

A. If the volumetric portion of the RNG costs subject to the AAC were substantial enough, Staff would recommend that the Commission subdivide the earnings test for the RNG AAC into two parts. The first part would consider the fixed costs recovered through the Company's RNG AAC; this earnings test would

remain at the existing 50 basis points below authorized ROE threshold. The second part would consider the volumetric costs recovered through the Company's RNG AAC; this earnings test would be set at the Company's authorized ROE. Staff believes that this would not over-incentivize RNG investment while still rewarding RNG projects that are more productive than expected.

However, Staff has reason to believe that these costs are trivial in the context of the overall revenue requirement of the RNG costs and thus do not rise to a high enough level of concern to warrant a change to the existing RNG AAC.

Q. How did Staff analyze which portions of the Company's forecasted costs related to its RNG project are fixed vs volumetric?

A. Staff issued a data request asking the Company to estimate the total cost of the Company's two RNG projects if the volume of RNG gas delivered was 20 percent above or below the amount forecasted.[35] Staff found that a change in the forecasted amount led to a trivial change in the overall project costs, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[36] According to the Company's response to Staff DR 459, a 20 percent increase in delivered RNG for Dakota City led to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and a 20 percent increase in delivered RNG for Lexington led to **[BEGIN**

35 Staff/907, Dlouhy/4.
36 Staff/907, Dlouhy/4.

CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]**to the overall project costs and recommends no changes to the existing RNG AAC.

Q. The Company also stated that it plans to develop RNG investments through the utility rather than the affiliate. Why does the Company propose to do this?

A. The Company proposes to make this change to its RNG acquisition strategy because the process can be administratively burdensome, and the Commission had previously expressed that the affiliate structure may require additional risk sharing in UG 462.[37]

Q. How was the risk sharing between the Company and its customers resolved in UG 462?

A. In UG 462, the Commission adopted the stipulation between all parties that allowed for customers to only pay up to 75 percent of costs above the stipulated benchmark of the average price per Renewable Thermal Credit (RTC) of the next two lowest bids from NW Natural's 2021 RFP.[38] This was due to concerns about risk allocation between the affiliate and NW Natural customers.

Q. What issues of risk allocation exist between the NW Natural's affiliate and its customers?

A. In theory, the affiliate structure provides some level of separation between the utility and the RNG projects. Given that RNG is an emerging field, there is

[37] NW Natural/1500, Kravitz – Chittum/14.
[38] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Renewable Gas Adjustment Mechanism - Dakota City,* UG 462, Order No. 23-367, Appendix A page 3 (October 16, 2023).

some benefit to insulating customers from a project that could become unwieldy if the project costs are borne in full by the affiliate. Conversely, the Company may be able to retain the excess profits in the event that a particular RNG project is overly successful.

That said, Staff has previously brought up concerns that the Company's chosen method of recovering the capital costs of the affiliate's investments rather than creating an off-take agreement essentially eliminates any of the customer risk mitigation benefits.[39]

Q. Does Staff see any benefit to the Company choosing to house these RNG investments under the utility rather than the affiliate?

A. Yes. Staff agrees with the Company that juggling the AI filing with the RNG AAC filing creates an administratively burdensome process that is hard to manage. AI filings have a statutory deadline to be addressed within 90 days of filing, and the prudence review for a new RNG project must be resolved prior to the November 1 rate effective date in the RNG AAC. It is entirely possible for issues in both dockets to be contingent upon decisions made in the other docket, but the timelines may not align to allow for the dockets to be properly consolidated. Further, Staff believes that it may be easier to scrutinize RNG project details and recommend O&M adjustments if the projects were under the utility's umbrella.

However, Staff also believes that the affiliate could be used more productively if the Company chose to structure the interaction between the

[39] UG 462 Staff/200, Drennan/10.

affiliate and the regulated utility differently. In particular as Staff has pointed out in the past, an affiliate-owned investment with an off-take agreement provides greater customer protection against both upside and downside risk.[40]

Q. Staff has previously recommended approving the use of an affiliate to Portland General Electric (PGE). How is this different?

A. Staff notes that the Commission has concerns about the usefulness of PGE's affiliate and only approved its use on a trial basis.[41] Notwithstanding, Staff notes that the affiliate was only approved with conditions to limit the ways in which the affiliate could operate and measures to ensure that customers remain unharmed should the structure not align with the Commission's goals. In that case, Staff notes that there were tangible investment tax credit (ITC) normalization consequences that translate to direct savings for customers. While some questions about risk sharing may apply to both NW Natural's and PGE's affiliates, Staff is unaware of a use case for NW Natural's affiliate that directly leads to savings for customers if the Company continues to recover the capital costs of the projects through rates.

Q. Does Staff believe that the Company should abandon using its affiliate for RNG acquisition?

A. It is unclear whether the Company should fully abandon the affiliate, but Staff believes that the affiliate is not currently being used in a way to shield customers form financial risk or maximize customer benefits. Staff notes that

[40] UG 462, Staff/200, Drennan/10.
[41] Order No. 23-294, page 1.

the ratepayer benefits of an affiliate entail the affiliate absorbing any positive or negative risks associated with a project that would otherwise be part of the Company's regulated operations. The structure approved in UG 462 of passing through 75 percent of added project costs above the benchmark puts risks back onto the Company's customers, thus diminishing the value of the affiliate in the eyes of the customer. Without the benefit of insulating customers from price shocks or output downsides, Staff doesn't see the value of using the affiliate for future RNG projects. However, Staff does believe that the affiliate could be valuable to the utility's customers if the risk sharing is fairly allocated between the Company's regulated and non-regulated entities.

Q. What is Staff's recommendation regarding the use of the affiliate in RNG acquisition?

A. At the moment, Staff recommends that the Company take one of two actions regarding its affiliate:

1. Stop using the affiliate and house all future RNG investments under the utility's regulated arm. If the Company were to do this, Staff notes that this would come with greater scrutiny about the prudency of the investments and the Company's choice to invest in RNG in a least-cost least-risk manner.
2. Continue to use the affiliate but structure any future agreement as an offtake agreement between the affiliate and the regulated utility. This would allow the Company to use the affiliate as intended while insulating customers from both upside and downside risk.

Docket No: UG 490

Staff/900
Dlouhy/26

Staff looks forward to reading other parties' testimony on the issue.

Docket No: UG 490

Staff/900
Dlouhy/27

ISSUE 3. RESIDENTIAL LINE EXTENSION ALLOWANCE

Q. What is the purpose of this section of your testimony?

A. The purpose of this section of my testimony is to respond to the Company's proposed changes to its residential line extension allowance program.

Q. What is a line extension allowance (LEA)?

A. As the Company describes in its opening testimony, LEAs are a general practice of providing new customers a discount to an existing natural gas or electric network. The traditional thinking is that these discounts, if quantified correctly, can benefit both new customers and existing customers by decreasing the cost of a new customer joining the system, which then leads to another customer on the Company's system who will be able to contribute to the recovery of the system's existing costs over time.

Q. How has the Company and the Commission treated residential LEAs prior to this case?

A. The Company currently uses a Revenue/Margin Multiplier approach for new residential customers, which was authorized in the Company's last general rate case.[42] Under this approach, the amount granted for a line extension equals a multiple of the annual expected non-fuel base distribution margin revenues.[43] In Order No. 22-388 in UG 435, residential LEAs were revised downward from the previous level of $2,875. The Commission directed the Company to calculate residential LEAs using a 5x margin approach with a cap of $2300. It

[42] NW Natural/1900, Therrien/8.
[43] NW Natural/1900, Therrien/6.

was also ordered that this amount would be lowered to a 4x margin on November 1, 2023, and then to a 3x margin on November 1, 2024.[44]

In making this decision, the Commission felt that the Company failed to integrate costs associated with new customers related to the CPP.[45] The Commission also felt that the Company's current LEA policy leaves unrecovered rate base even after 30 years of continued service.[46]

Q. How have natural gas LEAs been treated in other states with ambitious decarbonization mandates?

A. Staff Exhibit 903 contains recent orders from Washington and California, which both have decarbonization targets or mandates similar to Oregon's.

California's SB 1477 was signed into law in September 2018 and promotes building-related GHG reduction goals. After this was signed into law, the California Public Utilities Commission (CPUC) underwent a rulemaking to achieve "the State's goals of reducing economy-wide GHG emissions by 40 percent below 1990 levels by 2030 and achieving carbon neutrality by 2045 or sooner."[47] In furtherance of this goal, the CPUC eliminated residential LEAs and permitted non-residential LEAs only under special circumstances.[48]

Washington state passed the Climate Commitment Act (CCA) in 2021, which created a carbon cap-and-invest program to reduce the States' GHG emissions by 95 percent by 2050. In Docket UG 210729, the Washington

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44 NW Natural/1900, Therrien/8.
45 Order No. 22-388, page 48.
46 Order No. 22-388, page 49.
47 Page 6 of CPUC Decision 22-09-026 in Staff Exhibit 903.
48 Page 81 of CPUC Decision 22-09-026 in Staff Exhibit 903.

Utilities and Transportation Commission (WUTC) considered whether natural gas LEAs should continue to be calculated assuming that a customer stays on the natural gas system perpetually. This was done by creating a net present value (NPV) LEA calculation with no end date. In this proceeding, the WUTC determined that natural gas companies LEA NPV should be calculated using a seven-year timeline, which in effect lowered the allowable LEA substantially and better aligned LEAs with the legislature's intent with the CCA.[49] In UE-220053 in Washington, settling parties in Avista's joint natural gas and electricity rate case later agreed to fully phase out natural gas LEAs by January 1, 2025.[50]

Q. Does Staff believe that the outcomes and conclusions from California and Washington are relevant to the LEA discussion in Oregon?

A. Yes. Much like both of Oregon's west coast peers, Oregon has an ambitious decarbonization target through EO 20-04. Therefore, it behooves the Commission to take cues from other jurisdictions where natural gas LEAs were considered in the context of a decarbonizing economy. In particular Staff believes it may be in the Commission's best interest to either consider reducing the timeline used in the NPV calculation of the optimal LEA or eliminating residential LEAs entirely if one were to only compare Oregon to its peers.

However, Staff also conducted its own analysis to determine whether residential LEAs still appeared to be in the best interest of Oregon customers.

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49 Staff/903, Dlouhy/91
50 Staff/903, Dlouhy/99.

Q. How does this inform the Company's proposed updates to its residential line extension allowance?

A. The Company modeled the cost of CPP compliance in its updated residential LEA, as was directed in Order No. 22-388. To do so, the Company first changed its LEA calculation methodology to a Discounted Cash Flow (DCF) model wherein the Company calculates the LEA amount that would ensure that a new customer is neither subsidized by nor subsidizes existing customers. Underlying this method is the assumption that the new customer pays rates for some time horizon, thereby paying for existing assets that would otherwise only be paid for by existing customers. The use of a DCF model alone does not incorporate CPP compliance costs, but the Company also makes the following changes to incorporate these costs and update the model:

- An assumption that a new customer brings incremental expenses related to the CPP that are not already in base rates.
- An assumption that a new customer will help pay for additional CPP costs, which is incorporated as a credit in the model.
- Incorporate the new customer's contribution to new, non-growth capital and the decline in rates that occurs due to asset depreciation.
- Incorporate a higher fixed charge and new-customer fixed charge that would go into effect on November 1, 2024, if approved.

- An assumption that the DCF has a 25-year term rather than a 30-year term.[51]

Q. With these new assumptions in the model, what is the Company's new proposal for residential LEAs?

A. The Company's new residential LEA proposal is a four-tiered residential LEA based on expected usage. The Company breaks these four groups into customers expecting to use 0-250 therms, 251-450 therms, 451-650 therms, and over 650 therms per year. Following the invalidation of the CPP, the Company still assumes that it will have a future decarbonization obligation and assumes that the dollar value of the decarbonization obligation falls from the CPP CCA price of $123 per metric ton of CO2 to only $63 per metric ton of CO2.[52] This value was based on the price of a compliance instrument for the Washington Climate Commitment Act, which was the most expensive carbon credit that the Company was aware of in the US as of the publication of the Company's supplemental testimony filed on February 23, 2024.

At a high level, the inclusion of the costs associated with decarbonization makes residential customers with lower expected natural gas usage relatively more valuable to the system than customers with higher usage according to the Company's assumptions. The Company's updated proposed residential LEAs are included in its Exhibit 2000 and reproduced in the table below.

[51] NW Natural/1900, Therrien/19.
[52] NW Natural/2000, Kravitz – Therrien/18.

These represent a small increase in the LEAs proposed in the Company's opening testimony.

Table 1: NW Natural's Proposed Residential LEAs[53]

Supplemental Testimony Proposal				
Usage Tiers (therms)	0-250	251-450	451-650	650+
LEA	$3,700	$3,300	$2,950	$2,200

Q. What has Staff done to analyze the Company's proposed residential LEAs?

A. Staff began by first probing the Company's statement about what it believes makes a sound line extension policy and applied it to the current regulatory environment. This provided Staff with high level insights about the validity of LEAs as a general practice and ways in which the Company's model should be updated if one believes they should exist.

Staff then analyzed the Company's modeling choices to determine whether the updates to the LEA DCF model – both related to CPP costs and unrelated to CPP costs – appeared sound and appropriate.

Finally, Staff considered the equity and energy justice implications of LEAs and how it believes that these implications should fit into the Commission's overall direction on LEAs.

Q. Please summarize Staff's analysis of the Company's residential LEA proposal.

[53] NW Natural/2000, Kravitz – Therrien/23.

A. Staff believes that the Company's residential LEA analysis fails to take into account the true cost of CPP or decarbonization, best practices that Staff has pushed for in other dockets, or findings from other jurisdictions. Further, Staff does not believe that the Company's overall problem statement on line extensions is valid here, as a "least regrets" action may actually be taking actions to reduce customer count. Finally, Staff worries that line extensions could lead to greater stranded asset costs, which would likely inequitably harm future customers who are financially unable to electrify or otherwise decarbonize.

With this in mind, Staff recommends that the Commission take one of two actions. Staff's primary recommendation is that the Company stop its practice of offering residential LEAs. As an alternative recommendation, Staff recommends that the Commission maintain its previous decision on phasing out residential line extensions. Staff recommends the phase down follow the timing of having the residential LEAs to a level equivalent to the 2x margin beginning on November 1, 2025, and then 1x margin on November 1, 2026, then entirely eliminate residential LEAs by November 1, 2027.

Q. The Company states that one of the goals of a sound line extension allowance policy is to not subsidize new customers.[54] Is this goal accomplished if LEAs are eliminated?

A. Yes. If the Company eliminates line extension allowances, there are no concerns about existing customers subsidizing new customers.

[54] NW Natural/1900, Therrien/5.

Q. The Company also states that LEAs are meant to allow a level of investment from the natural gas utility commensurate with the incremental revenues from the new customer. [55] Do you agree with the Company's perspective that a line extension policy that supports new investments is necessary in the current regulatory climate?

A. No. While the Company makes a skewed attempt at incorporating decarbonization costs in its line extension allowance policy, the Company's analysis tacitly assumes that these new customers will remain on the system and that expanding or maintaining the Company's system is in the public interest. Although the CPP has been declared invalid, the Company still has aggressive decarbonization obligations through its own initiatives, ORS 468A.205, and EO 20-04 and the likely successor program to the CPP through the ongoing rulemaking.

In its last IRP, the Commission questioned the Company's optimistic assumptions around the availability of RNG and its outright refusal to consider electrification as a compliance resource for the CPP— which the Commission believes may potentially harm customers.[56] Staff believes the Commissions concerns remain valid and worries that a line extension allowance policy that continues to tacitly support future Company investments increases the potential for harm to befall the Company's customers through future stranded asset risk.

[55] Id.
[56] Order no. 23-281, pages 8-9.

Q. Why does Staff believe that the Company's LEA modeling fails to account for best practices or actual CPP costs?

A. Staff believes that there are multiple questionable assumptions in the Company's LEA DCF model that lead to an improperly large LEA. Namely:

1. The Company chose to use a 25-year payback period. Staff has advocated for a 20-year payback period in past dockets and the WUTC has recommended as little as a seven-year payback period. Given past feedback and the evolution of the LEA conversation, Staff finds it reasonable if not overly generous to use a 15-year payback period.
2. The later years in the Company's NPV model assume that the CPP compliance cost is based on RNG acquisition being the marginal resource and costing a fixed $22 per MMBtu. This is similar to the costs projected by the Company in LC 79 that Staff took issue with.
3. The Company's CPP revenue multiplier assumes that a new customer contributes more revenue to the Company's CPP compliance as the Company's CPP emissions cap decreases. This inherently assumes that the GHG emissions compliance obligations will be passed directly back to the new customer without any consideration of rate spread, rate design, or shareholder burden of decarbonization costs.
4. The Company's CPP model assumes the need for an exceptionally high amount of new non-growth capital expenditures that will be paid for by new customers. Despite Staff's concerns about the Company riskily choosing to invest in the system during a period of regulatory uncertainty,

Staff firmly disagrees with the Company's modeling of costs associated with non-growth capital.

5. The Company's model assumes that a residential new line extension is permanently occupied and paying rates. However, in reality there are likely periods where households remain unoccupied, thus not contributing to covering the Company's revenue requirement.

Q. Regarding your first point, why does Staff believe that a 15-year payback period is more appropriate than a 25-year payback period?

A. As Staff pointed out in UG 461, Staff believes that there is considerable payback risk if one assumes that a customer will continue to use the gas system after 20 years.[57] This could lead to a scenario where new customers are subsidized to join the Company's natural gas system, leave the system early due to future policies, energy preferences, or high natural gas prices, and then leave remaining customers to pay for stranded rate base investments that may not have otherwise been pursued. Even though the CPP has been declared invalid and a successor program is not finalized, Staff still agrees a shorter payback period is more appropriate than the Company's proposed 25-year payback period and its previous 30-year payback period. As Staff has expressed in this testimony, the Company still has its own decarbonization obligations through its own decarbonization targets, ORS 468A.205, and the new decarbonization program that is expected to be in place at the end of an ongoing rulemaking.

[57] UG 461 Staff/500, Bolton/9.

Staff finds that a 15-year payback period better captures Staff's concerns about stranded asset risks given the uncertain regulatory future created in part by the Company, and provides an upper bound for the possible system benefit of an LEA. Given the WUTC's mandate to use a seven-year payback period—before parties agreed to phase out natural gas LEAs entirely for Avista—and the CPUC eliminating LEAs entirely, Staff believes that a 15-year payback period is still perhaps on the longer timeline for the period over which calculating an LEA.

Q. How does changing the payback period affect the optimal LEA?

A. Lowering the payback period from 25 years to 15 years lowers the breakeven LEA in the Company's DCF model for all usage tiers. Due to lower-usage customers contributing less to CPP compliance costs than higher-usage customers in the last five years, the reduction in the breakeven LEA is felt most strongly in the lowest-usage tiers of the Company's proposed LEA.

Q. Regarding your second point, why do you believe that assuming a CPP compliance cost of $22/mmbtu is incorrect?

A. The Company states in its opening testimony that the $22/mmbtu is meant to represent RNG being the marginal CPP compliance resource. Staff notes that this cost is not far off from the Company's assumed cost of RNG acquisition in LC 79. The Commission raised multiple concerns about both the Company's RNG acquisition strategy and its modeling of RNG in LC 79,[58] and Staff

[58] Order No 23-281, Page 12.

expressed concerns in comments throughout the docket that the Company's modeling of RNG costs did not align with other RNG cost forecasts.[59]

Q. What do you believe is an adequate price to use to model RNG acquisition as the marginal CPP compliance resource?

A. Staff believes that assuming a compliance cost of $30/mmbtu is more reasonable. Staff arrived at this number by considering the costs presented in Table 3 of Staff's Final Comments in LC 79, which is reproduced below.[60] In particular, Staff notes that the Historic EPA D3 Cost ranges from a minimum of $22.46/MMBtu to a maximum of $40.95/MMBtu. S&P also provides estimates of RNG that range from $20/MMBtu to $35/MMBtu. Staff believes that assuming a compliance cost of $30/MMBtu is a suitable midpoint estimate of RNG costs outside of the Company's internal projections that Staff has previously been skeptical of.

Table 2: Staff's RNG Cost Projections in LC 79

	Price
Tranche 1 (1/3 of NWN RNG Supply)	Portfolio cost of $14/MMBtu
Tranche 2 (2/3 of NWN RNG Supply)	Portfolio cost of $19/MMBtu
S&P long-term utility purchase of RNG	$20-25/MMBtu
S&P Transportation RNG	$30-35/MMBtu
Historic EPA D3 Cost – minimum (1/4/2021)	$22.46/MMBtu
Historic EPA D3 Cost – maximum (1/3/2022)	$40.95/MMBtu

Q. Regarding your third point, what is the CPP Revenue multiplier in the Company's LEA DCF model and how is it calculated?

[59] Staff/905, Dlouhy/8.
[60] Id.

A. The Company's LEA DCF model assumes that as the CPP cap decreases, the costs associated with the cap rise. Additionally, the Company assumes that the revenues collected from the new customer rise in proportion to the ratio of the percent reduction in the cap in a certain year relative to the base year. This ratio is called the "CPP Revenue Multiplier" in the model. The value of the multiplier— which, by definition, varies between 0 percent and 100 percent— is multiplied by the CPP compliance costs added by the new customer to calculate the new CPP Revenues brought in by the new customer in the model. This is meant to represent new customers being responsible both for their additional CPP compliance costs and a share of future CPP compliance costs.[61]

Q. Do you agree with the way the Company chose to model these added CPP revenues?

A. No. The CPP revenues inherently assume that these new costs will be passed directly onto a new customer and the way that Company chooses to spread the recovery of new CPP costs is a foregone conclusion. It is very possible that these costs are not evenly recovered among the residential class, covered by entities outside of the residential class, or even passed on to the Company's shareholders if the costs associated with the continued practice of subsidizing new customers while needing to meet aggressive decarbonization obligations be considered imprudent or there exists another public policy reason to do so.

[61] NW Natural/1900, Therrien/30.

Staff, therefore, believes that the CPP revenues line item is a gross overestimation of revenues brought in by a new residential customer and therefore outputs a higher optimal LEA estimate than the DCF would if the more realistic assumptions were used.

Staff does however note that modeling the revenues generated to comply with the CPP is a tricky modeling exercise. For the purposes of this testimony, Staff leaves this line item unchanged as a bounding exercise. Due to this very generous assumption, Staff's resulting LEA estimates should therefore be interpreted as highest possible LEA to a new residential natural gas customer when incorporating CPP revenues.

Q. Regarding your fourth point, why do you disagree with the quantity of new non-growth capital assumed in the model?

A. As Staff has stated elsewhere, Staff believes that there is a very real possibility that the least-cost least-risk way to meet the Company's expected decarbonization obligations may be to reduce customer count. If this is indeed the least-cost least-risk strategy, then the amount of non-growth capital should reflect a declining system. However, in a period of regulatory uncertainty, Staff believes that there may be reason at the moment to model non-growth capital as if the customer count were static. Much like Staff's modeling choice for CPP revenues, Staff's choice to not adjust new non-growth capital expenditures downward should be treated as a bounding exercise to demonstrate the highest possible LEA.

Despite Staff's choice to keep non-growth capital expenditures modeled as if there were a static customer count, Staff believes that the Company overstates the amount of non-growth capital expenditures.

Q. Why does Staff believe that the amount of non-growth capital expenditures is overstated?

A. Staff inspected the underlying data that the Company used to model its non-growth capital expenditures, which was submitted in response to Earthjustice's Data Request 42. In a workpaper accompanying the response, Staff found that the Company nets out only some of the costs it classifies as being related to new customer acquisitions. While the costs associated with new mains and new services are removed from the capital expenditures, the Company still includes the costs associated with construction permits and meters and the revenues associated with retained contributions. These two items are clearly tied directly to adding a new customer to the Company's system and thus should be included in the Company's estimation of new non-growth capital expenditures. While the Company states that it excludes these costs in response to Earthjustice by reducing capital expenditures by $2 million, Staff found that this does not fully reflect the full effect of removing these costs. When these are included, Staff found that non-growth capital expenditures were overstated by approximately $25 million per year from 2024 through 2032.

Q. How did Staff choose to model the non-growth capital expenditures after including items that Staff believes the Company erroneously omitted?

A. Staff chose to model the omission of these costs as a decrease in new non-growth capital expenditures by $45 million each year through 2026 and $15 million in 2027 onward. Staff made this choice for two reasons. First, the Company's capital expansion workpapers showed a significant decrease in capital expenditures from 2027 onward, indicating a behavioral breakpoint in capital expenditures that should be preserved for modeling accuracy. Second, Staff notes that the Company's LEA DCF model shows a change in capital expenditures from 2027 onward, so Staff believes it best to be consistent with the Company's modeling choices as much as possible.

Q. What is the effect of including these items in the Company's capital expenditures included in the Company's DCF model?

A. Reducing the Company's capital expenditures in the DCF model reduces the amount of plant that a new customer helps pay for, which in effect reduces the size of the calculated LEA.

Q. Regarding your fifth point, why does it matter that a new connection has stretches where it is unoccupied when calculating an optimal LEA?

A. As the Company models them in their DCF workpapers, line extension allowances assume a new customer is continuously paying rates, thereby contributing to the cost recovery of base rates and lowering the revenue

requirement burden for existing customers. If a new line extension is paid for but the home is not yet occupied for a stretch of months or a customer moves and leaves a residence unoccupied for a stretch of months, then the value of the new customer to the system is diminished.

Q. Do you have evidence that a new residence granted a line extension has a period where it is unoccupied before the new customer moves in?

A. Yes. In response to Staff DR 135, the Company notes that there is a typical delay of three to six months from the time between a line extension installation and the time that the customer begins to take service, with the expected time being approximately four months.[62] This means that the first year of customer revenues in the Company's NPV calculation likely accounts for approximately four months' worth of revenues that do not actually occur, which would overstate the system value of the line extension allowance.

To account for this in Staff's modifications to the Company's LEA DCF workpapers, Staff reduces the distribution revenues in the first year by two-thirds to reflect that the Company is unlikely to begin receiving customer bills from a new line extension for approximately four months. In effect, this lowers the system value of a new residential LEA.

Q. Do you believe that Staff's adjustment to the first four months of the Company's LEA DCF model fully address the overvaluation problems that arise from a residence being unoccupied?

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62 Staff/902, Dlouhy/3.

A. No. As stated previously, it is likely that a residence is not continuously occupied throughout the entire fifteen-year period that the new customer is assumed to be billed. While there are likely certain types of dwellings such as rental apartments where this is a large problem and owned single-family residences where this is less of a problem, Staff chose not to model this for the sake of feasibility. Given that the resulting model still overstates the months when a dwelling is occupied and a customer is paying natural gas bills, Staff's change only partially reflects the diminished value of a residential LEA relative to the Company's filed model.

Q. Does Staff make any other changes to the Company's LEA DCF model?

A. Yes, Staff makes the following changes to the Company's model to reflect our recommendations on other topic areas.

- Staff lowers the basic charge for a newly connected customer from $26.25 to $10. Staff Witness Eric Shierman discusses Staff's opposition to the new customer basic charge in Staff Exhibit 1800. In effect, this lowers the optimal LEA substantially.
- Staff updates the ROE and long-term cost of debt to reflect Staff's conservative alternative to the midpoint ROE in its opening testimony as well as stipulated agreements. The effect on the optimal LEA from this change is minimal.

Q. Based on all the changes Staff made to the Company's LEA DCF model, what does Staff believe to be the optimal residential LEA under the Company's current tiered LEA framework?

A. Staff's full DCF model can be found in Staff Exhibit 903. Based on these changes, Staff finds that at all tiers, a line extension *disallowance* is justified at every usage tier even with assumptions that Staff views as overly generous. Table 3 contains a summary of the calculated LEAs for each usage tier using Staff's edits to the Company's LEA DCF model.

Table 3: Staff's Residential LEA by Usage Tier

Model Results at Proposed Consumption Levels (Therms)				
UPC (Therms)	250	450	650	1,000
LEA	-$144	-$1,284	-$2,424	-$4,419
Times Margin	-0.4	-2.4	-3.4	-4.3

Q. Are there additional equity or energy justice reasons that it may be in customers' best interest to end the practice of natural gas residential LEAs?

A. Yes. Staff notes that a likely outcome of decarbonization is a decrease in natural gas use. Even if natural gas use falls across the Company's system, assets and other fixed costs will still be in base rates and contribute to revenue requirement. Even if these assets are not technically stranded assets, it is possible that customers who are induced to join the natural gas system now will be on the hook to pay for these assets in the future even if their usage declines. As these costs accumulate and compliance costs with a possible successor program to the CPP rise, one would expect that customers who have the means to switch away from natural gas will choose to do so for economic reasons or other personal preferences. In effect, this may result in

only customers with the lowest ability to leave the natural gas system stuck paying for system costs that they may not have had a part in.

A recent paper from Lucas Davis and Catherine Hausmann found that a ten percent decrease in natural gas utility customer count only results in a five percent decrease in utility revenues, with remaining customers left paying for the difference.[63] Staff finds that the potential exacerbation of energy justice concerns is yet another reason to view removing residential LEAs as a "least regrets" outcome at the moment.

Q. What is your recommendation for residential LEAs?

A. Staff recommends that the Commission take one of two actions. Staff's primary recommendation is that the Company stop its practice of offering residential LEAs. Staff believes this to be in the best interest of customers at the time given the regulatory uncertainty surrounding the successor program to the CPP and the results of Staff's model indicating that a line extension disallowance would be in customers' best interest even with the most generous assumptions.

As an alternative and more conservative recommendation, Staff proposes the Commission maintain its current policy that identified a phase down to the residential LEAs. Such a phase down could be to a level equivalent to the 2x margin beginning on November 1, 2025, and then 1x margin on November 1, 2026, and then entirely eliminate residential LEAs by November 1, 2027.

63 Staff/903, Dlouhy/177.

Docket No: UG 490

Staff/900
Dlouhy/47

ISSUE 4. METER MODERNIZATION PROGRAM

Q. What is the purpose of this section of your testimony?

A. This section addresses the Company's proposed meter modernization program contained in the Company's Exhibit 900.

Q. Please summarize the Company's proposed Meter Modernization Program (MMP).

A. The Company's MMP is an initiative undertaken by the Company to replace portions of its aging metering system. The MMP would replace meters that run "fast" – known as Periodic Cause for Change (PCC) meters – and failing Encoder Receiver Transmitter (ERT) devices.[64] In addition to these two main categories, the Company intends to replace its meter reading software and incorporate newer, ultrasonic meters.[65]

As part of the MMP, the Company also requests three new FTEs to run a new software suite, manage workstreams, and manage the meters' expanded AMI capabilities.[66]

The Company proposes to recover an Oregon-allocated $69.2 million in this rate case and the remainder of the capital costs of the four-year project through future rate cases and the Company's proposed multi-year rate plan.[67] The Company also proposes to use a deferral to capture the substantial but

64 NW Natural/900, Karney/3.
65 NW Natural/900, Karney/3-4.
66 NW Natural/900, Karney/34.
67 NW Natural/900, Karney/37-38.

short-lived O&M costs to deploy these meters rather than recover the costs through base rates.[68]

Q. What does it mean for a meter to run "fast" and what is the Company's criteria for a meter that runs too fast?

A. As the Company describes in its opening testimony, a "fast" meter is a meter that reads a higher volume of natural gas consumed than is actually consumed. A meter is determined to be PCC-eligible if it reads at least 102 percent of the actual metered volume of gas.[69] Existing meters that read between 98 and 102 percent of the actual volume of gas and new meters reading between 99 and 101 percent of actual volumes of gas are determined to be accurate.[70]

Q. Does Staff have any issues with these criteria to determine a fast or accurate meter?

A. Not at this time. Staff notes that the Company's forecasted average use per residential customer in the Company's territory is 660 therms in the test year.[71] A two percent increase in billed volume over the course of the year under the existing tariff rate of $1.29519/therm would improperly charge customers with a fast meter an additional $17 per year.

However, Staff was initially concerned that more could be done to verify whether replacing the family was the right decision ex post. Staff issued a data

[68] NW Natural/900, Karney/39.
[69] NW Natural/900, Karney/7.
[70] NW Natural/900, Karney/8.
[71] NW Natural/1800, Wyman/21.

request asking whether the Company does any analysis on the meters after an entire family is replaced. Based on the Company's response to this data request, the Company does do ex post testing that has indeed resulted in keeping meters in service that were previously thought to be PCC meters.[72]

Q. How does the Company determine which meters need to be replaced?

A. The Company designates all its meters pre-2020 into various families and subfamilies based on the manufacturer, meter characteristics, and the date that the meter is placed in service. Post-2020, families are made solely on the meter manufacture date.[73]

Within each family, the Company selects randomly sampled meters that are taken out of service and tested off site. The Company then determines whether more than 80 percent of meters are deemed to be accurate and more than 90 percent are deemed to be fast by taking into account family size and conducting additional testing on 10 year or older meters if needed. A meter family that is either fast or not accurate is a candidate for being changed out by the Company's criteria.[74]

Q. How long does the Company have to replace meters and how many meters has the Company identified for replacement?

A. The Company has four years following its annual Meter Sampling Report filed in RG 41 to remove any non-conforming meters identified in the report. The Company identifies almost 90,000 PCC meters that must be replaced by

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72 Staff/902, Dlouhy/7.
73 Id.
74 NW Natural/900, Karney/9-10.

2026.[75] Additionally, the Company identified approximately 500,000 ERTs contained in the Company's meters that are expected to reach the end of their useful life between now and 2027.[76]

Q. Does the Company plan to replace their current meters with a similar design?

A. In part. The Company's Oregon territory is comprised of almost exclusively diaphragm meters, which uses mechanical components to measure the flow of gas. As part of the Company's MMP, the Company proposes utilizing an equal mix of diaphragm meters and ultrasonic meters.[77]

As the Company describes in its opening testimony, these meters are generally more accurate, have more reliable useful lives, and require less maintenance.[78] Overall, the Company plans to deploy approximately 40,000 diaphragm meters and 50,000 ultrasonic meters.[79]

Q. Please summarize the timeline, expected costs, and cost recovery plan for the Company's proposed MMP?

A. The Company expects the MMP to take approximately four years and plans to roll out the MPP in six batches:

- Batches 1-2: Urban areas that don't benefit as much from the ultrasonic cellular meters, such as Eugene and Corvallis.

[75] NW Natural/900, Karney/12.
[76] NW Natural/900, Karney/3.
[77] NW Natural/900, Karney/26.
[78] NW Natural/900, Karney/19.
[79] NW Natural/900, Karney/35.

- Batches 3-4: Rural and coastal areas that will primarily use the ultrasonic cellular meters from Itron. This batch is being deployed later than the first two batches to accommodate Itron's production timelines.
- Batches 5-6: Primarily replacing the PCCs and ERTs in the Portland metro area.[80]

The Company explains that rural and coastal areas are generally harder to reach for the Company's field crew and will likely benefit more from the remote shutoff capabilities of the ultrasonic meters in the event of disasters such as wildfires or tsunamis.[81]

Q. What does Staff think about the Company's prioritization of meter replacements and choice of where to use its various types of meters?

A. While Staff has some concerns about continuing to switch to primarily ultrasonic meters, Staff thinks that the Company's choice of where to deploy ultrasonic meters is sensible in some cases. Staff understands that servicing a meter in a remote location is relatively more costly than doing so in an urban environment and believes that it is prudent to prefer a slightly higher capital cost meter with lower O&M expenses in this circumstance.

However, Staff holds concerns about whether using ultrasonic meters across the Company's entire service territory would be in customers' best interest should the Company choose to move in that direction in the future. As the Company describes in its opening testimony, ultrasonic meters have a

[80] NW Natural/900, Karney/35.
[81] NW Natural/900, Karney/36.

useful life of approximately 20 years.[82] Based on the Company's response to Staff's data requests, these meters would need to be replaced in their entirety at the end of their useful lives.[83]

However, diaphragm meters generally have a suite of replaceable parts that can extend the useful life of the meter beyond the expected service life and in circumstances where a single component fails.[84] Further, diaphragm meters have an expected useful life of 30 years as opposed to the ultrasonic meter's 20-year useful life.[85] While O&M or warranty considerations may not make diaphragm meters the best option in all cases, Staff expects that there will be many cases moving forward where continuing to use diaphragm meters is a more cost effective way to provide service than a full ultrasonic meter conversion.

Q. Does this mean that Staff is supportive of the Company's MMP?

A. Not entirely. In relation to Staff's thoughts regarding the CPP, the RNG AAC, and the residential LEA, Staff is skeptical whether it is in the customers' best interest to undertake an aggressive initiative to replace and upgrade all the Company's meters at this time. As part of the Oregon's and Company's decarbonization goals, Staff expects that some amount of NW Natural customers will voluntarily choose to electrify for either personal or economic reasons. Any customer that receives a meter replacement and opts to fully

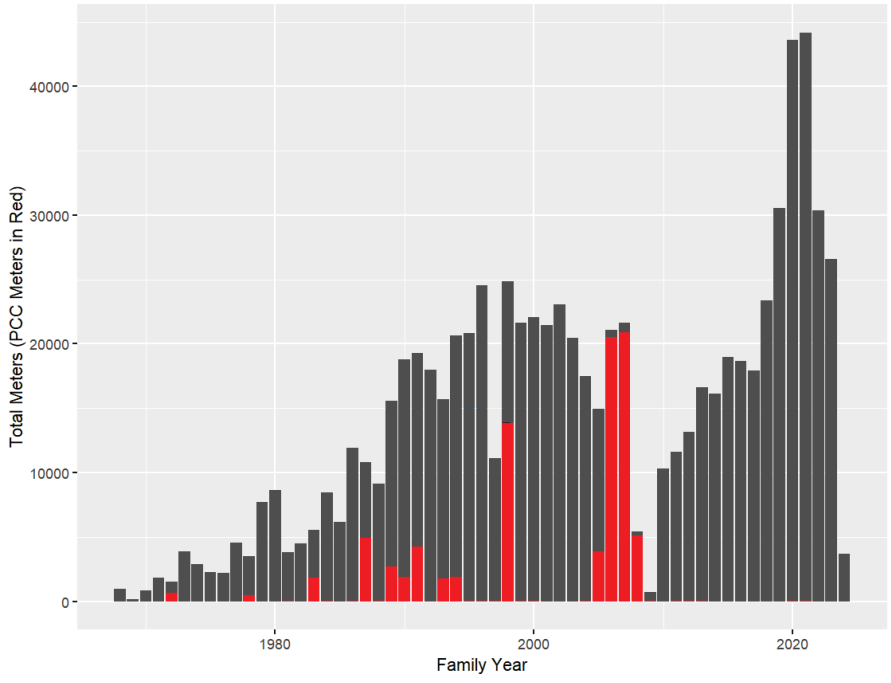
82 NW Natural/900, Karney/19.
83 Staff/902, Dlouhy/5.
84 Staff/902, Dlouhy/4.
85 Staff/902, Dlouhy/10.

electrify before the end of the new meter's service life will necessarily leave stranded asset costs that remaining customers are responsible for paying.

Q. Are there other reasons that Staff has concerns about allowing the Company to fund the replacement of meters through ratepayers?

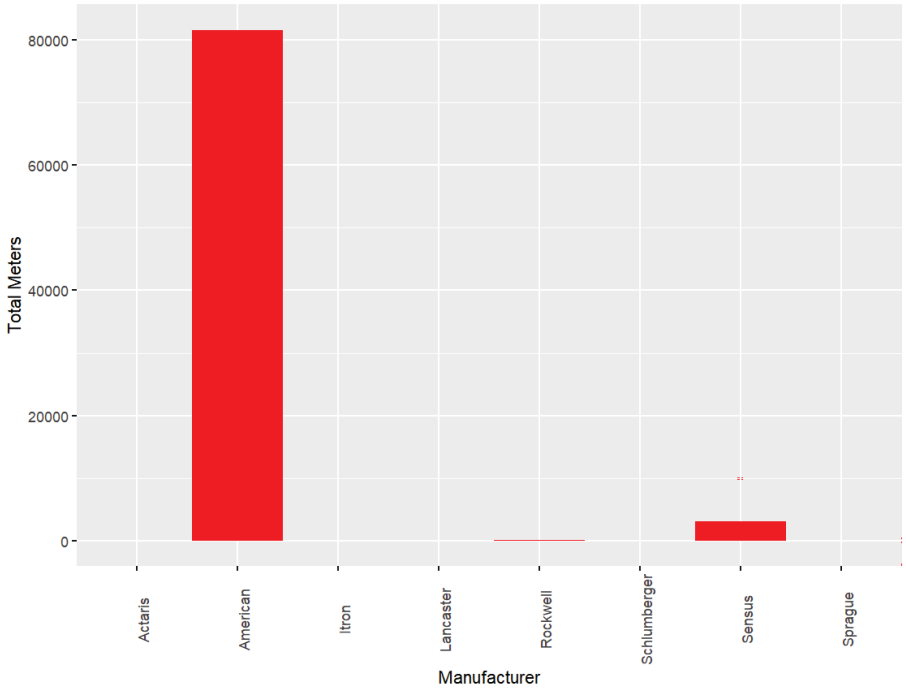
A. Yes. The bulk of the Company's PCC meters appeared to have failed between 2005 and 2008 and seem to come almost exclusively from a single manufacturer. Figure 1 presents a histogram of the Company's meters by their installation year and highlights the quantity of PCC meters within each installation year. The data presented in Figure 1 was compiled from the Company's response to Staff DR 382.

Figure 1 Total Meters and PCC Meters By Family Year



As can be seen in Figure 1, most meters flagged as PCC meters were installed between 2005 and 2008. Figure 2 presents the quantity of PCC meters by manufacturer.

Figure 2: PCC Meters by Manufacturer



Staff notes that the manufacturer American is also known as Honeywell. It can clearly be seen that the bulk of the meters came from American.

Q. Why does the Staff have concerns about the timing of the meter installations?

A. In its response to Staff DR 387, the Company stated that it typically has a 15-year warranty for its meters.[86] Staff notes that many of the PCC meters have been in service for just over 15 years, calling into question whether the

[86] Staff/902, Dlouhy/8.

Company was aware of the problem during the warranty period or should have been aware.

Further, based on the Company's response to DR 387 and discovery from previous dockets, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Q. Does Staff think that the Company could have been aware of these fast meters during the warranty period for the meters?

A. In some cases, yes. Staff Exhibit 906 contains the Company's RG 41 filings from the last four years. Within each year, there are a non-trivial number of meters in each filing that have been in service for less than 15 years.

Q. Has the Company pursued a warranty claim for any of these meters?

A. Yes. According to the Company's response to Staff DR 301 from UG 435, which the Company has provided with its response to Staff DR 387 in this docket, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Staff issued a follow up data request to

determine when these replacement meters were bought or placed in service. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[87] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[88]

Q. Does Staff believe that the Company should have investigated other meters from the manufacturer that is responsible for the defective meters?

A. Yes. Staff notes that not only did the Company identify an entire batch of meters from American that it eventually got refunded through a warranty claim, but the Company also installed a large number of meters from the same manufacturer in each of the prior four years. Staff believes that it would have been a reasonable and prudent step to investigate whether these meters were also systematically running fast given that they came from the same manufacturer and have a similar vintage. Given the large confluence of meters from the same manufacturer that also failed the Company's inspection in such a similar timeframe, Staff is concerned that the Company did not properly

87 Staff/907, Dlouhy/8.
88 Staff/907, Dlouhy/9.

investigate this issue to determine whether it should pursue a warranty claim for these meters prior to the warranty expiring.

Q. What is the net book value of these meters and does the Company intend to remove the net book value of these meters from rate base?

A. It is difficult to exactly determine the net book value of these meters because the Company relies on group depreciation and groups all meters that were put into service in the same calendar year into a single group. Based on the Company's response to Staff DR 461, Staff estimates that the net book value of the PCC meters put into service from 2005 to 2008 to be approximately $9.3 million. Based on the Company's response to Staff DR 462, this amount would continue to be recovered through base rates based on common group depreciation practices.[89]

Q. Why does Staff believe that it is proper to take this amount out of rate base despite common group depreciation practices?

A. As stated previously, Staff believes that the Company could have caught these meters and replaced them under warranty had their quality control been more proactive. Further, Staff questions whether it is in the best interest in customers to replace these meters rather than to merely repair and redeploy them. Therefore, Staff believes that it is improper to fall back on depreciation practices that assume entirely probabilistic asset survival rate.

Q. How does Staff calculate this value?

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89 Staff/902, Dlouhy/12.

A. Staff issued a data request asking for the net book value of meters in each family year. The Company explained to Staff that it uses group depreciation for its meters and could only provide the net book value at the installation year level and provide an average unit cost for the entire year. Using this information, Staff found the average book value of meters in the 2005 to 2008 range and multiplied that by the number of the PCC meters identified by the Company in these years. Staff made this choice after noticing that the in-service year in the Company's Attachment 2 to its response to Staff DR 461 did not perfectly align with the PCC meters by family year in Attachment 1. While Staff believes that this provides a reasonable estimate of the net book value of the meters that should be removed from rate base according to Staff's analysis, Staff welcomes other intervenors or the Company to provide a more accurate methodology to calculate the impact of removing the net book value of these meters from rate base.

Q. The Company states that it chose to replace drifting meters rather than propose a drifting adjustment due to the Commission's opposition to the adjustment in UG 461 and because the ERTs would need to be replaced anyway.[90] Do you think this is sufficient justification to replace PCC eligible meters?

A. Not entirely. Staff highlighted issues with the drift adjustment in UG 461 and the Company notes that it could not impose a drift adjustment if a meter's ERT

[90] NW Natural/900, Karney/32-33.

fails.[91] While Staff understands that there may be instances where it makes sense to replace a PCC meter, that this may be less cost effective than merely replacing the ERT and applying a drift adjustment. Given Staff's concerns about significant stranded asset costs, Staff believes the latter method may be more prudent.

According to the Company's opening testimony, the Company entered into a $28.8 million agreement with Itron to purchase approximately 400,000 ERTs over the coming years.[92] This amounts to a unit cost of approximately $72 per ERT, whereas a new ultrasonic meter with a new ERT costs $200.[93] Further, it is Staff's understanding that a new ultrasonic meter must be entirely replaced at the end of its useful life whereas a diaphragm meter can be refurbished or kept in service. Staff also points out that many of NW Natural's diaphragm meters are still in service well over 30 years. Staff questions whether it is in customers' best interest fully replace a PCC meter and its ERT rather than apply a drift correction and replace the ERT at a third of the cost.

Q. Does Staff have any objections to the three new FTEs related to the MMP?

A. Not at this time.

[91] NW Natural/900, Karney/33.
[92] NW Natural/900, Karney/35.
[93] NW Natural/900, Karney/19.

Q. The Company states that it intends to recover the capital costs of the MMP through a multi-year rate plan and the O&M costs through a deferral.[94] Does Staff agree with this approach?

A. While Staff has raised concerns about the cost effectiveness of the Company's MMP, Staff agrees with the Company that the O&M costs are likely better recovered through a deferral. It is Staff's understanding that the O&M costs are likely to be substantial and short term, meaning that there is risk of the Company over-collecting costs to fund the MMP if the costs remain in base rates and the Company stays out of a rate case for an extended period of time.

Q. Please summarize Staff's take on the Company's Meter Modernization Program.

A. Staff believes that the Company's Meter Modernization Program addresses some of the Company's needs, albeit not necessarily in the most cost-effective manner. Staff takes no issue at this time with the Company's plan to replace ERTs on meters that are nearing the end of their life.

However, Staff is skeptical of the value of transitioning to primarily ultrasonic meters in the long term. As the Company has stated, the more expensive ultrasonic meters have fewer replaceable parts than the existing diaphragm meters and will likely need to be replaced in full at the end of their service life whereas a diaphragm meter is cheaper and may be repaired and redeployed. While Staff believes that there may be appropriate use cases for ultrasonic meters, Staff is wary of investing in the highest-grade technology in

[94] NW Natural/900, Karney/38-39.

an era where the Company is faced with many decarbonization obligations that threaten to drive down the system value of the more expensive and nascent technology.

Staff is also concerned that the Company is replacing many of these meters well before the end of their useful life while keeping the remaining net plant of the meters in rate base. This concern is heightened by Staff's worry that the Company's meter testing practices failed to catch many PCC meters in the 2005-2008 family years while they were still under warranty. Staff recommends that the remaining net book value of the PCC meters in the 2005-2008 family years be removed from rate base to account for Staff's concerns about further building out the gas system in an era of decarbonization and about its concerns that the Company did not do enough to fully investigate the accuracy of these meters while they were still under warranty.

Q. What is Staff's overall adjustment regarding the Company's Meter Modernization Program?

A. Staff's adjustment lowers the Company's Oregon-allocated rate base by $9.316 million to reflect the net book value of PCC meters in the 2005-2008 family years.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 490
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 901

Witness Qualifications Statement

April 18, 2024

Docket No. UG 490

Staff/901
Dlouhy/1

WITNESS QUALIFICATION STATEMENT

NAME: Curtis Dlouhy

EMPLOYER: Public Utility Commission of Oregon

TITLE: Economist, Strategy and Integration Division

ADDRESS: 201 High St. SE, Ste. 100
Salem, OR 97301-3612

EDUCATION: PhD, Economics
University of Oregon,
Eugene, OR

Master of Science, Economics
University of Oregon,
Eugene, OR

Bachelor of Arts, Economics & Math
Nebraska Wesleyan
University, Lincoln, NE

EXPERIENCE: I have been employed by the Oregon Public Utility Commission (OPUC) in the Strategy and Integration Division since April 2022 and had previously worked in the Rates, Finance, and Audit Division since June 2020. My responsibilities include providing research, analysis, and recommendations on a range of regulatory issues. I have provided analysis and expert testimony in various contested cases including UG 388, UG 389, UG 390, UE 374, UE 390, UE 391, UE 394, UG 433, UG 435, UE 399, UE 400, UE 402, UE 416, UE 420, UE 427 (ongoing), and UG 490.

Prior to working for the Commission, I was employed by the University of Oregon as a graduate employee where I taught classes in Intermediate Microeconomics, Industrial Organization, and Antitrust Economics. My PhD dissertation won an award from the Transportation and Public Utility Working Group and covered topics in fossil fuel markets ranging from coal mine closure, dispatchable electricity choices under carbon taxes, and coal transport via railroad. While completing my PhD, I provided economic analysis for the Graduate Teaching Fellows Federation as a member of its contract bargaining team.

CASE: UG 490
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 902

Non-Confidential Responses to Data Requests in Support Of Opening Testimony

April 18, 2024

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 Coalition DR 42

Please provide all documents and data provided by NW Natural to Mr. Therrien which he relied upon to prepare NW Natural Exhibits 2000, 2001, 2002, 2003, 2004, 1900, 1901, 1902, 1903, 1904, 1905, 1906, 1907.

Response:

The Company objects to this data request under 860-001-0500 because the request for "all documents and data" is burdensome, overly broad and not commensurate with the needs of this case, the resources available to the parties or the importance of the issues to which the discovery relates. NW Natural also objects on the basis that some of the information requested includes attorney-client privileged information and attorney work product; the attachments to this response are compiled to not contain attorney-client privileged information or attorney work product. Without waiving these objections, the Company responds as follows:

Please refer to UG 490 OPUC DR 378 Attachment 1 and Attachment 2. The tabs, "Input Output - Exh. 1905" and "Input Output - Exh. 1905R (2002)" in Attachment 1 and 2, respectively, indicate data that the Company provided to Concentric Energy Advisors for the exhibits cited above. The data sources are consistent between both attachments. These files can be referenced as follows:

- UG 490 Coalition DR 42 Attachment 1: CPP Proxy Cost for Revised LEA Model.xlsx. Data input: CPP Cost ($/Therm).

- UG 490 Coalition DR 42 Attachment 2: DEQ Compliance schedule - 121621_AttachmentE_Locked.xlsx. Data input: CPP Revenue Multiplier (Annual Cap Percent Change).

- UG 490 Coalition DR 42 Attachment 3: Capex for LEA Analysis.xlsx. Data input: Forecasted System Capex. The "Summary" tab references "Per Jorge email." The referenced email from Jorge Moncayo, NW Natural's Business Planning Senior Director – Financial Analysis, described the $2 million/year reduction of the capex numbers to reflect the cost of meters and permits related to new growth, in keeping with the objective of determining future non-growth related capex. It also explained that for years beyond 2032, the capex for 2032 could be used as a proxy.

- UG 490 Coalition DR 42 Attachment 4: 2023 Plant Workpaper.xlsx. Data inputs: Gross Plant and Accumulated Depreciation.

- UG 490 Coalition DR 42 Attachment 5: NWN Depreciation Rates for Concentric.xlsx. Data inputs: Depreciation Accrual Rates.

- UG 490 Coalition DR 42 Attachment 6: NWNG Earnings Review Filing 12-31-2022.pdf. Data inputs: Deferred Taxes, Operations & Maintenance, and Net Utility Plant.

- UG 490 Coalition DR 42 Attachment 7: Workpapers_2022 IRP Scenario Results_v2 (1).xlsx. Data inputs: Customer Count.

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 135

Please provide the expected length of time between a residential line extension being fully installed and a residential ratepayer's service with the Company beginning.

Response:

The Company has different expectations for the length of time between a residential line extension installation and when a residential customer is taking service (e.g., when a billing meter is installed and reporting load), depending on market segment. The expected timeline by market segment is as follows:

- Residential conversion services: Three months.
- Residential new construction subdivision services: The billing meter is typically set at the time of service installation, and if not, it is set within three months. The meter is generally set at the time of installation to provide dry-out services to the premise under Rate Schedule 27 Residential Heating Dry-Out Service.
- Residential new construction infill / spot lot services: These projects can occur over longer cycles relative to conversion and new construction subdivision services, but typically billing meters are set within three to six months.

Further, in its estimation of a New Premise Use-per-Customer ("UPC"), the Company found that "in general there is a about a four-month delay between when a [residential] service is initialized and when the bills show therm load.."[1] which is consistent with the Company's expectations described above. For a narrative summary of this analysis, please refer to NW Natural/1800, Wyman/21-24.

[1] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 490, Exhibit NW Natural/1800, Wyman/22, lines 1-3 (December 29, 2023).

Docket No. UG 490

Staff/902
Dlouhy/4

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 380

Please discuss whether an entire diaphragm meter must always be replaced at the end of its expected useful life. If it does not, please provide a list of individual components that may be replaced to extend the useful life of the meter, the useful life of these components and the cost of these components.

Response:

No, a diaphragm meter does not need to be replaced when it reaches its expected useful life. For example, if a diaphragm meter is performing normally, it may remain in service fully depreciated for many years after its expected useful life.

A diaphragm meter is considered at the end of its useful life when it must be removed from service. This includes, but is not limited to, when the meter has been declared non-conforming (PCC) by the Meter Sampling Program, if the meter is damaged or otherwise inoperable, the service is being relocated, the meter is sized incorrectly for the load, or if the meter family size is so small that statistical sampling is impractical.

Regardless of the reason for removal, NW Natural replaces these end-of-life diaphragm meters and does not refurbish them. The primary reason for utilizing new meters versus refurbished is that a refurbished meter carries a 1-year warranty, whereas a new meter is given a 15-year warranty from the manufacturer.

Docket No. UG 490

Staff/902
Dlouhy/5

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 381

Please discuss whether an entire ultrasonic meter must always be replaced at the end of its expected useful life. If it does not, please provide a list of individual components that may be replaced to extend the useful life, the useful life of these components and the cost of these components.

Response:

The ultrasonic meter package has a 20-year life including the meter, RF communications and valve, and we would expect to replace entire meter at that point. Please see NW Natural/900, Karney/Page 19, Lines 9-10.

NW Natural®

Rates & Regulatory Affairs

UG 490

Request for a General Rate Revision

Data Request Response

Request No.: UG 490 OPUC DR 382

For each family and subfamily of meters currently in service, please provide:

a. The quantity of meters in the family
b. The In-Service Year for the family
c. The meter manufacturer
d. The cost to purchase each meter
e. The O&M costs associated with installing the meter
f. A description of the geographic area(s) where the meters were installed.
g. An indicator about whether the meter family or subfamily is set to be replaced due to ERT replacement or PCC.

Response:

In response to a follow-up inquiry from the Company, the Staff Initiator of this data request clarified that Staff is requesting aggregated meter information at the family level for all meters. In response to the clarified data request, please see UG 490 OPUC DR 382 Attachment 1 for a comprehensive list of meter families, their in-service year, meter manufacturer, the geographic area where the meter is installed (by Company District) and the number of meters that require ERT replacement or have been declared non-conforming (PCC) and require complete meter replacement. This list is inclusive of the meters in the Company's Meter Sampling Program, which is reflective of approximately 99% of installed meters.

Please note that the list of meters in UG 490 OPUC DR 382 Attachment 1 were developed in response to this data request and will not perfectly tie out to the Company's initial filing in this case because the meter modernization program is already underway and the numbers have changed since that time.

In response to a subsequent follow-up inquiry from the Company, the Staff Initiator of this data request clarified that for subparts (d) and (e), the Company may provide an estimate of expected current costs for the purchase of a new meter (subpart (d)) and with the installation of a meter (subpart (e)). Regarding subpart (d), please see the Direct Testimony of Joe S. Karney, NW Natural/900, Karney/Page 19, Lines 11-15. Regarding subpart (e), please see the Company's response to UG 490 OPUC DR 124.

Staff/902
Docket No. UG 490 Dlouhy/7

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 386

Please discuss whether the Company performs any ex post testing on a family of PCC meters that were removed.

Response:

NW Natural performs accuracy testing on each meter that is removed from service, including all PCC meters. These test results are recorded for each meter in the Company's Customer Information System. To evaluate the accuracy of the Meter Sampling Program statistical analysis, these test results are periodically evaluated to ensure that the PCC meters being removed from service exhibit the same performance characteristics of the sample meters upon which the PCC determination was based. If the test results from PCC meters removed from service exhibit statistically significant differences from the sample meters, the Company performs additional analysis to determine the reason for the difference.

An example of this analysis was discussed in the Company's RG 41 Annual Meter Sampling Program Report for 2022, included here as UG 490 OPUC DR 386 Attachment 1. A modification to the 2005 Perf #572 Sensus R-275 meter family was made after evaluating meter tests for PCC meters removed from service, where specific delivery lots for these meters were determined to be non-conforming, while others were determined to be conforming, resulting in reducing the number of PCC meters by 6,673. NW Natural continues to evaluate performance of all meters removed from service to ensure accuracy and compliance with the Meter Sampling Program.

Docket No. UG 490

Staff/902
Dlouhy/8

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 387

Please discuss whether the Company pursues any warranty claims in the event that a family or subfamily of meters does not meet the Company's standards for measurement tolerance. If the Company does receive compensation from a warranty claim, please discuss whether and how the Company returns these monies to ratepayers.

Response:

NW Natural has a 15-year warranty from the three major diaphragm meter manufacturers that provide meters covered under the Company's Meter Sampling Program. These manufacturers are Honeywell (previously known as Elster or American Meter), Itron and Sensus (previously known as Rockwell). If a meter family is determined non-conforming and is within the 15-year warranty period, a warranty claim is pursued for those meters. The claim threshold defined by each warranty specifies that no less than 85% of each shipment shall maintain their original factory setpoint calibration plus or minus 2%, for a period of 15 years.

Warranty claims differ between manufacturers and claims. NW Natural has a pending warranty claim with Honeywell. For more information, please see the Company's response to UG 435 OPUC Confidential DR 301.

If the Company does receive compensation from a warranty claim, the gross plant of the affected meters will be reduced and overall rate base will be reduced. The warranty claims benefit customers by a lower return on meter investments as well as the depreciation expense (return of) those investments in the next rate case and until those meters are retired.

Docket No. UG 490

Staff/902
Dlouhy/9

NW Natural®

Rates & Regulatory Affairs

UG 490

Request for a General Rate Revision

Data Request Response

Request No.: UG 490 OPUC DR 459

Please provide an estimate of the total 2024 cost for the Lexington RNG project and the Dakota City RNG project under the three following circumstances:

a. Actual RNG offtake is equal to forecasted RNG offtake.
b. Actual RNG offtake is 20 percent higher than forecasted RNG offtake.
c. Actual RNG offtake is 20 percent lower than forecasted RNG offtake.

Response:

Please see Confidential UG 490 OPUC DR 459 Attachment 1. NW Natural can walk through these calculations with Staff at Staff's convenience.

Docket No. UG 490

Staff/902
Dlouhy/10

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 460

Please provide the expected asset life of the PCC meters that the Company intends to replace as part of the Meter Modernization Program.

Response:

Meters and meter equipment are grouped into categories of like life characteristics as is the standard practice for recovery, therefore individual life per meter asset is not tracked. The current approved and proposed depreciation rate for Meters is based on an average service life of 30 years. Some of the meters being replaced are much older than 30 years and some are not which is consistent with a mortality curve for mass property gas assets.

Docket No. UG 490

Staff/902
Dlouhy/11

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 461

Please list the dollar value of the gross plant, net plant, and accumulated depreciation of the meters that the Company plans to replace as part of the Meter Modernization Program. When responding to this data request, please break out this request by Family Year.

Response:

NW Natural met with the Staff Initiator on April 1, 2024, to clarify this request. As a result of that meeting, the Company responds as follows. There are two attachments included. UG 490 OPUC DR 461 Attachment 1 is an Excel version of an earlier provided spreadsheet of eligible PCCs by meter family year (UG 490 OPUC DR 382 Attachment 1). UG 490 OPUC DR 461 Attachment 2 is an export from PowerPlan referring to the gross plant, net plant, and accumulated depreciation as of 12/31/2023 of assets inclusive to Meter Modernization.

There are some caveats that should be noted.

For UG 490 OPUC DR 461 Attachment 1:

- Meter modernization will only be changing out residential meter sets from family years 1989 to current. All PCC's from earlier years will be changed out using our internal resources as business as usual.
- A PCC "Family Year" vs. "Purchase Year" may vary somewhat.

For UG 490 OPUC DR 461 Attachment 2:

- NW Natural uses group depreciation, so all vintage years are one asset.
- Average cost provided in column "C".
- For highlighted rows in yellow, we have not updated the quantity within the system yet.
- It reflects the years Meter Modernization will be including, along with the filter of residential meters only.

Docket No. UG 490

Staff/902
Dlouhy/12

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 462

Please state whether the Company intends to remove from rate base any amounts related to meters that were removed before the end of their useful life as part of the Meter Modernization Program.

Response:

The meters will be retired from plant in service when they are removed and replaced. Based on expected mortality dispersion for all mass property accounts there are many assets that are expected to be replaced before the average and some after the average which is the case for meters. Therefore, rate base is recovered consistent with the mortality life cycle not just a useful life. However, any remaining rate base that may exist will be recovered over the remaining life of the surviving assets which is consistent with group depreciation.

CASE: UG 490
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 903

Other Documents in Support
Of Opening Testimony

April 18, 2024

COM/CR6/nd3 **Date of Issuance 9/20/2022**

Decision 22-09-026 September 15, 2022

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Building Decarbonization.	Rulemaking 19-01-011

PHASE III DECISION ELIMINATING GAS LINE EXTENSION ALLOWANCES, TEN-YEAR REFUNDABLE PAYMENT OPTION, AND FIFTY PERCENT DISCOUNT PAYMENT OPTION UNDER GAS LINE EXTENSION RULES

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PHASE III DECISION ELIMINATING GAS LINE EXTENSION ALLOWANCES, TEN-YEAR REFUNDABLE PAYMENT OPTION, AND FIFTY PERCENT DISCOUNT PAYMENT OPTION UNDER GAS LINE EXTENSION RULES

Summary

This decision adopts Energy Division's staff proposal to eliminate gas line extension allowances, the 10-year refundable payment option, and the 50 percent discount payment option provided under the current gas line extension rules. The elimination is for all customers in all customer classes effective July 1, 2023. This decision applies to new applications for gas line extensions submitted on or after July 1, 2023. Applications submitted before July 1, 2023 will not be affected by this decision.

These changes move the state closer to meeting its goals of reducing greenhouse gas (GHG)[1] emissions and combating climate change. The result will not only be significant reductions in GHG emissions but also improved quality of life and health for customers, hundreds of millions of dollars in ratepayer savings annually, greater equity for low-income customers, and greater certainty for builders, developers, and individual customers. This decision meets the statutory requirements as set forth in Public Utilities Code Section 783(b)-(d).

This proceeding remains open.

1. Procedural Background

1.1. Senate Bill (SB) 1477

On September 13, 2018, Governor Jerry Brown signed into law SB 1477 (Stern, 2018).[2] SB 1477 promotes California's building-related greenhouse gas (GHG) emission reduction goals, and makes available $50 million annually for

[1] *See* Appendix A for a list of abbreviations, acronyms, and definitions used in this decision.

[2] SB 1477 was codified as Public Utilities (Pub. Util.) Code Section 748.6, Section 910.4, and Sections 921-922.

four years,[3] for a total of $200 million, dedicated towards two building electrification pilot programs. The funds are derived from the revenue generated from the GHG emission allowances directly allocated to gas corporations and consigned to auction as part of the California Air Resources Board's (CARB) Cap-and-Trade program.[4]

On January 31, 2019, in response to the passage of SB 1477, the California Public Utilities Commission (Commission) initiated this rulemaking to support the decarbonization of buildings in California. The proceeding is:

> designed to be inclusive of any alternatives that could lead to the reduction of greenhouse gas emissions associated with energy use in buildings [related]… to the State's goals of reducing economy-wide GHG emissions 40% below 1990 levels by 2030 and achieving carbon neutrality by 2045 or sooner.[5]

1.2. Phase I

On May 17, 2019, the assigned Commissioner issued a Scoping Memo and Ruling setting forth the issues to be considered in Phase I of the proceeding (Phase I Scoping Memo). The Phase I Scoping Memo was amended on July 16, 2019 to include additional issues. Phase I was resolved in Decision (D.) 20-03-027, which established the two building decarbonization pilot programs required by SB 1477: the Building Initiative for Low-Emissions

[3] Fiscal Year (FY) 2019-2020 to FY 2022-23.

[4] Four gas corporations currently participate in California's Cap-and-Trade program: Southern California Gas Company (SoCalGas), Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southwest Gas Corporation (SWG).

[5] Order Instituting Rulemaking (OIR) 19-01-011 at 2.

Development (BUILD) Program and the Technology and Equipment for Clean Heating (TECH) Initiative.[6]

1.3. Phase II

On August 25, 2020, the assigned Commissioner issued an Amended Scoping Memo and Ruling setting forth the issues to be considered in Phase II of this proceeding and included an associated Energy Division Staff Proposal. Phase II was resolved in D.21-11-002, which: (1) adopted guiding principles for the layering of incentives when multiple programs fund the same equipment; (2) established a new Wildfire and Natural Disaster Resiliency Rebuild (WNDRR) program to provide financial incentives to help victims of wildfires and natural disasters rebuild all-electric properties; (3) provided guidance on data sharing; and (4) directed California's three large electric investor-owned utilities (IOUs)[7] to each study energy bill impacts that result from switching from gas water heaters to electric heat pump water heaters, and to propose a rate adjustment in a new Rate Design Window application if their study reflected a net energy bill increase. D.21-11-002 also directed the IOUs to collect data on fuels used to power various appliances, including propane.

1.4. Phase III

On November 16, 2021, the assigned Commissioner issued an Amended Scoping Memo and Ruling setting forth the issues to be considered in Phase III of this proceeding (Phase III Scoping Memo). Appended to the Phase III Scoping Memo were an Energy Division Staff Proposal (Phase III Staff Proposal or Staff Proposal) and a list of questions to be addressed by respondents and parties. Specifically, Phase III considers eliminating gas line extension allowances

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[6] *See* D.20-03-027 at 7.

[7] Southern California Edison Company (SCE), PG&E, and SDG&E.

(allowances), the 10-year refundable payment option (refunds), and the 50 percent discount payment option (discounts) (collectively, gas line subsidies) provided under the current gas line extension rules (gas rules).[8]

The Phase III Scoping Memo set a schedule for the filing and service of comments and reply comments on the Staff Proposal. It also required that comments and reply comments be verified.[9] Verification enables the creation of a robust and reliable record, and allows the Commission to find facts based on those pleadings. It also set a deadline by which parties could file a motion to request evidentiary hearings to cross-examine parties on disputed issues of material fact stated in comments or reply comments, or to seek leave to serve prepared testimony, which in turn might be subject to cross-examination.

Lastly, in compliance with Pub. Util. Code Section 783(c),[10] the Phase III Scoping Memo requested assistance and input from the following state agencies

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[8] Gas Rules 15-16 for PG&E (https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS_RULES_15.pdf, https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS_RULES_16.pdf), SDG&E (https://tariff.sdge.com/tm2/pdf/GAS_GAS-RULES_GRULE15.pdf, https://tariff.sdge.com/tm2/pdf/GAS_GAS-RULES_GRULE16.pdf), and SWG (https://www.swgas.com/1409184638489/rule15.pdf, https://www.swgas.com/1409184638517/RULE_16--GRC_Eff-April-1-2021.pdf), and Gas Rules 20-21 for SoCalGas (https://tariff.socalgas.com/regulatory/tariffs/tm2/pdf/20.pdf, https://tariff.socalgas.com/regulatory/tariffs/tm2/pdf/21.pdf). Rule 15/20 pertains to gas distribution main extensions and Rule 16/21 pertains to gas service line extensions.

[9] *See* Rule 1.11 and Rule 18.1. Verification requires that the person filing the pleading knows that the statements in the document are true, except for matters which are stated on information or belief, and as to those matters requires that the person believes them to be true. Moreover, it requires that the person declare under penalty of perjury that the foregoing is true and correct. The Phase III Scoping Memo stated that unverified comments and reply comments would only be given the weight of argument.

[10] Pub. Util. Code Section 783(c) states: "The commission shall request the assistance of appropriate state agencies and departments in conducting any investigation or proceeding pursuant to subdivision (b), including, but not limited to, the Transportation Agency, the

Footnote continued on next page.

and departments: the California State Transportation Agency; the California Department of Food and Agriculture; the California Department of Consumer Affairs (DCA); the California Department of Real Estate (DRE); and the California Department of Housing and Community Development (HCD).[11] On November 17, 2021, the assigned Commissioner sent a follow up e-mail to the Executive Directors (or an equivalent position) of these agencies and departments and invited them to provide input on the Staff Proposal by December 20, 2021.

Verified comments and verified reply comments on the Staff Proposal were filed on December 20, 2021, and January 10, 2022, respectively, by 18 parties: PG&E, SDG&E, and SoCalGas (collectively, the Joint IOUs); SCE; SWG; the Public Advocates Office of the California Public Utilities Commission (Cal Advocates); Clean Energy; Coalition of California Utility Employees (CCUE); California Environmental Justice Alliance (CEJA), Environmental Defense Fund (EDF), Natural Resources Defense Council (NRDC), and Sierra Club (collectively, the Joint Parties); East Bay Community Energy (EBCE), Marin Clean Energy (MCE), Sonoma Clean Power (SCP), and Peninsula Clean Energy (PCE) (collectively, the Joint CCAs); The Utility Reform Network (TURN); and Small Business Utility Advocates (SBUA).[12] No comments or responses from the state agencies and state departments were received.

Department of Food and Agriculture, the Department of Consumer Affairs, the Bureau of Real Estate, and the Department of Housing and Community Development."

[11] Phase III Scoping Memo at 1 and 12.

[12] The parties filed individual pleadings in several instances and are cited as such in this order. The exception is when they filed jointly and are cited herein as Joint IOUs, Joint Parties, or Joint CCAs.

On January 28, 2022, the assigned Administrative Law Judges (ALJs) issued a ruling seeking clarifications and additional information to assist the Commission in resolving the Phase III issues. On February 21, 2022, comments were filed by Cal Advocates, Clean Energy, SBUA, the Joint Parties, PG&E, SWG, SDG&E and SoCalGas.

On March 22, 2022, the assigned ALJs issued a ruling revising the remaining proceeding schedule and addressing other procedural matters. Specifically, the ruling informed parties of a March 14, 2022, Energy Division data request (ED-DR) sent to PG&E, SoCalGas, SDG&E and SWG; directed the gas utilities to verify and serve their responses to the ED-DR on all parties; provided an opportunity for parties to comment on the gas utilities' responses to the ED-DR; and updated the schedule for the remainder of the proceeding. On April 4, 2022, the gas utilities verified and served their responses to the ED-DR. On April 11, 2022, Clean Energy filed comments on the gas utilities' responses to the ED-DR. On April 18, 2022, the assigned ALJs issued a ruling receiving into the evidentiary record the gas utilities' responses to the ED-DR (April 18, 2022 ALJ Ruling).

No motion was made for evidentiary hearing. No evidentiary hearing was held.

On May 4, 2022, opening briefs were filed and served by PG&E, SoCalGas, SDG&E, Cal Advocates, Clean Energy, the Joint Parties, TURN, and SBUA. On May 18, 2022, reply briefs were filed and served by PG&E, SoCalGas, SDG&E, Clean Energy, the Joint Parties, TURN, and SBUA. The record is the Staff Proposal; comments and reply comments; the gas IOUs' responses to the ED-DR; and parties' briefs. Phase III was submitted for decision on May 18, 2022 (upon receipt of reply briefs).

2. Issues Before the Commission

The Phase III Scoping Memo identified the following issues to be resolved:[13]

A. Whether the Commission should modify or eliminate gas line extension allowances for some or all customer classes (residential and non-residential);

B. Whether the Commission should modify or eliminate gas line extension refunds for some or all customer classes (residential and non-residential); and

C. Whether the Commission should modify or eliminate gas line extension discounts for some or all customer classes (residential and non-residential).

This decision addresses all the issues identified in the Phase III Scoping Memo and concludes Phase III of the proceeding. The proceeding remains open to consider additional building decarbonization issues in future phases.

3. Gas Line Subsidies

3.1. History of Gas Line Subsidies

The history of the gas rules in California dates back more than a century. With Commission decisions beginning in 1915 and continuing to today, California's gas IOUs have an obligation to provide prospective new customers the opportunity to receive utility service via a line extension based on a uniform set of rules. Under current rules, gas IOUs are not obligated to extend gas lines free of cost but must provide the opportunity for customers to be connected to the utility system at reasonable prices, terms, and conditions.

In general, applicants for new service must pay the full cost of the line extension and interconnection but are provided offsets for part of the cost. These offsets, or subsidies, were reasonable when utilities were in a declining cost

[13] Phase III Scoping Memo at 3-5.

industry, in which the addition of more customers led to reductions in the utility's costs and rates, thereby benefiting both old and new customers.

Conditions in the 1970s led the Commission to reconsider these gas line subsidies. These conditions included severe economic and energy challenges such as oil and natural gas embargos, shortages, and significant price increases; increasing cost and environmental concerns from the continued use, and new development of conventional thermal electric generating resources (including oil, gas, coal, and nuclear); inflation; economic stagnation; and repeated gas and electric utility cost and rate increases. In 1974, the Legislature requested that the Commission investigate electric rate structures and consider alternatives that would discourage, rather than encourage, increased energy consumption.

In 1977, the Commission opened an investigation to reconsider line extension rules given these fundamental changes.[14] Among the considerations was whether existing allowances for extensions of gas and electric service should be modified or abolished. Several decisions followed.

In D.91328, the Commission decided to abolish gas and electric line allowances, terminate refunds, and provide incentives for conservation.[15] On rehearing, the Commission decided to phase out line extension allowances over about five years, and established June 1, 1983, for the filing of utility tariffs to begin the phase-out.[16]

The legislature responded to the Commission's decisions ending and phasing out line extension allowances by passing an urgency bill to add

[14] Case 10260.

[15] D.91328, February 13, 1980.

[16] D.82-04-068, April 1982 and D.82-12-094, December 1982.

Pub. Util. Code Section 783.[17] The new law requires that the Commission continue the line extension rules that were in place on January 1, 1982, and not make any changes (with limited exceptions) unless the Commission made findings on each of seven issues set out in Pub. Util. Code Section 783. Shortly thereafter, the Commission rescinded all prior orders and closed its investigation into line extension rules.[18]

Further consideration of modifying or eliminating gas line subsidies is governed by Pub. Util. Code Section 783(b), which states that whenever the Commission:

> …institutes an investigation into the terms and conditions for the extension of services provided by gas and electrical corporations to new or existing customers, or considers issuing an order or decision amending those terms or conditions, the commission shall make written findings on all of the following [seven] issues.

In summary, the seven issues include an examination of the economic and other effects of line and service extension modifications upon residential and non-residential customers (*e.g.*, agricultural, commercial, industrial), locally funded governmental or district projects, redevelopment projects, existing ratepayers, energy consumption, and energy conservation.

Pub. Util. Code Section 783(c) requires that:

> The commission shall request the assistance of appropriate state agencies and departments in conducting any investigation or proceeding pursuant to subdivision (b), including, but not limited to, the Transportation Agency, the Department of Food and Agriculture, the Department of

[17] SB 48; Stats. 1983, Ch. 1229, Sec. 2, effective September 30, 1983.

[18] D.83-09-066, D.84-04-047.

> Consumer Affairs, the Bureau of Real Estate, and the Department of Housing and Community Development.
>
> Lastly, Pub. Util. Code Section 783(d) requires that:
>
> Any new order or decision issued pursuant to an investigation or proceeding conducted pursuant to subdivision (b) shall become effective on July 1 of the year which follows the year when the new order or decision is adopted by the commission, so as to ensure that the public has at least six months to consider the new order or decision.[19]

This ensures that the public has at least six months to consider the new order or decision.

3.2. Line Extension Costs and Subsidies

Under current gas rules, the total cost of a gas line extension for an entity (*e.g.*, builder, developer, individual customer) who seeks connection to the utility system (applicant) is paid by the applicant at project commencement. The total project cost is divided into two parts: non-refundable and refundable.[20] Both the non-refundable and refundable parts are paid by the applicant, but the refundable costs are offset or subsidized by all other ratepayers. Refundable costs are first subsidized by "allowances." Refundable costs in excess of allowances, if any, are returned to an applicant via either: (1) refunds over 10 years; or

---

[19] *See* https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=783&lawCode=PUC.

[20] Both "refundable" costs and "non-refundable" costs are specified in Section D.6 of Gas Rule 15 for PG&E, SDG&E, and SWG and Gas Rule 20 for SoCalGas. Per Section D.6.a of Gas Rule 15/20, refundable costs include the total estimated installed cost, including taxes, to complete the distribution line extension. Per Section D.6.c of Gas Rule 15/20, non-refundable costs include the estimated value of all substructures and other protective structures. Section E.5 of Gas Rule 16 for PG&E, SDG&E, and SWG, and Gas Rule 21 for SoCalGas specifies that service line extensions are not eligible for refund.

(2) a one-time 50 percent discount at the option of the applicant. These three gas line subsidies are further described below.

3.2.1. Allowances

For residential customers, allowances are fixed amounts awarded by appliance per residential unit. Each gas utility has different allowance levels. The table below has the current allowances.

Table 1. Current Residential Gas Line Extension Allowances
(Per Meter or Residential Dwelling Unit, on a per unit basis)

Item	PG&E[21]	SCG[22]	SDG&E[23]	SWG[24]	
				Southern California	Northern California / South Lake Tahoe
Water Heating	$1,391	$1,138	$643	$183	$231
Space Heating	$987	$987	$698	$674	$862
Oven/Range	$84	$201	$114	$69	$28
Dryer Stub	$24	$289	$160	$115	$70
Space Cooling	NA	NA	$1,098	$1,765	NA

For non-residential customers, allowances are provided by a formula that is calculated on a site-specific basis taking into consideration usage, demand, and

[21] PG&E rates effective January 1, 2022 (https://www.pge.com/tariffs/assets/pdf/adviceletter/GAS_4488-G.pdf).

[22] SCG Rule 20 Gas Rules approved in 2022 (https://tariff.socalgas.com/regulatory/tariffs/tm2/pdf/20.pdf).

[23] SDG&E rates approved in 2020 (https://tariff.sdge.com/tm2/pdf/2866-G.pdf).

[24] SWG rates are bifurcated into their two non-contiguous territories (https://www.swgas.com/1409184638489/rule15.pdf).

other factors. The allowance value is equal to "net revenue"[25] divided by "cost of service factor."[26]

In 2021, three of the four California large gas IOUs spent over $104 million on allowances ($81 million on residential allowances and $23 million on non-residential allowances).[27] We note that this amount does not include SDG&E's allowance expenditures.[28] Therefore, if SDG&E's allowance expenditures were to be included, the total amount would be higher.

3.2.2. Refunds

Under the refund option, the gas IOU returns remaining refundable costs (*i.e.*, those that remain after application of allowances) to the applicant over the course of 10 years. Adjustments are made if further development occurs, and new customers are added that utilize the same newly constructed segment of the gas distribution line to fairly allocate common costs.

In 2021, California's four large gas IOUs spent approximately $2.9 million on refunds ($1.5 million in residential refunds and $1.4 million in non-residential refunds).[29] We note that this amount does not include all of SDG&E's refunds

[25] "Net revenue" is a projection of how much additional revenue a gas IOU is expected to net annually as a result of a new customer using gas.

[26] "Cost of service factor" is a figure that represents the annual cost of servicing one dollar's worth of capital investment for which ratepayers must pay.

[27] The three IOUs are PG&E, SoCalGas, and SWG. The data does not include SDG&E's allowances because SDG&E says that information is not available due to the limitation of SDG&E's project management system. (April 18, 2022 ALJ Ruling, Attachment 3 and Attachment 5.)

[28] SDG&E did not provide data on allowances to the Commission. In explanation, SDG&E says its project management system does not facilitate data extraction of allowances granted or discounts provided. (*See* April 18, 2022 ALJ Ruling, Attachment 3 at 1.)

[29] April 18, 2022 ALJ Ruling, Attachment 5.

expenditures.[30] Therefore, if all of SDG&E's refund expenditures were to be included, the total amount would likely be higher.

3.2.3. Discounts

The discount payment option is an alternative to the refund option. If the applicant selects the discount option over the refund option, they receive a one-time 50 percent discount on the refundable costs that remain after application of available allowances. The discount is received at the time payments are due and the applicant does not need to wait for refunds over several years.

In 2021, three of four California large gas IOUs spent approximately $23.4 million on discounts ($17.7 million in residential discounts, and $5.7 million in non-residential discounts).[31] We note that this amount does not include SDG&E's discount expenditures.[32] Therefore, if SDG&E's discount expenditures were to be included, the total amount would be higher.

3.2.4. Total Subsidies

Over the last five years (2017 to 2021), California's four gas IOUs (with partial data for SDG&E) spent approximately $622 million (approximately $124 million annually) on gas line subsidies, including allowances, refunds and

[30] SDG&E refund data includes residential and commercial, but not other non-residential (*e.g.*, industrial, agricultural). (April 18, 2022 ALJ Ruling, Attachment 3 at 1.)

[31] The data does not include SDG&E's discounts because the information is not available due to the limitation of SDG&E's project management system. (*See* April 18, 2022 ALJ Ruling, Attachment 3 and Attachment 5.)

[32] SDG&E did not provide data on discounts to the Commission. In explanation, SDG&E says its project management system does not facilitate data extraction of allowances granted or discounts provided." (*See* April 18, 2022 ALJ Ruling, Attachment 3 at 1.)

discounts.[33] Over the next five years (2022 to 2026) if gas line subsidies continue, the gas IOUs (with partial data for SDG&E) anticipate they will spend approximately $819 million (approximately $164 million annually) on gas line subsidies.[34] The gas IOUs' data shows that this totals more than $1.4 billion over the 10-year period from 2017-2026 (about $144 million annually). The table below provides each of the gas IOUs' historical (2017-2021) and forecasted total gas line subsidies (2022-2026).[35]

Table 2. 2017-2026 Historical and Forecasted Total Gas Line Subsidies ($ million)[36]

IOUs	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total (2017–2026)
PG&E	$44	$57	$75	$88	$69	$101	$106	$105	$101	$97	$843
SoCalGas	$48	$55	$51	$51	$57	$57	$57	$58	$58	$58	$550
SDG&E[37]	$1	$2	$2	$2	$1	$1	$1	$1	$1	$1	$13
SWG	$4	$3	$7	$3	$3	$3	$3	$3	$3	$3	$35
Total	**$97**	**$117**	**$135**	**$143**	**$130**	**$162**	**$168**	**$167**	**$163**	**$160**	**$1,441**

Once the gas line extensions are built, the gas IOUs own and operate the facilities as a part of their systems. The IOUs recover the expended gas line subsidies as capital costs through their ratebase, subject to depreciation and rates of return over the depreciable life (*e.g.*, 30 years) of the line extensions. As a

[33] The total amount includes SDG&E's amounts for refunds but not for allowances and discounts because the information is not available due to the limitation of SDG&E's project management system. (*See* April 18, 2022 ALJ Ruling, Attachment 3 and Attachment 5.)

[34] April 18, 2022 ALJ Ruling, Attachment 5.

[35] *Id.*

[36] *Id.*

[37] Only partial data for SDG&E.

result, the total amounts paid by ratepayers (revenue requirements) associated with the 2017-2026 total gas line subsidies would be well above the $1.4 billion.

4. Energy Division Staff Proposal

The Staff Proposal recommends eliminating the gas line subsidies for all customer classes. Staff argues that California's gas line subsidies are designed to encourage gas usage, as affirmed in both D.89177 and D.91328, and that by allowing builders to receive a separate allowance for each approved appliance type, builders are incentivized to install more gas appliances in order to defray more costs. Those gas appliances, in turn, perpetuate reliance on gas service and lock in all associated GHG emissions for the life of the appliance, which averages 10 to 20 years for a gas water heater and 18 years for a gas furnace unless the appliance is retired early and replaced with an electric alternative. Additionally, a key strategy to reach carbon neutrality by 2045 is to phase out gas usage in the building sector. Any new gas infrastructure is likely to become a stranded asset. The maintenance and operational costs associated with gas infrastructure will need to be paid for by a shrinking number of future gas customers, which will be reflected in higher rates. These customers are likely to be low-income customers as they face the greatest barriers to electrification, including affordability challenges presented by the upfront costs of electrification. As such, the provision of gas line allowances makes it harder to meet California's GHG reduction goals while increasing the future cost of gas service for customers that are unwilling or unable to switch from gas to electric service.[38] The Staff Proposal provides further details on the following benefits in support of eliminating gas line subsidies for all customer classes.

[38] Staff Proposal. (*See* Phase III Scoping Memo, Appendix A at 24-25.)

4.1. Lowers Gas Consumption and GHG Emissions

The Staff Proposal states that since these subsidies promote the increased and continued use of gas, they perpetuate reliance on gas service and lock in all associated GHG emissions for the life of the appliance unless the appliance is retired early and replaced with an electric alternative. Staff argues that the elimination of these subsidies would result in less gas consumption, more electricity consumption, fewer GHG emissions and less air pollution.[39]

4.2. Results in Ratepayer Savings

According to data submitted by the gas IOUs, and served in response to the March 22, 2022 Assigned ALJs' Ruling, the total amount of subsidies provided across all four gas IOU territories (partial data for SDG&E)[40] in 2021 was approximately $130 million. The IOUs project this to increase in coming years, peaking at $168 million in 2023.[41] Because of data deficiencies from SDG&E, these reported aggregated numbers are undoubtedly lower than the actual subsidies being paid. Additionally, the Staff Proposal states that if a new dual fuel building were to be constructed without gas line subsidies, gas ratepayers would save even more as a result of an additional customer sharing in costs necessary to maintain the common carrier pipeline network, so eliminating the line extension subsidies would save ratepayers hundreds of millions of dollars. Although it is noted that these savings could be used for a multitude of useful purposes, the Staff Proposal does not at this time make any

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[39] Staff Proposal. (*See* Phase III Scoping Memo, Appendix A at 35, 40, and 44.)

[40] The total amount excludes SDG&E's amounts for allowances and discounts because the information is not available due to the limitation of SDG&E's project management system. (*See* April 18, 2022 ALJ Ruling, Attachment 3 and Attachment 5.)

[41] April 18, 2022 ALJ Ruling, Attachment 2 and Attachment 5 at 2.

recommendations on diverting funds for other purposes, but instead highlights that cost savings make other investments possible without causing upward rate pressure.[42] Eliminating gas line subsidies for all new constructions would result in the following estimated minimum savings below.

Table 3. Estimated Annual Savings to Gas Ratepayers from Eliminating Residential Gas Line Subsidies ($ million)

Gas Line Subsidies	**2021 Expenditures**[43]					**Estimated Annual Savings**[44] **(Average of Forecast 2024-2026)**				
	PG&E	**SoCalGas**	**SDG&E**	**SWG**	**Total**	**PG&E**	**SoCalGas**	**SDG&E**	**SWG**	**Total**
Allowances	$39	$40	Did not provide	$2	$81	$47	$41	Did not provide	$2	$90
Refunds	$0.4	$0.1	$1	$.07	$1.57	$.5	$0	$1	$0	$1.5
Discounts	$15	$2	Did not provide	$0.5	$17.5	$18	$2	Did not provide	$0	$20
Total	**$54.4**	**$42**	**$1**	**$2.57**	**$100.07**	**$65.5**	**$42**	**$1**	**$2**	**$110.5**

[42] Staff Proposal. *See* Phase III Scoping Memo, Appendix A at 46.

[43] April 18, 2022 ALJ Ruling, Attachment 5.

[44] April 18, 2022 ALJ Ruling, Attachments 1-5. Estimates are averages provided by the IOUs of projected expenditures from 2024 to 2026. Year 2024 is the first full year that this decision would be in effect.

Table 4. Estimated Annual Savings to Gas Ratepayers from Eliminating Non-Residential Gas Line Subsidies ($ million)

Gas Line Subsidies	2021 Expenditures[45]					Estimated Annual Savings[46] (Average of Forecast 2024-2026)				
	PG&E	SoCalGas	SDG&E	SWG	Total	PG&E	SoCalGas	SDG&E	SWG	Total
Allowances	$8	$14	Did not provide	$1	$23	$13	$14	Did not provide	$1	$28
Refunds	$0.3	$0	$0[47]	$0	$0.3	$1	$0	$0	$0	$1
Discounts	$6	$0	Did not provide	$0	$6	$20	$0	Did not provide	$0	$20
Total	**$14.3**	**$14**	**$0**	**$1**	**$29.3**	**$36**	**$14**	**$0**	**$1**	**$49**

4.3. Places the Financial Responsibility on the Initiating Party

The Staff Proposal argues that eliminating gas line subsidies will force builders, or customers, to shoulder a greater portion of the expenses associated with gas line extensions if they choose to construct a building that uses gas or extends gas service on existing properties. That greater expense, in turn, would be passed on at the point of sale for a new building or directly absorbed by the customer for an existing building. This added up-front cost burden would send a signal to builders that building new gas infrastructure is more expensive, and thus make dual fuel new construction less desirable and more costly. As such, the builder community would be more likely to gravitate toward all-electric new construction. The Staff Proposal further notes that property price increases for

[45] April 18, 2022 ALJ Ruling, Attachment 5.

[46] Estimate based on IOU projections reported to CPUC and served as attachment in the April 18, 2022 ALJ Ruling. Figures are 2024 projections as that is the first full year that this decision would be in effect.

[47] Commercial only.

dual fuel new construction would become moot if all new homes and offices are built all-electric.[48]

4.4. Incentivizes New All-Electric Construction

The Staff Proposal argues that eliminating the gas line subsidies for all new construction would increase the number of newly constructed all-electric buildings which will likely cost less than newly constructed dual fuel buildings. Dual fuel buildings constructed without gas line extension allowances would be expected to cost more than they do today, but not by more than approximately 0.25 percent on average.[49] The Staff Proposal also notes that specifically eliminating refunds would remove additional incentives for builders to encourage even more dual fuel construction in the future. Because refund payments are contingent on additional dual fuel buildings being added to a newly constructed gas line extension, builders have a strong interest in adding more dual fuel homes in the vicinity of their dual fuel construction projects. Eliminating refunds removes such considerations and motivations for the builder.[50]

4.5. Provides Certainty to Builder Community for Future Projects and Planning

The Staff Proposal states that eliminating refunds has the additional benefit of encouraging a more predictable future for the building industry. California is already on a trajectory toward building decarbonization, which will eventually result in builders receiving less in refund payments as a greater percentage of homes and offices are built all-electric moving forward. Rather

[48] Phase III Scoping Memo, Appendix A at 31.

[49] Phase III Scoping Memo, Appendix A at 33-34 and 41.

[50] Phase III Scoping Memo, Appendix A at 36.

than have builders speculate as to whether they will ever be refunded their full advance payments for building gas infrastructure, eliminating refunds on a set date lets builders know from what point forward their refund payments will stop, thus enabling the builder community to build that knowledge into their project financing considerations and future revenue assumptions.[51]

4.6. Minimally Impacts Property Prices

The Staff Proposal argues that eliminating the gas line subsidies is not expected to lead to a significant rise in average property prices. To the extent that such a policy change leads to more all-electric new construction, those new homes and offices will be less expensive than if they were built dual fuel due to the elimination of any expense associated with installing gas infrastructure (*e.g.*, trenches, pipes, meters). If a builder opts to still build dual fuel, any resulting property price increase should be minimal.[52] If allowances are eliminated, residential property prices would increase between 0.21-0.25 percent,[53] and non-residential property prices would increase by 0.25 percent.[54] If refunds are eliminated, residential and non-residential property prices are estimated to increase by 0.07 percent.[55] If discounts are eliminated, residential and non-residential property prices are estimated to increase by 0.04 percent.[56] The combined effect of eliminating all subsidies (allowances,

[51] Phase III Scoping Memo, Appendix A at 37.

[52] Phase III Scoping Memo, Appendix A at 31-32.

[53] Phase III Scoping Memo, Appendix A at 32-33.

[54] Phase III Scoping Memo, Appendix A at 33.

[55] Phase III Scoping Memo, Appendix A at 32 and 37-38.

[56] Phase III Scoping Memo, Appendix A at 32 and 41-42.

refunds, and discounts) is 0.32-0.36 percent for residential and non-residential properties.[57]

5. Residential Gas Line Subsidies Revisions

Of the 18 parties commenting on eliminating the gas line subsidies for residential customers, 16 parties endorse the Staff Proposal (or suggest phased elimination) and two oppose.

5.1. Positions of Parties Supporting the Staff Proposal

The 16 parties who endorse the Staff Proposal to eliminate gas line subsidies for the residential sector (or who suggest phased elimination) are: PG&E, SDG&E, SCE, Clean Energy, Cal Advocates, CEJA, EDF, NRDC, Sierra Club, TURN, EBCE, MCE, SCP, PCE, and SBUA. SoCalGas did not oppose the recommendation on residential gas line extension allowances, refunds, and discounts as a policy matter. Parties supporting the Staff Proposal make several points.

- Elimination of the gas line subsidies will discourage construction of gas infrastructure while encouraging more all-electric new construction that together will help reduce GHG emissions and improve air quality consistent with California's decarbonization goals;
- Current gas line subsidies provide incentives to install appliances which largely lock-in that use over the 10 to 20-year life of the appliance, which are likely to become

[57] Non-residential property price impacts can be estimated based on the same logic used to estimate residential property price impacts. D.07-07-019 did not make any finding of fact regarding the property price impact associated with the elimination of line extension allowances for non-residential building, but the inputs and assumptions used to determine non-residential allowances (*e.g.*, demand, usage, *etc.*) are largely the same as for residential allowance computations. (Phase III Scoping Memo, Appendix A at 32.)

stranded assets given California's ambitious GHG emissions reduction goals;

- Elimination of gas line subsidies does not prohibit any customer from installing gas appliances in applications that need, or where the customer prefers, to use gas, but it relieves other gas ratepayers from subsidizing the extension for those customers and reduces average gas rates for all gas customers;
- Gas line subsidies originated when interconnecting more customers was thought to lower costs and benefit all; this is no longer the case and the benefits, if any, no longer outweigh the costs of increased GHG emissions and dependence on combustion fuels;
- The elimination of gas line subsidies will save ratepayers hundreds of millions of dollars; support equitable transition from gas to electricity; further California's climate goals; improve air quality and related health outcomes both inside and outside buildings; and provide greater certainty to builders, contractors, and gas distribution workers. Eliminating gas line subsidies is of particular benefit to low-income customers given these financial implications;
- Existing gas line subsidies work against the goals of multiple Commission-authorized building decarbonization programs also funded by ratepayers;
- There will be minimal or no overall negative impacts on workers, with the increased number of jobs in the electric industry being the same or more than the decrease of jobs in the gas industry;
- There will be minimal or no overall negative impacts on low-income customers, as programs such as BUILD, the California Energy Smart Homes Program, and discount rate programs such as the California Alternative Rates for Energy and Family Electric Rate Assistance help mitigate such upfront effects on the affordable housing and low-income sectors. Given their lower rate of new home

purchasing, low-income customers are not typically the ones benefitting from gas line subsidies, yet they contribute towards these subsidies which inequitably increases gas rates for all customers, including low-income customers;

- There will be minimal impacts on property prices, as all-electric new homes are less expensive to build than dual fuel homes. Additionally, programs such as the California Electric Homes Program will provide $75 million in financial incentives and technical support for the construction of new all-electric residential buildings;
- The Commission should consider changes to gas line extension rules in the broader context of California's climate change policy and consult with other state agencies;
- The Joint IOUs recommend a phased elimination to reduce the immediate negative impacts while still accomplishing the overall objectives in support of California's climate goals. In particular, they state that a phased approach would:[58]
    - Avoid near-term gas rate increases if the proposed changes substantially reduce the number of new connections relative to forecasts used in approved ratemaking proceedings;
    - Allow recognition of the varying schedules for future ratemaking proceedings;
    - Allow time for customers to account for increased project costs; and
    - Allow utilities time to study the impact on their electric load profiles and generation needs.

[58] Opening Comments of the Joint IOUs on Phase III Staff Proposal at 9-10.

5.2. Positions of Parties Opposing the Staff Proposal

The two parties who oppose the Staff Proposal in their comments are SWG and CCUE. They make several points in opposition.

- Gas line subsidies allow new customers access to clean, reliable, and affordable fuel (*e.g.*, renewable natural gas, hydrogen) that is poised to contribute significantly to decarbonization efforts;
- Fuel choice should be left to the customer and decisions to reduce GHG emissions should be energy commodity neutral;
- Natural gas systems can decarbonize and play an important role in meeting California's energy objectives;
- Prices for dual fuel homes will increase and prices for all-electric homes will decrease, requiring builders to charge more to offset the loss of the gas line subsidies where natural gas remains in demand (*e.g.*, cold climates);
- Gas rates will increase as fixed costs of the gas system will be spread over a declining customer base, leaving those who cannot afford to electrify or don't have the option to electrify, with higher gas rates;
- Gas industry workers will be negatively impacted, with fewer workers to safely operate and maintain the gas system, safely and properly decommission gas infrastructure, and install new technology, affecting safety and reliability;
- Grid reliability will be negatively impacted as California's supply of gas-fired generation decreases while the need for flexible, fast ramping generation and local reliability remains; and
- A decision in this proceeding should be delayed until Rulemaking (R.) 20-01-007 concludes because both proceedings address similar forward-looking gas infrastructure issues, and delineating the future of natural gas in California is a necessary threshold issue.

5.3. Discussion

5.3.1. Elimination of Gas Line Subsidies for Residential Customers: Approved

This decision adopts the staff's proposal to eliminate the residential gas line subsidies effective July 1, 2023. The elimination of subsidies applies to new applications for gas line extensions submitted on or after July 1, 2023, and will not affect applications submitted to the IOUs before July 1, 2023. Within 30 days of the date of this order, the gas IOUs shall each submit a Tier 2 Advice Letter (AL) to revise their respective gas rules to implement this decision.

We make this revision to the gas rules because it is consistent with state objectives and policy framework. It will move the state closer to meeting its goals of reducing GHG emissions and combating climate change. The cumulative ratepayer savings from avoided gas line subsidies over the life of the gas line extensions will be significant.

As noted above, the total amount in rates paid by all ratepayers (*i.e.*, revenue requirements) associated with the 2017-2026 total gas line subsidies will be at least $1.4 billion. In addition to the significant reductions in GHG emissions and ratepayer savings, these changes will also improve the quality of life and health for customers, provide greater equity for low-income customers, and greater certainty for builders, developers, and individual customers. These benefits are discussed in more detail below.

The Commission also notes the broad support for the Staff Proposal to eliminate the gas line subsidies for the residential sector from a cross-section of parties representing a wide range of interests (*e.g.*, utility, ratepayer, environmental, social justice, community choice aggregators). However, we also address other party concerns in more detail below.

5.3.1.1. Elimination of Residential Gas Line Subsidies Aligns with Overall State Decarbonization Goals

The current gas line subsidies were established during a period when the state's energy needs, and policy goals were very different from today's. They are no longer consistent with today's GHG emission reduction goals, the urgent need to reduce costs and rates, and the long term need to minimize future stranded investment.

The Commission agrees with the Staff Proposal, SCE, Cal Advocates, the Joint Parties, TURN, and the Joint CCAs that the continuation of these subsidies work against today's climate goals and conflicts with SB 32 and SB 1477. As the Staff Proposal correctly points out, current gas line subsidies encourage gas use by providing incentives to builders to install more gas appliances, perpetuating a continued reliance on the gas system both now and over the life of the appliance, and offsetting if not reversing any GHG emission reduction benefits secured through other decarbonization measures.

The Commission also agrees with the Joint Parties that the elimination of the gas line subsidies is essential in complementing the changes made to the 2022 Building Code,[59] which go into effect in 2023.[60] These changes include requiring an electric heat pump space or water heater in standard building design, and electrification readiness (including appropriate electric, space, and plumbing readiness to accommodate a heat pump water heater where not initially installed). The policy would also complement CARB's proposal, laid out in its

[59] 2022 Building Efficiency Standards (https://www.energy.ca.gov/programs-and-topics/programs/building-energy-efficiency-standards/2022-building-energy-efficiency).

[60] Opening Brief of Joint Parties at 7-8.

Draft 2022 State Strategy for the State Implementation Plan,[61] to implement a zero-emissions standard for all new space and water heaters by 2030, citing the "opportunity for substantial emissions reductions where zero-emission technology is available."[62]

5.3.1.2. The Elimination of Residential Gas Line Subsidies Improves Overall Quality of Life (GHG Emissions Reductions, Ratepayer Savings, Benefits to Low Income, Greater Certainty)

The Commission also agrees with the numerous supporting parties that the elimination of these subsidies will result in significant societal and ratepayer benefits. These benefits include GHG emission reductions, with improved health conditions for customers via improved indoor and outdoor air quality, with particularly reduced health risks from the reduction of high GHG emitting appliances inside a home. Low-income customers are most likely to face these health risks given they often have less effective stove ventilation systems.[63]

Other impacts include reducing or eliminating a range of other negative environmental effects including land use impacts, wildlife impacts, and impacts on water use and water quality. Building out the natural gas system can cause erosion of minerals and toxins into nearby streams, contamination of drinking water sources, and high levels of water use.[64]

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[61] Although still a draft, this proposal indicates the direction state policy is headed. CARB, Draft 2022 State Strategy for the State Implementation Plan at 86 (https://ww2.arb.ca.gov/sites/default/files/2022-01/Draft_2022_State_SIP_Strategy.pdf).

[62] Opening Brief of Joint Parties at 8.

[63] Opening Brief of Joint Parties at 8-9.

[64] Response of the Joint Parties to the January 28, 2022 Assigned ALJs' Ruling Seeking Clarifications and Additional Information at 5.

The benefits also include hundreds of millions of dollars in utility and ratepayer savings annually and over time. For example, the costs identified by Staff are the costs that the utility must spend each year for construction and installation.[65] Those costs are financed by the utility (*e.g.*, via stocks, bonds, retained earnings) so the funds are available to complete the line extension in the year requested. Those costs are then put into ratebase to be recovered over time (*e.g.*, 30 years) from ratepayers. Thus, the Joint Parties and TURN are correct that the savings identified in the Staff Proposal are understated with respect to the actual cost to ratepayers.[66] The cost is higher since recovery over 30 years costs ratepayers more than would a one-time charge. The elimination of gas line subsidies is one of many steps in furthering the decarbonization of buildings, while easing the burden on residential customers that currently subsidize the new interconnections. This is of particular benefit to low-income customers who face increasing affordability pressures. As the Joint Parties note, the current context perpetuates inequity (*i.e.*, low-income customers are not typically the ones benefitting from gas line subsidies given their lower rate of new home purchasing, yet they contribute towards these subsidies which increase gas rates for all customers).[67]

Additionally, eliminating gas line extension incentives will offer the benefit of greater certainty for the market. This is especially true for the builder community and the contractor community, as noted in the Staff Proposal.

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[65] The customer pays the entire line extension cost upfront, but that total is offset by the subsidies (allowances, refunds, discounts). The utility must fund the subsidies to get back up to the total line extension cost.

[66] Opening Comments of Joint Parties and TURN on Phase III Staff Proposal at 6.

[67] Opening Comments of Joint Parties and TURN on Phase III Staff Proposal at 2.

Lastly, eliminating gas line extension allowances is not expected to lead to a significant rise in average property prices per the Staff Proposal. To the extent that such a policy change leads to more all-electric new construction, those new homes and offices will be less expensive than if they were built dual fuel due to the elimination of any expense associated with installing gas infrastructure. On the other hand, construction cost/property prices are likely to increase for those that build dual fuel, necessitating gas line extensions. Data provided in the Staff Proposal, however, shows this increase is limited to about 0.32 percent to 0.36 percent.[68] The Commission agrees that this is a minimal effect on the total cost of a new residential and commercial building. Thus, we find the net benefits from these eliminations to be greater than the additional costs that would be placed on to builders or experienced by owners of new buildings choosing dual-fuel construction.

5.3.1.3. The Elimination of Residential Gas Line Subsidies Benefits Low Income and Vulnerable Communities

Eliminating gas line subsidies will advance equity. This occurs given that low-income customers contribute towards these subsidies through gas rates even though they are typically not the ones applying for, or benefiting from, the gas line subsidies (due to the fact that they are more likely to be renters than homeowners). Equity is advanced by revenue requirements being reduced for

[68] Staff Proposal from ruling of November 16, 2021 at 33 (*see* Phase III Scoping Memo, Appendix A). An increase of 0.036 percent is an increase of $36 for each $100,000.

everyone, including low-income customers, estimated at approximately $164 million annually.[69]

We also note the concern with low-income and vulnerable communities not having the means to electrify, and whether or not they will be "left behind" to carry the burden of higher gas rates as other customers leave the gas system. This is at least in part addressed by current programs, including BUILD and California Energy Smart Homes, which help mitigate these effects by offering subsidies and technical assistance to build homes that are all electric and beyond the current building code. BUILD, in particular, is focused on low-income housing.[70]

Lastly, the Commission agrees with the Joint Parties that:

> …negative implications for affordable housing developers and low-income home purchasers, in terms of upfront purchasing costs, are very small if nonexistent… at least one study has found that electrification in new construction reduces costs over the lifetime of appliances when compared to new homes built with fossil-fuel burning appliances.[71]

5.3.1.4. The Elimination of Residential Gas Line Subsidies Has a Net Positive Impact on Workforce

The Commission acknowledges that as more buildings electrify, there is likely to be a shift in demand for work in both the gas and electric fields. CCUE

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[69] Over the next five years (2022 to 2026) if gas line subsidies continue, the gas IOUs (with partial data for SDG&E) anticipate they will spend approximately $819 million (approximately $164 million annually) on gas line subsidies (April 18, 2022 ALJ Ruling, Attachment 5).

[70] Program details about BUILD are available at: https://www.energy.ca.gov/programs-and-topics/programs/building-initiative-low-emissions-development-program. Program details about the California Smart Energy Homes program are available at: https://www.caenergysmarthomes.com.

[71] Opening Comments of CEJA, EDF, NRDC, Sierra Club, and TURN at 7

claims there will be a loss of more than 10,000 gas distribution jobs in California due to decarbonization,[72] while SCE claims a net gain of 7,000 full time jobs (12,400 full time electricity generation and distribution jobs offset by 5,400–6,800 fewer full-time gas distribution jobs).[73] The Commission agrees with SCE that there will likely be a net positive impact as we are likely to see an increase in demand for skilled workers in several economic sectors, including in the electric industry, construction jobs for energy efficiency improvements and building retrofits.

Additionally, since Track 2 of the Long-Term Gas Planning OIR, R.20-01-007, will be addressing the issue of ensuring an equitable future that minimizes workforce disruption, CCUE's concerns are best addressed in that proceeding. The Scoping Memo in that proceeding lays out a scope that includes how negative impacts on workforce from building decarbonization can be mitigated, what the costs of these mitigation strategies are, and who should be responsible for paying them, among other questions.[74]

5.3.1.5. The Elimination of Residential Gas Line Subsidies Maintains Customer Choice and Advances Equity

The Commission disagrees with SWG that we are removing customer choice by eliminating the gas line subsidies. We reiterate that customers can continue to select their choice of fuel. The only difference is that existing and

[72] Comments of the CCUE on Phase III Staff Proposal at 5.

[73] Comments of SCE on Phase III Amended Scoping Memo and Ruling of Assigned Commissioner at 4.

[74] OIR to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and perform Long-Term Gas System Planning, Section 2.3.2 at 7 (https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M415/K275/415275138.PDF).

future gas customers will no longer have to subsidize investments in the gas infrastructure for new customers. Requiring the new customers to pay their full costs of gas line extensions only places the responsibility back onto builders or customers to shoulder a greater portion of the expense if they choose to construct a building that uses gas or extend gas service on existing properties. Therefore, this change aligns the cost responsibility with the customer who causes the costs, thereby advances equity for all customers.

5.3.1.6. The Elimination of Residential Gas Line Subsidies Will Not Create a Death Spiral

The Commission disagrees with CCUE that this decision will lead to a "death spiral." We acknowledge that the effect of eliminating gas line extension incentives would be that the cost of constructing a building that uses gas, or extends gas service on existing properties, may increase relative to the status quo. This cost would in turn likely be passed down at the point of sale for a new building or directly absorbed by the customer for an existing building. Neither CCUE nor any other party presents any credible data to show that the gas rates increase will cause the cost of a building to escalate so much that demand for buildings will disproportionately decline, leading to higher gas rates and even less building until the gas utility goes out of business, or some other catastrophic outcome for the gas system. Further, there is no support for the argument that there will be a "death spiral" due to the elimination of gas line extension subsidies that leads to an unreliable and unsafe utility system, as discussed more fully below.

Rather, eliminating gas line extension incentives will send a price signal that building new gas infrastructure is more expensive, thus making dual fuel new construction less desirable and financially riskier. As such, there would be a

gravitation toward all-electric new construction, leading to all the benefits described above, helping California meet its decarbonization goals. We conclude that these benefits outweigh any concerns about a hypothetical "death spiral" due to the decisions we make here.

5.3.1.7. The Elimination of Residential Gas Line Subsidies Maintains Gas System Reliability and Safety

CCUE argues that the elimination of the gas line subsidies will lead to fewer gas customers and higher rates, putting the utilities at risk of not having enough revenue to cover the costs to pay workers to maintain the system, which leads to a less safe and less reliable gas system. CCUE states that some of the anticipated impacts include fewer leaks detected and repaired (impacting both safety and the climate), reduced customer response levels at call centers, extended response time from reconnections, longer service outages, deferred reliability maintenance projects, deferred gas pipeline replacements, and slower emergency response times.[75]

CCUE's concerns are misplaced. The Commission disagrees with CCUE that eliminating gas line extension subsidies would adversely impact gas system reliability and safety. The Commission's regulatory and ratemaking process consistently ensures that utilities have sufficient resources to operate and maintain a safe and reliable system, and minimize rate impacts. The utilities' revenue requirement covers worker compensation, essential work including leak detections and leak repairs, appropriate customer response levels at call centers, reasonable response times, minimizing service outages, not deferring projects

[75] Comments of CCUE on Phase III Staff Proposal at 3-4.

that are necessary for reliability, not deferring replacements, and maintaining responsible emergency response times. There is no credible evidence that the authorized revenue requirements have been, or will be, inadequate to maintain safe and reliable gas systems. And there is certainly no evidence that utilities will not apply for additional funding as and when necessary. In setting the overall revenue requirement, the Commission does not micromanage how utilities spend their authorized revenue. Utility managements are responsible for allocating the authorized revenue (with limited exceptions) to meet all requirements of the utility system, and apply for additional funding when necessary.

But let there be no misunderstanding, safe and reliable services of the utilities the Commission regulate is our top priority. We disagree that the changes we make in this decision compromises that priority in any manner.

5.3.2. Elimination of Gas Line Subsidies for Residential Customers Through a Phased Approach: Denied

This decision denies the Joint IOUs' proposal to eliminate the gas line subsidies through a phased, or delayed, approach. The Joint IOUs argue that: (1) removing the gas line subsidies too quickly could result in a near-term increase in gas rates if the proposed changes substantially reduce the number of new connections relative to the forecasts within the utilities' approved and ongoing ratemaking proceedings; (2) gas utilities have varying schedules for their ratemaking proceedings so a utility-specific phase-in may be appropriate; (3) customers will have time to account for increased project costs; and (4) utilities will have time to study the impact to its electric load profile and

generation needs to ensure the safety and reliability of services.[76] The Joint IOUs recommend a workshop to explore these issues in more detail.

The Commission is not convinced by the Joint IOUs' arguments for a phased approach. Rather, we agree with SCE that we must pursue carbon neutrality with unprecedented urgency and commitment as California is already behind in meeting its 2030 emission reduction targets.[77]

The Joint IOUs do not provide a detailed plan for a phased approach (other than a recommendation to simply delay the elimination of the gas line subsidies). Nonetheless, the Commission considers each of the Joint IOUs' claims with the information we do have but do not find any of them convincing.

The Commission disagrees, for example, that eliminating gas line subsidies now could result in unreasonable near-term rate increases due to a reduction in the number of residential customers. In fact, no credible evidence is presented on what the impact will be on gas rates, let alone that it will be unreasonable. We understand that the change for residential customers due to the policy we adopt today may have an incidental effect on gas rates. We do not, however, foresee that it will be such a significant increase in the near term as to require a phasing in of our policy, particularly given the unprecedented urgency with which we must pursue carbon neutrality. Many variables affect the final determination of the gas rates. The Commission is not convinced that the policy change we adopt today requires special treatment; rather, it can be reasonably addressed when we address all relevant variables in determining gas rates.

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[76] Opening Comments of the Joint IOUs on Phase III Staff Proposal at 9-10.

[77] Comments of SCE on Phase III Amended Scoping Memo and Ruling of Assigned Commissioner at 2.

The Commission disagrees that utilities' varying ratemaking schedules require a utility-specific phase in. No credible evidence is presented that the impact on rates, if any, will be so dramatic that we must account for the timing of various ratemaking proceedings, nor that any effect on rates cannot be addressed within current ratemaking tools.

The Commission also disagrees that customers need more time to adjust. The available evidence is that all electric homes are less costly to construct than dual fuel homes. Customers do not need time to adjust when costs decline. Further, given that the elimination of the gas line subsidies would not take effect until July 1, 2023 (the time required by Pub. Util. Code Section 783(d)), there is already a reasonable amount of time built in for the change, particularly for those customers who still require dual fuel service. Therefore, the Joint IOUs' concerns about sufficient time with regards to the implementation of any changes have already been addressed by statute.

Finally, the Commission disagrees that electric utilities need time to study the impact on load and generation requirements. No credible evidence is presented that the change in the number of residential customers will cause such a dramatic change in the near term as to require delayed implementation in order to study load and generation requirements, particularly with respect to safety and reliability. The changes will be incremental and can be factored into current tools to forecast load and generation requirements to ensure safe and reliable service.

Utilities are obligated to provide safe and reliable service. The Commission adjusts rates so that each utility has the financial resources to do so. Utilities continually consider safety and reliability of their systems and make necessary changes. SCE says, for example, that it continuously evaluates how the grid must

evolve to support California's GHG reduction goals. Each year, SCE reports that it conducts transmission, sub-transmission, and distribution system planning assessments for a 10-year planning horizon that identify the grid needs to accommodate new generation resources, customer load and Distributed Energy Resource growth. SCE says it will continue working with the California Energy Commission (CEC) to develop the building electrification forecast and include it in the Integrated Energy Policy Report load forecast to ensure the reliable and affordable integration of building electrification growth into SCE's annual system planning assessments.[78]

The Commission expects that each electric utility, just like SCE, continuously evaluates how the grid needs evolve to support a wide range of goals, including California's GHG reduction goals.

Based on these considerations, the Joint IOUs' request for additional workshops is unnecessary and denied. We conclude that the elimination of the gas line subsidies for the residential sector effective July 1, 2023 complies with the timelines required under Pub. Util. Code Section 783(d) and should not be further delayed.

5.3.3. Continued Coordination/ Consultation with Other State Agencies: Approved

Cal Advocates recommend that the Commission coordinate with the state agencies that are responsible for the state building code (*e.g.*, the CEC) and that the Commission should "approach GHG reductions broadly and work to promote GHG reduction across all sectors."[79] The Commission agrees with

[78] Opening Comments of SCE on Phase III Amended Scoping Memo and Ruling of Assigned Commissioner at 14.

[79] Opening Comments of Cal Advocates at 3.

Cal Advocates that coordination is critical. The Commission has and will continue to consult with the CEC and CARB, and other agencies as appropriate, on these issues.

The publications of both CEC and CARB reflect relevant views on eliminating line extensions and building electrification, which we note here. The 2021 Integrated Energy Policy Report, published by the CEC, recommends that the "CPUC should continue to investigate eliminating line extension allowances for new gas hookups."[80] CARB has released its draft 2022 Scoping Plan for Assembly Bill 32 compliance, and dedicates an appendix chapter to building electrification, strongly advocating for electrification as a means to reduce GHGs from the building sector.[81] CARB notes that scaling back natural gas infrastructure is a potential action to support a successful transition to building electrification.[82] CARB further notes that the Staff Proposal to eliminate gas line subsidies "can encourage all-electric new construction and help alleviate future gas rate escalation."[83]

The Commission will continue to work closely with CEC, CARB, and other state agencies on these issues to ensure consistency in our approaches to GHG reductions broadly.

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[80] CEC, Final 2021 Integrated Energy Policy Report at 182 (https://efiling.energy.ca.gov/GetDocument.aspx?tn=241599).

[81] CARB, Draft 2022 Scoping Plan, Appendix F (https://ww2.arb.ca.gov/sites/default/files/2022-05/2022-draft-sp-appendix-f-building-decarbonization.pdf).

[82] CARB, Draft 2022 Scoping Plan, Appendix F (https://ww2.arb.ca.gov/sites/default/files/2022-05/2022-draft-sp-appendix-f-building-decarbonization.pdf).

[83] *Id.* at 22-23.

5.3.4. Delay Decision Until the Conclusion of the Long-Term Gas System Planning Rulemaking (R.20-01-007): Denied

SWG recommends that a decision on gas line subsidies be suspended until R.20-01-007 concludes because the relationship between this proceeding and R.20-01-007 requires further analysis, and that "delineating the future of natural gas in California is a necessary threshold issue." They argue that addressing similar forward-looking gas infrastructure issues in separate, concurrent proceedings could result in inconsistent factual findings and policy determinations, potentially causing future confusion and inefficiencies.[84] The Commission disagrees.

R.20-01-007 includes two tracks. The scope of Track 1A includes reliability standards that reflect the current and prospective operational challenges that face gas system operators. Track 1B addresses market structure and regulation. Track 2A addresses the appropriate gas infrastructure for California given the state's GHG reduction laws, addressing gas transmission and distribution infrastructure. Track 2B addresses equity, rate design, and gas revenues, with a particular lens for low-income customers and those residing in disadvantaged communities. Track 2C addresses forecasting and data.[85]

Both R.20-01-007 and this proceeding address issues relating to gas systems; however, the scope of this decision is narrowly focused on the elimination of the gas line subsidies. Our decision on this limited issue here will not have a material impact on any issues scoped in R.20-01-007. Therefore, we

[84] Opening Comments of SWG at 7.

[85] R.20-01-007 Scoping Ruling dated January 5, 2022 at 2-11.

deny SWG's recommendation to delay a decision in this proceeding until R.20-01-007 concludes.

6. Non-Residential Gas Line Subsidies Revisions

Of the 18 parties commenting on eliminating the gas line subsidies for non-residential customers, 12 parties support the Staff Proposal and six oppose.

6.1. Positions of Parties Supporting the Staff Proposal

The 12 parties who endorse the Staff Proposal to eliminate gas line subsidies for the non-residential sector are: SCE, Cal Advocates, CEJA, EDF, NRDC, Sierra Club, TURN, EBCE, MCE, SCP, PCE, and SBUA. In addition to many of the same points made supporting the elimination of the gas line subsidies for the residential sector as discussed above, they make these additional points in support of eliminating the gas line subsidies for non-residential customers:

- Elimination of the gas line subsidies is a reasonable and necessary step in pursuit of reducing GHG emissions given that California is at substantial risk of not achieving its SB 32 requirement to reduce emissions to 40 percent below 1990 levels by 2030, and as such, California must pursue carbon neutrality with urgency;
- Elimination of the gas line subsidies does not equate to a gas ban as builders and customers can continue to build new facilities with gas service capabilities, and there is currently no mandate prohibiting customers from continuing to install gas infrastructure; and
- Large non-residential customers are the most significant contributors to GHG gas emissions with great potential to drive problematic expansion of the main gas line infrastructure further beyond existing use areas.

6.2. Positions of Parties Opposing the Staff Proposal

The six parties who oppose the Staff Proposal to eliminate gas line subsidies for the non-residential sector are: PG&E, SDG&E, SoCalGas, SWG, Clean Energy, and CCUE. In addition to many of the same points made opposing the elimination of the gas line subsidies for the residential sector as discussed above, they make these additional points in opposition to eliminating the gas line subsidies for non-residential customers:

- There is continued need for gas and the natural gas system specifically in the industrial sectors that have yet to see energy options that can help them transition to a decarbonized future. Cleaner gases can replace or contribute to the natural gas service and full electrification, contributing to California's energy objectives;
- Removing gas line subsidies for large non-residential or industrial customers will result in a net increase in GHG emissions because it will disincentivize the use and production of cleaner gases, which can replace higher GHG emitting fuels, or "dirtier fuels";
- Removing gas line subsidies for large non-residential or industrial customers will increase project costs and create additional hardship, which may cause developers to slow down projects, abandon projects or develop projects outside California, negatively impacting California's economy; and
- Minimizing short lived climate pollutants (SLCPs) should be the Commission's top priority, as opposed to eliminating non-residential gas line subsidies, as these are the only reductions that benefit the climate immediately.

6.3. Alternate Proposals

6.3.1. Exemptions for Specific List of Projects that Provide Environmental or Financial Benefits (Joint IOUs)

The Joint IOUs propose to continue the non-residential gas line subsidies for several categories of non-residential projects that provide environmental or financial benefits to California ratepayers. They also propose a mechanism to update these categories periodically. According to the Joint IOUs, the following 10 non-residential projects would provide environmental or financial benefits to California ratepayers:[86]

- Renewable Natural Gas (RNG) or Hydrogen (Piped and Virtual);
- Compressed Natural Gas (CNG), Liquid Natural Gas, and Hydrogen Stations;
- Electric Generation Projects;
- Backup Generation Projects;
- Facility Conversions (facilities switching from dirtier fuels);
- Large Commercial Customers;
- Industrial Customers;
- Transmission Customers;
- Critical Load; and
- Restaurants (proposed by SDG&E and SoCalGas).

The Joint IOUs also propose that the categories of customers receiving gas line subsidies would be reviewed via a Tier 2 AL (to be filed every three years starting in 2026) or that a cadence for re-visiting the subsidies be established in the ongoing long term gas planning proceeding (R.20-01-007). In support, they

[86] Opening Comments of the Joint IOUs on Phase III Staff Proposal at 7.

say the review would ensure that gas ratepayers continue to benefit from providing gas line subsidies. According to the Joint IOUs, "non-residential customers identified as having economic and environmental benefits to gas ratepayers can shift over time and that the removal of residential allowances may have a negative impact on affordable housing developers."[87]

Additionally, PG&E proposes two new methods for calculating the allowance amounts for non-residential projects that provide environmental or financial benefits to California ratepayers: (1) the ability for all current calculations of distribution to be applied to the non-residential projects; and (2) the addition of a graduated discount when additional load reduces GHG emissions. PG&E also proposes that the gas line subsidies be modified such that customers cannot switch from core service to noncore service until the allowance amount is fully recovered through revenue. In support, PG&E states that the current practice of switching from core to non-core service creates an unsustainable loophole where core customers can receive a higher allowance amount which may not be fully repaid should they switch to non-core service before the allowance amount is recovered.[88]

6.3.2. Exemptions for Projects That Enable Hydrogen, RNG and CNG Use (Clean Energy)

Clean Energy recommends that the Commission prioritize the phase-out of diesel in the transportation, electricity, and agricultural sectors. To do this, Clean Energy proposes maintaining incentives for customers seeking to develop hydrogen, agricultural customers seeking to produce biogas and RNG from

[87] Opening Comments of the Joint IOUs on Phase III Staff Proposal at 10.

[88] Opening Comments of the Joint IOUs on Phase III Staff Proposal at 13.

manure, and private companies investing in CNG fueling stations that distribute RNG to facilitate reductions in SLCP.[89]

For the transportation sector, Clean Energy states that the gas line subsidies make construction of new CNG fueling stations financially viable and present opportunities for collocation with hydrogen fueling stations.[90] For the electricity sector, they argue that renewable gas, including biogas and hydrogen from organic waste, can provide the same reliability services with far lower emissions than diesel backup generators.[91] For the agricultural sector, they state that agricultural feedstock RNG (particularly negative carbon RNG feedstock such as animal agriculture) can significantly lower GHG emissions, and help the state achieve its climate goals.[92] Therefore continuing gas line subsidies for these customers will encourage further development of these "carbon beneficial" fuel options.

6.3.3. Application Process for Select Projects that Provide Environmental or Financial Benefits (Joint Parties and TURN)

The Joint Parties and TURN oppose providing any exceptions to offering the gas line subsidies, but state that if the Commission decides to provide limited exemptions, it should require the IOUs to submit a stand-alone application seeking ratepayer support for specific line extension projects. They assert that the

[89] Comments of Clean Energy on Amended Scoping Memo and Ruling and Staff Proposal at 2-3.

[90] Comments of Clean Energy on Amended Scoping Memo and Ruling and Staff Proposal at 11-13.

[91] Comments of Clean Energy on Amended Scoping Memo and Ruling and Staff Proposal at 6.

[92] Response of Clean Energy to Assigned ALJs' Ruling Seeking Clarification and Additional Information at 10-15.

IOUs should demonstrate that ratepayer funding is just and reasonable in light of reasonably anticipated ratepayer benefits and in furtherance of California's decarbonization policy.[93] Specifically, the Joint Parties propose that the application meet the following minimum criteria: (1) the extension does not emit local criteria or toxic air pollution; (2) the extension is not located in an environmental and social justice community; (3) the extension is consistent with all California climate goals; (4) the project does not claim any environmental credits; and (5) there are no feasible non-pipeline alternatives to the extension.[94] Given the need to verify these facts with discovery, the Joint Parties recommend an expedited application process that should receive at least the same level of scrutiny as a Tier 3 AL, where the applicants must demonstrate the factual basis for its assertions, and parties are allowed to conduct discovery to verify that each of the suggested criteria have been met. TURN also recommends that if exceptions are made to preserve gas line subsidies for some non-residential customers, the Commission should protect residential customers and require the non-residential customer classes to subsidize the costs.[95]

6.3.4. Assistance for Low Income, Rural and Small Businesses (SBUA)

SBUA supports the elimination of gas line subsidies for non-residential customers, but recommends replacing the allowance regime with direct assistance to small businesses not currently connected to gas infrastructure but who upgrade to high-efficiency electric appliances in furtherance of the state's

[93] Reply Comments of Joint Parties and TURN on Phase III Staff Proposal at 10-14.

[94] Response of CEJA, EDF, NRDC, and Sierra Club to the Assigned ALJs' Ruling Seeking Clarifications and Additional Information at 6-10.

[95] Reply Brief of TURN at 8.

GHG emission goals. More specifically, they propose: (1) opening a further phase of this proceeding to understand the support required to assist small businesses in overcoming barriers to electrification, such as by providing subsidies for appliance or panel upgrades in locations where stranded asset problems are most likely to be acute or where propane reliance is high; (2) establishing a pilot project to investigate the effectiveness of electrification incentive programs, akin to the San Joaquin Valley Pilots (D.18-12-015) referenced in the Staff Proposal; and (3) requiring electric utilities, through the advice letter process, to gather further data on bill savings comparisons between gas and electric usage and propose programs to address financial barriers to adoption of electric appliances.[96]

6.4. Discussion

6.4.1. Elimination of Non-Residential Gas Line Subsidies: Approved

This decision adopts the staff's proposal to eliminate the non-residential gas line subsidies effective July 1, 2023. The elimination of subsidies applies to new applications for gas line extensions submitted on or after July 1, 2023, and will not affect applications submitted before July 1, 2023. Within 30 days of the date of this order, the gas IOUs shall each submit a Tier 2 AL to revise their respective gas rules to implement this decision.

Gas line subsidies are eliminated for the non-residential sector for the same reasons as for the residential sector. These benefits include significant ratepayer savings, reductions in GHG emissions, combating climate change, improved overall quality of life, greater certainty for the builder community, and benefits

[96] Opening Brief of SBUA at 8-9.

to low-income customers. The Commission reiterates that the elimination of these subsidies is one of many necessary and important steps in furthering California's decarbonization goals, while easing the burden on gas ratepayers, ensuring grid safety and reliability, and continuing to promote alternative clean fuels.

We also adopt the proposal of the Joint Parties and TURN, with modifications, to allow individual applications for the provision of gas line subsidies for select unique projects meeting specific application criteria discussed below.

The Commission agrees with SBUA and other parties that large non-residential customers are the most significant contributors to GHG gas emissions,[97] making it especially important to adopt this policy change for this customer segment. Absent this change, non-residential customers create the great potential to drive problematic expansion of gas line infrastructure beyond existing use areas, and create additional stranded investment.

Therefore, we eliminate gas line subsidies to promote the many benefits of this policy. However, gas line subsidies may be extended to a limited number of unique gas line extension projects meeting specific criteria, and will be reviewed through the application process outlined below.

6.4.2. Exemptions for Specific List of Projects that Provide Environmental or Financial Benefits: Denied

This decision denies the Joint IOUs' proposal to continue offering gas line subsidies to their proposed list of 10 non-residential project categories that might

[97] Reply Brief of SBUA at 2 and https://ww2.arb.ca.gov/ghg-inventory-data.

provide environmental and financial benefits to ratepayers. We are not convinced by the Joint IOUs' argument that an exception for a specific group of projects is necessary given the urgent nature of California's decarbonization goals and the likelihood that any new gas investments could become stranded assets in the future. Rather, as explained below, the potential benefits of an exemption for a specific group of customers are outweighed by the environmental and stranded investment costs.

The Joint IOUs propose this exception for a group of large non-residential customers that they argue provide environmental and financial benefits. The categories, however, are very broad and vague, such as "large commercial customers" and "industrial customers." It would not be reasonable to adopt a category as broad as "industrial customers" since not every project serving an industrial customer can be said to provide environmental or financial benefits to California ratepayers. Adopting the Joint IOUs' proposal as is could effectively make the elimination for the gas line subsidies largely meaningless, while adding confusion and administrative inefficiencies to the process as the categories are reviewed and parties argue for adjusting the categories.

Moreover, most parties, even when prompted by the assigned ALJs to be more specific,[98] did not provide a sufficiently unambiguous and clear definition of what constitutes environmental and financial benefits for the Commission to adopt this as a workable basis to establish categories. Instead, the Joint IOUs only provide a list of 10 categories they claim provide financial and/or environmental benefits to California ratepayers.

[98] January 28, 2022 ALJ Ruling Seeking Clarification and Additional Information, Attachment 1 at 3.

PG&E and Clean Energy, on the other hand, propose the following definitions within the limited context of this proceeding. PG&E proposes:[99]

- Direct Environmental Benefit: A project offers a direct environmental benefit where it provides on-site GHG, NOx, or other pollutant reduction compared an existing fuel baseline.
- Indirect Environmental Benefit: A project offers an indirect environmental benefit where it displaces either existing gas system emissions (*e.g.*, through renewable natural gas) or off-site (*e.g.*, through CNG) GHG, NOx, or other pollutant emissions.
- Financial Benefit: Broadly, a new gas connection offers financial benefit to all gas ratepayers where the connecting customer financially contributes, via gas rates, in excess of the costs to extend gas service to that customer. The customer may also offer financial benefit in the form of externalities that are more difficult to quantify (*e.g.*, job creation, increased state and local tax revenue, and local development).

Clean Energy proposes:[100]

- Environmental Benefit: (a) receipt of any tradable environmental attributes; (b) reduction of SLCPs; (c) reduction of GHG emissions; or (d) reduction of regulated air or water pollutants.
- Financial Benefit: (a) addresses the pay-back period for the gas line subsidies; (b) reduces system costs by more than the cost of the subsidy; or (c) contributes significantly to racial or social equity, public health, community resilience, or a robust economy.

[99] PG&E's Response to Assigned ALJ's Ruling Seeking Clarification and Additional Information at 6-7.

[100] Reply Comments of Clean Energy on Amended Scoping Memo and Ruling and Staff Proposal at 4.

We appreciate the proposals of PG&E and Clean Energy but find these definitions overly broad and lacking in adequate benchmarks or specific criteria for how to establish the 10 categories for potentially vast numbers of different projects, all of which would qualify for the exception. Absent an adequate definition or a reasonably accurate baseline for calculating environmental or financial benefits, many categories of projects could broadly make a case for the exception, and many customers might be granted exemptions even if the criteria are imprecise. We share TURN's concern that:

> Any project that adds new customer load to the gas system could, all else being equal, provide a contribution to margin for at least some amount of time. However, any system buildout today could become a stranded asset well before the end of the asset's life because of electrification — whether mandated by state or local building codes or inspired by ratepayer-funded incentive programs and market transformation. This serious risk cuts against any near-term financial benefits from increased sales associated with new customer load.[101]

Thus, along with the lack of adequate definitions and criteria provided by the Joint IOUs, PG&E and Clean Energy, and without sufficient information and analysis on the record, we are not convinced that continuing gas line subsidies for this broad set of non-residential projects would lead to the benefits claimed.

We acknowledge that there may be limited circumstances where gas line extensions for some non-residential projects can be beneficial. Nonetheless, these potentially limited circumstances are not sufficient to warrant blanket subsidies for various broad categories of projects, such as the 10 project types proposed by the Joint IOUs. Not only would this be complicated, but more importantly, this

[101] Opening Brief of TURN at 8.

would be misaligned with California's overall decarbonization goals. Exceptions for such broad categories of projects would perpetuate, even if on a smaller scale, the continued reliance on gas and locking in gas use for the life of the asset.

Instead, we adopt a limited alternative below that considers applications for specific and unique projects meeting a narrow set of criteria that may warrant gas line subsidies. This will account for the special cases of environmental, financial, or other benefits without creating up to 10 broad project categories.

This decision also denies PG&E's proposal for two new methods for calculating allowance amounts. We find this proposal now moot since we eliminate all gas line subsidies. Moreover, we do not wish to complicate the application process described below with additional factors.

6.4.3. Exemptions for Projects That Enable Hydrogen, RNG and CNG Use: Denied

This decision denies Clean Energy's proposal to continue offering blanket gas line subsidies for non-residential transportation, agricultural, commercial, and industrial projects that enable RNG use in order to prioritize reduction in SLCP emissions. We are not convinced by Clean Energy's argument that gas line subsidies should continue to be offered to the non-residential sector to advance the goal of reducing SLCPs. Rather, we believe that ending gas line subsidies and supporting the hydrogen/RNG/CNG sector to reduce SLCPs can be successfully achieved together.

Clean Energy claims that the lack of gas line subsidies could be the sole reason that a new project will not be built, because the project may no longer be economical.[102] Clean Energy argues that typically, a CNG project will cost

[102] Opening Brief of Clean Energy at 24.

approximately $1.5-$2.0 million plus a gas line extension cost of $400,000-$500,000 — approximately 25 percent of the investment.[103] Clean Energy does not, however, state whether the full gas line extension cost is eligible for gas line subsidies. As noted earlier in this decision, gas line extension costs are made up of a refundable portion and a non-refundable portion, with only the refundable portion being eligible for a subsidy. Clean Energy also does not provide data on average subsidies received for its projects. Recent data provided by the IOUs show the following average non-residential subsidies paid below.

Table 5. Average Subsidies Paid to Non-Residential Projects in 2021

	Average Subsidies Paid Per Project in 2021[104]			
Gas Line Subsidies	**PG&E**	**SoCalGas**	**SDG&E**	**SWG**
Allowances	$12,030	$7,058	Not Provided	$107,228
Refunds	$490	$0	$9,056	Not Provided
Discounts	$8,702	$74	Not Provided	$4,418

Although these average subsidies are not identified by project type, we note that they are far below the CNG gas line extension estimate of $400,000 to $500,00[105] provided by Clean Energy. Given the absence of sufficient information to support Clean Energy's claim, and based on the gas IOUs' 2021 average subsidies as shown above, the Commission is not convinced by the speculative argument that eliminating the gas line subsidies for non-residential project could be the sole reason that a new project will not be built.

[103] *Id. at* 30.

[104] April 18, 2022 ALJ Ruling, Attachment 5.

[105] Assuming the full amount is refundable as defined under the gas rules.

While this analysis suggests that the average subsidies may be small compared to the overall project costs, we acknowledge that there may be some CNG/RNG/hydrogen projects at the margin where the subsidy makes up a larger portion of total project costs. However, no compelling evidence demonstrates that the gas line subsidies are actually necessary, or are the tipping point, to encourage these larger customers to make the "cleaner" gas investments. Rather, many factors are involved in a developer deciding to develop or not develop a project. While we understand that the elimination of these subsidies would make some projects more expensive, simply pointing this out does not prove it is the driving or controlling factor in a decision, and we are not convinced, absent specific evidence or examples of representative projects, that it is a significant enough change to halt such projects altogether. This is especially true given that there are existing subsidies and programs that offer incentives for the development of alternative fuels, including $40 million for bio-SNG (synthetic natural gas) incentives that was authorized in D.22-02-025.[106]

The Commission also disagrees with Clean Energy that by making these projects more expensive, we are decelerating the move towards the use of cleaner fuels in the transportation/mobility sector that would otherwise reduce GHG emissions and help displace SLCPs. Many factors affect the use of alternative fuels in transportation, such as technology and state policy. As discussed above, gas line subsidies date back to the 1970s and the current rules on gas line subsidies were adopted in 2007. Yet, Clean Energy's data shows that only

[106] D.22-02-025, Ordering Paragraph 43.

3 percent of trucks in large fleets are powered by natural gas, and 0.01 percent are powered by hydrogen.[107]

Although we agree with Clean Energy that the use of CNG/RNG/ hydrogen is a preferred option over diesel and other "dirtier" fuels during a transition to full electrification, it is still not the preferred option in the long term over full electrification.[108] Our priority in the long term is to move away from fossil fuels altogether, including in the transportation sector, as opposed to supporting less harmful fossil fuels. This has been consistent and reiterated in several Commission proceedings.[109] It is also the policy of our sister agencies, which have also encouraged the move away from fossil fuel investment. For example, the CEC's California Clean Transportation Program has shifted focus significantly since 2019 to heavily prioritize zero emission vehicles (ZEVs) over near zero emission vehicles. CARB has adopted rules requiring 100 percent medium duty and heavy duty ZEVs by 2045 (to the fullest extent feasible). It has explained that "Infrastructure for methane trucks is expensive and would become a stranded asset if use of those [electric-fueled] trucks continued to expand; EV infrastructure, in contrast, will be needed indefinitely."[110] In light of these state policies, long term gas line subsidies to expand CNG infrastructure does not merit a categorical exemption from our overall policy adopted here.

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[107] Opening Brief of Clean Energy at 28.

[108] Further, even though electrification is our preferred option, we recognize that for now, RNG plays an important role in reducing GHG emissions. This decision is not intended to conflict with that policy, as outlined in D.22-02-025.

[109] D.22-03-006, D.19-09-051, D.22-02-025, and Rejection of SoCalGas's AL 5590.

[110] CARB Technical Analysis of End of Useful Life Scenarios at 2 (https://ww2.arb.ca.gov/resources/documents/technical-analysis-end-useful-life-scenarios-statewide).

Additionally, we note that most of the cleaner fuels are already heavily subsidized, and eliminating the gas line subsidies would not undermine their development in any significant way. The table below summarizes these subsidies as approved by the Commission, and does not include additional subsidies that may be available from other sources.

Table 6. Commission Approved Subsidies for Alternate Fuels

Fuel type	Subsidy Budget	Authorized By
Bio-SNG	$40 million	D.22-02-025
Biomethane	$40 million	D.15-06-029
Biomethane (augment)	$40 million	D.20-12-031

Lastly, we reiterate that the elimination of these subsidies does not remove the builder or developer's choice to build the CNG/RNG facility, it only requires that the costs caused by new customers be paid by those customers. And, in the limited cases where a gas line subsidy may still be warranted, we provide an application process below to consider specific, unique projects that claim to be unable to proceed without a gas line subsidy.

6.4.4. Application Process for Select Projects that Provide Environmental or Financial Benefits: Approved with Modifications

This decision approves the Joint Parties and TURN's proposal for an application process, with modifications, for those specific, unique non-residential projects where a gas line subsidy may still be warranted. For these projects, the gas IOUs shall evaluate the project based on the criteria established in this decision and file an application with the Commission for approval of a gas line subsidy on behalf of the project applicant(s).

The IOUs shall ensure that projects seeking a gas line subsidy shall meet the following minimum criteria based on the information provided by the applicant(s) before including it in an annual filing to the Commission seeking such subsidies. These minimum requirements are:

(1) The project will lead to a demonstrable reduction in GHG emissions;

(2) The gas line extension required for the project is consistent with California's climate goals, including those articulated in SB 32 (Pavley, 2016); and

(3) The project applicant demonstrates that it has no feasible alternatives to the use of natural gas, including electrification.

We do not include the other criteria proposed by the Joint Parties and TURN (the extension is not located in an environmental and social justice community, and the project does not claim any environmental credits) at this time. We are not persuaded that these additional criteria are necessary in assessing the impacts of the project.

If there are projects seeking gas line subsidies that an IOU determines meets the above criteria, the IOU shall file an annual application, by July 1 of each year beginning in 2023, and include all qualified projects requesting a gas line subsidy. Even though this decision eliminates gas line subsidies for all customer classes, it does not change the methodology for the calculation of gas line subsidies if the Commissions grants gas line subsidies for specific projects through the application process. In its annual filing, each IOU should include an update to the non-residential gas line extension allowance calculations based on the current methodology (including all inputs used, *e.g.*, cost of service factor). The IOUs, on behalf of the project applicant(s), must demonstrate the factual basis for the project applicants' assertions, and confirm that the minimum

requirements have been met based on the information provided by applicants.[111] The Commission will evaluate the types of applications that are found to be deserving of gas line subsidies over the next few application cycles, and may revisit the need for categorical exemptions at a later time. The IOUs may propose potential categorical exemptions in their annual filing after two application cycles. The IOUs may also reference similar projects that have received gas line subsidies in their annual filing, and over time, this could reduce the burden on applicants and IOUs in demonstrating eligibility for these subsidies.

Lastly, the Commission denies TURN's proposal to modify the cost allocation/collection methodology of these subsidies to only require non-residential customer classes to subsidize the costs.[112] We do this because these projects, if approved for subsidies through this application process, would have demonstrated that they will reduce GHG emissions and be consistent with California's climate goals. This benefits all ratepayers, not just the non-residential customer class. The Commission also believes the resulting subsidies, if any, will not be so large as to justify the additional administrative burden to distribute the costs in proportion to the benefits received by customer class.

6.4.5. Assistance for Low Income, Rural and Small Businesses: Approved with Modifications

We approve SBUA's proposal to further investigate the needs of small businesses not currently connected to gas infrastructure that move towards electrification. Although this decision does not make any special exceptions for

[111] Each IOU must determine that each applicant's project meets the criteria based on the information provided by the applicants. In addition, each IOU's application may include prepared proposed testimony from the applicant in support of the application.

[112] Reply Brief of TURN at 8.

the treatment of small businesses in regard to electrification, we are committed to considering the unique challenges to electrification faced by small businesses in future phases of this proceeding.

7. Compliance with Pub. Util. Code Section 783(b)-(d)

Pub. Util. Code Section 783(b) states that:

> Whenever the commission institutes an investigation into the terms and conditions for the extension of services provided by gas and electrical corporations to new or existing customers, or considers issuing an order or decision amending those terms or conditions, the commission shall make written findings on all of the following issues:
>
> (1) The economic effect of the line and service extension terms and conditions upon agriculture, residential housing, mobile home parks, rural customers, urban customers, employment, and commercial and industrial building and development.
>
> (2) The effect of requiring new or existing customers applying for an extension to an electrical or gas corporation to provide transmission or distribution facilities for other customers who will apply to receive line and service extensions in the future.
>
> (3) The effect of requiring a new or existing customer applying for an extension to an electrical or gas corporation to be responsible for the distribution of, reinforcements of, relocations of, or additions to that gas or electrical corporation.
>
> (4) The economic effect of the terms and conditions upon projects, including redevelopment projects, funded or sponsored by cities, counties, or districts.
>
> (5) The effect of the line and service extension regulations, and any modifications to them, on existing ratepayers.

(6) The effect of the line and service extension regulations, and any modifications to them, on the consumption and conservation of energy.

(7) The extent to which there is cost-justification for a special line and service extension allowance for agriculture."[113]

Pub. Util. Code Section 783(c) states that:

The commission shall request the assistance of appropriate state agencies and departments in conducting any investigation or proceeding pursuant to subdivision (b), including, but not limited to, the Transportation Agency, the Department of Food and Agriculture, the Department of Consumer Affairs, the Bureau of Real Estate, and the Department of Housing and Community Development.[114]

Lastly, Pub. Util. Code Section 783(d) requires:

Any new order or decision issued pursuant to an investigation or proceeding conducted pursuant to subdivision (b) shall become effective on July 1 of the year which follows the year when the new order or decision is adopted by the commission, so as to ensure that the public has at least six months to consider the new order or decision.[115]

7.1. Staff Proposal

In response to Pub. Util. Code Section 783(b) the Staff Proposal addresses each of the seven issues as follows.[116]

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[113] *See* https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=783&lawCode=PUC.

[114] *See* https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=783&lawCode=PUC.

[115] *See* https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=783&lawCode=PUC.

[116] Phase III Scoping Memo, Appendix A at 33-36, 38-40, and 42-45.

On Issue 1, Staff expects that the elimination of gas line subsidies would increase the number of newly constructed all-electric buildings and that prices for those all-electric buildings will likely be less than those for an equivalent newly constructed dual fuel building. Dual fuel buildings constructed without gas line subsidies would be expected to cost more than they do today, but minimally (anywhere from 0.07 percent to 0.25 percent depending on the gas line subsidies type). Whether or not customer bills would be higher or lower in a new all-electric building vis-à-vis a new dual fuel building would depend on numerous factors that include tariff type, climate zone, future electricity prices, future gas prices, customer energy consumption habits, and time of energy usage.

On Issue 2, Staff does not expect the elimination of gas line subsidies to affect the current methods of providing transmission or distribution facilities for future customers, as the Staff Proposal is not proposing to modify such rules. If gas line subsidies are eliminated as proposed, and builders increase their rate of all-electric new construction, builders building dual fuel new construction further away from a point of gas pipeline interconnection could expect to pay more than they otherwise would be expected to if they have to pay for additional trenching and infrastructure that neighboring all-electric buildings did not need and thus did not help pay to extend from its current cut-off location.

On Issue 3, Staff expects the elimination of gas line subsidies for all new construction to result in increased costs to any customer seeking to extend a gas line. Depending on what infrastructure upgrades are necessary to extend gas service to the customer's building, the increased costs would vary.

On Issue 4, Staff does not expect the elimination of gas line subsidies for all new construction to result in changes specific to projects sponsored by cities,

counties, or districts, as the Staff Proposal is not proposing any such changes. Should those projects be constructed all-electric, they will be less expensive than they are today, and should those projects be constructed dual fuel, they are anticipated to be only slightly more expensive than they are today.

On Issue 5, Staff expects the elimination of gas line subsidies for all new construction to lead to an annual reduction of approximately $115,528,305 in allowances,[117] $2,625,678 in refunds,[118] and $26,195,639 in discounts[119] (with partial data for SDG&E) as a result of gas ratepayers no longer having to pay for gas line subsidies.[120] If a new building were to be constructed dual fuel without a gas line subsidy, gas ratepayers would save even more as a result of an additional customer sharing in costs necessary to maintain the common carrier pipeline network.

On Issue 6, Staff expects the elimination of gas line subsidies for all new construction to result in less gas consumption and more electricity consumption. Because gas consumed in California is overwhelmingly non-renewable and electricity is increasingly carbon-free, the encouragement of fuel substitution associated with adoption of Staff's recommendation would result in fewer GHG emissions and less air pollution. However, additional electrical load will gradually result in the need for additional electricity procurement and could pose challenges to managing winter peak electric demand if not properly planned for.

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[117] Phase III Scoping Memo, Appendix A at 35.

[118] Phase III Scoping Memo, Appendix A at 39.

[119] Phase III Scoping Memo, Appendix A at 44.

[120] We note that since the publication of the Staff Proposal, the gas IOUs provided updated projections. (*See* April 18, 2022 ALJ Ruling, Attachment 5.)

On Issue 7, Staff does not recommend any special allowance for agricultural customers and, as such, there is no cost-justification for such an allowance. Agricultural operations typically use gas primarily for greenhouse heating and grain drying, both of which can be done using electricity. Additionally, the small property price increase for new dual fuel construction that can be expected if Staff's recommendation is adopted is insufficiently high to merit a special allowance for any customer class.

In response to Pub. Util. Code Section 783(c), Commission staff requested the assistance of the California State Transportation Agency, California Department of Food and Agriculture, DCA, DRE,[121] and HCD in developing the recommendations in its Staff Proposal. Staff states that the feedback that was received was considered as part of Staff's recommendations. Additionally, Staff consulted with CARB, CEC, and the California Strategic Growth Council.[122]

Lastly, in response to Pub. Util. Code Section 783(d), Staff recommends an effective date of July 1, 2023, in compliance with the minimum time required.

7.2. Positions of Parties Supporting the Staff Proposal

Of the 14 parties commenting on the Staff Proposal's findings pursuant to Pub. Util. Code Section 783(b), 10 parties agree with the Staff Proposal's assessment of the seven issues and agree that eliminating gas line subsidies is within the Commission's legal purview. These parties are: Cal Advocates, CEJA, EDF, NRDC, Sierra Club, TURN, EBCE, MCE, SCP, and PCE. They make several points in support.

[121] Statute requires the CPUC to request the assistance of the Bureau of Real Estate, which has since become DRE.

[122] Phase III Scoping Memo, Appendix A at 2.

- The Staff Proposal sufficiently addresses the seven issues to make the requisite written findings;
- Statute does not specify the exact nature of the economic analysis required for the Commission to make the necessary findings pursuant to this section; and
- Statute does not require that new rules result in any particular findings (*e.g.*, favorable rate effects for customers) simply that they be documented.

7.3. Positions of Parties Opposing the Staff Proposal

Of the 14 parties commenting on the Staff Proposal's findings pursuant to Pub. Util. Code Section 783(b), four parties disagree with the Staff Proposal's assessment of the seven issues citing insufficient analysis. These parties are: SDG&E, SoCalGas, SBUA, and Clean Energy. They make several points in opposition.

- The record of this proceeding does support written findings on all seven issues;
- There has been no examination of the impacts on agriculture, mobile home parks, rural and urban customers, employment, or commercial and industrial buildings and development (Pub. Util. Code Section 783(b)(1));
- There has been no examination of the impacts to customer bills (Pub. Util. Code Section 783(b)(5));
- There has been no discussion of the impact on the development of RNG fueling stations or hydrogen production sites;
- The Staff Proposal does not address the equity concern between the customer applying for the extension now and future customers applying for line extensions at a later time (Pub. Util. Code Section 783(b)(2));
- The Staff Proposal failed to show that staff consulted any city, county or district before arriving at the conclusion that

eliminating gas line subsidies would not have any effect on redevelopment projects, funded or sponsored by cities, counties, or districts (Pub. Util. Code Section 783(b)(4)); and

- A study should be conducted on the economic effects on residential housing, rural customers and urban customers and must include low-income customers, disadvantaged communities, and the affordable housing sector.

7.4. Discussion

7.4.1. Compliance with Pub. Util. Code Section 783(b)

In this decision, the Commission makes findings on each of the seven issues included in Pub. Util. Code Section 783(b). We do so by relying on the best information we have in the record of this proceeding.

We agree with the Joint Parties and TURN that the statute requires the Commission to make findings on questions such as "the effect of requiring new or existing customers applying for an extension to an electrical or gas corporation to provide transmission or distribution facilities for other customers who will apply to receive line and service extensions in the future." However, it does not require that the Commission arrives at any particular conclusions (*e.g.*, favorable rate effects for customers) simply that the Commission arrives at written findings for all seven issues set out in Pub. Util. Code Section 783(b).[123]

Moreover, the statute does not require the Commission to conduct or commission a study, or specify the exact nature of the economic analysis required before the Commission can make the necessary findings.

The Commission has considered the potential impacts of these changes as further discussed below and concludes that eliminating gas line subsidies will

[123] Opening Comments of Joint Parties and TURN on Phase III Staff Proposal at 4.

have a net positive impact on all sectors mentioned in Pub. Util. Code Section 783(b) for all the reasons discussed in earlier sections of this decision. The record in this proceeding provides the Commission sufficient basis to eliminate gas line subsidies for all customer classes and we determine that this decision is in California's best interest and is consistent with other Commission decisions and legislative intent. More specifically, we make the following findings on each of the seven issues.

(1) The economic effect of the line and service extension terms and conditions upon agriculture, residential housing, mobile home parks, rural customers, urban customers, employment, and commercial and industrial building and development.

The Commission finds that the elimination of the gas line subsidies will have an overall net positive economic effect on these groups of customers. Gas rates paid by all gas customers will be reduced due to the reduction in gas line subsidies, estimated at an annual savings of $164 million.

The Commission agrees with the Joint Parties that in light of state climate and equity objectives and the importance of price signals to discourage the expansion of the gas system and reliance on gas appliances, the benefits of ending gas line extensions outweigh the economic impact upon those customers that may incur additional line or service extension costs by continuing to choose to build an extension connecting to the gas system.[124] We also note that there are programs that can help reduce any potential cost increase for these groups including the Manufactured and Mobile Homes Program, the Mobile Home Park Utility Conversion Program, and BUILD.

[124] Opening Brief of Joint Parties at 19-21.

In terms of employment, and as discussed in this decision, the Commission finds that there will likely be a net positive impact as we are likely to see an increase in demand for skilled workers in several economic sectors, including in the electric industry, construction jobs for energy efficiency improvements and building retrofits.

In terms of commercial and industrial building and development, and as discussed in this decision, the Commission finds that there will likely be an increase in the number of newly constructed all-electric buildings which will likely cost less than newly constructed dual fuel buildings.

Therefore, the Commission finds the "economic effect of gas line and service extension terms and conditions upon agricultural, residential housing, mobile home parks, rural customers, urban customers, employment, and commercial and industrial building and development" to be overall net positive.

(2) The effect of requiring new or existing customers applying for an extension to an electrical or gas corporation to provide transmission or distribution facilities for other customers who will apply to receive line and service extensions in the future.

The Commission agrees with the Staff Proposal[125] and the Joint Parties[126] that the elimination of gas line subsidies will have no effect on the current methods of providing transmission or distribution facilities for future customers.

We note that the elimination of gas line allowances may shift who pays which costs, but there is no change in the extent to which new or existing customers applying for an extension provide transmission or distribution facilities for future customers. We acknowledge that builders building dual fuel

[125] Phase III Scoping Memo, Appendix A at 34, 39, and 42-43.

[126] Opening Brief of Joint Parties at 21.

new construction away from a point of gas pipeline interconnection may pay more (*e.g.*, for additional trenching and infrastructure) than neighboring all-electric buildings (who do not need the additional trenching and gas infrastructure).

With respect to the magnitude of any such cost shift, no party presented credible evidence that it would be material and significantly disrupt necessary expansion of utility service. In light of the state's climate and equity objectives, the benefits of ending these subsidies to all gas customers outweigh any economic impact of developers that may receive lower subsidies due to neighboring developments opting for all-electric designs.

Therefore, we find that the actions in this decision do not have the "effect of requiring new or existing customers applying for a gas line extension to provide transmission and distribution facilities to other customers who receive line and service extension in the future." We find that the effect of this decision is limited to a shift in who pays which costs, this is not a material effect, and the negative effects on some customers, if any, are offset by the overall positive effects of reducing GHG emissions, improved quality of life and health for customers, hundreds of millions of dollars in total ratepayer savings annually, greater equity for low-income customers, and greater certainty for the builder and contractor community.

(3) The effect of requiring a new or existing customer applying for an extension to an electrical or gas corporation to be responsible for the distribution of, reinforcements of, relocations of, or additions to that gas or electrical corporation.

The Commission agrees with the Staff Proposal[127] and the Joint Parties[128] that the elimination of gas line subsidies for all new construction will result in increased costs to any customer choosing to extend a gas line, with costs depending on what infrastructure upgrades are necessary to extend gas service to the customer's building. However as mentioned above, the benefits of ending these subsidies to all gas customers outweigh any economic impact on developers seeking to extend gas lines. Therefore, we find the "effect of requiring a new or existing customer applying for an extension to an electrical or gas corporation to be responsible for the distribution of, reinforcements of, relocations of, or additions to that gas or electrical corporation" to be: the new or existing customer will be responsible for and must pay the costs that are caused by that customer's line extension (including reinforcements, relocations, or additions). These costs are outweighed by the economic and environmental effects along with increased equity of having the cost-causer pay the costs that are incurred.

(4) The economic effect of the terms and conditions upon projects, including redevelopment projects, funded or sponsored by cities, counties, or districts.

The Commission agrees with the Joint Parties that the elimination of gas line subsidies may increase project costs (including those that are funded or sponsored by cities, counties, or districts) that choose to connect to the gas system.[129] However, as discussed above, the rates paid by all gas customers (including cities, counties, or districts as utility customers themselves) will be

[127] Phase III Scoping Memo, Appendix A at 34, 39, and 43.

[128] Opening Brief of Joint Parties at 21.

[129] Opening Brief of Joint Parties at 21-22.

reduced due to the millions of dollars in ratepayer savings from eliminating the gas line subsidies. As such, we find that the "economic effect of the terms and conditions upon projects, including redevelopment projects, funded or sponsored by cities, counties, or districts" to be higher costs for those projects that choose to connect to the gas system but offset (at least in part) by reduced gas rates, and also offset by the environmental and social benefits of ending gas line subsidies.

(5) The effect of the line and service extension regulations, and any modifications to them, on existing ratepayers.

The Commission estimates that the elimination of gas line subsidies for all new construction (residential and non-residential) will lead to an annual savings of approximately $164 million per year, as noted above. In addition to the ratepayer savings, other benefits to the ratepayers include reduction in GHG emissions and improving public health outcomes due to improved air quality. Thus, we find that the "effect of the line and service extension regulations, and any modifications to them, on existing ratepayers" is a savings of at least $164 million per year, plus additional environmental, social and health benefits.

(6) The effect of the line and service extension regulations, and any modifications to them, on the consumption and conservation of energy.

The Commission agrees with the Staff Proposal that the elimination of gas line subsidies for all new construction will result in less gas extensions, less gas consumption, and more electricity consumption.[130] This will also result in fewer GHG emissions and less air pollution. That is because electric generation is now produced by a substantial amount of non-GHG polluting power plants, and the

[130] Phase III Scoping Memo, Appendix A at 35, 40, and 44.

percentage of non-GHG producing power plants will increase over time as California meets its 100 percent clean electricity mandate of SB 100. With regard to energy conservation, to the extent elimination of these subsidies results in more all-electric construction, we agree with the Joint Parties that energy conservation will likely increase due to the efficiency of electric appliances.[131] Thus, we find the "effect of the line and service extension regulations, and any modifications to them, on consumption and conservation of energy" to be a reduction in gas consumption, an increase in electricity consumption, lower GHG emissions, less air pollution, and more energy conservation, with overall environmental, social and health benefits.

(7) The extent to which there is cost-justification for a special line and service extension allowance for agriculture.

The Commission find no impacts here as the proposal to eliminate gas line subsidies for all customer classes does not include special allowances for agricultural loads. No credible evidence was presented on a cost-justification, if any, for a special line and service extension allowance for agriculture.

Therefore, we conclude on these seven issues that the record in the proceeding provides the Commission sufficient basis to end gas line subsidies for all customer classes as this change is in California's best interest and is consistent with other Commission decisions and legislative intent. As attested by numerous parties, there are significant economy-wide climate, health, affordability, and equity benefits to eliminating gas line subsidies, in addition to the significant ratepayer savings as supported by the data in the Staff Proposal and the IOUs' ED-DR responses. In light of California's climate objectives and the importance of market signals to discourage further reliance on gas, we find that the benefits

[131] Opening Brief of Joint Parties at 22.

of ending these subsidies as discussed thoroughly in this decision outweigh any potentially negative economic effects to any particular customer classes described within these seven issues.

7.4.2. Compliance with Pub. Util. Code Section 783(c)

In compliance with Pub. Util. Code Section 783(c), the Phase III Scoping Memo requested the assistance and input of the agencies and departments included in the statute. The Commission served the Phase III Scoping Memo on these agencies and invited them to participate in this proceeding (*e.g.,* submit comments and reply comments on the Staff Proposal).[132] Additionally, on November 17, 2021, the assigned Commissioner sent a follow up e-mail to the Executive Directors (or an equivalent position) of these agencies and departments and invited them to provide input on the Staff Proposal by December 20, 2021. No comments or responses from the state agencies and state departments were received.

7.4.3. Compliance with Pub. Util. Code Section 783(d)

Lastly, the revisions to the gas rules adopted in this decision are effective July 1, 2023, consistent with Pub. Util. Code Section 783(d).

8. Conclusion

Based on the record and the analysis above, we conclude that, consistent with the policy objectives of this rulemaking and the state's climate goals, the current gas line subsidies for all customer classes should be eliminated, effective July 1 of the year following today's order pursuant to Pub. Util. Code Section 783(c), on July 1, 2023. We also adopt an application process through which the

[132] Phase III Scoping Memo at 1 and 12.

IOUs may seek gas line subsidies for individual projects meeting the criteria set out in this decision. This decision meets the statutory requirements as set forth in Pub. Util. Code Section 783(b)-(d).

9. Comments on Proposed Decision

The proposed decision of Commissioner Clifford Rechtschaffen in this matter was mailed to the parties in accordance with Pub. Util. Section 311 and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure (Rules). Comments were filed on August 30, 2022 by PG&E; SDG&E; SoCalGas; SCE; SWG; Clean Energy; the Joint Parties; SBUA; and The California Manufactures and Technology Association (CMTA). Reply comments were filed on September 6, 2022 by PG&E; SDG&E; SoCalGas; Clean Energy; the Joint Parties; SBUA; CMTA; and TURN.

Consistent with the Rules, we give no weight to comments that fail to focus on factual, legal, or technical errors (Rule 14.3(c)). In particular, we disregard comments that only reargue a party's position. In response to comments, we make the following revisions and clarifications:

- Corrections to non-substantive typographical errors and omissions.
- Clarification on the requirement of the IOUs, on behalf of the project applicant(s) seeking gas line subsidies, to demonstrate the factual basis for the project applicants' assertions, and confirm that the minimum requirements have been met based on the information provided by applicants.
- Removal of the requirement of the IOUs, on behalf of the project applicant(s) seeking gas line subsidies, to disclose all other incentives received by each project.

10. Assignment of Proceeding

Clifford Rechtschaffen is the assigned Commissioner and Scarlett Liang-Uejio and Ava Tran are the assigned ALJs in this proceeding.

Findings of Fact

1. The Commission initiated this proceeding to consider policy frameworks supporting decarbonization of buildings, including ongoing efforts to reduce GHG emissions associated with energy use in buildings.

2. The Phase I decision established the BUILD Program and the TECH Initiative pursuant to SB 1477.

3. The BUILD Program provides incentives to new residential housing projects that are all-electric and have no hookup to the gas distribution grid.

4. The TECH Initiative is a market transformation program providing incentives to advance the adoption of low-emission space and water hearing technologies.

5. The Phase II decision adopted: (a) guiding principles for the layering of incentives provided by multiple building decarbonization programs; (b) the WNDRR Program; (c) guidance on data sharing of customer and other information; and (d) requirements for the three large electric IOUs to conduct studies on bill impacts that result from fuel substitution for water heaters from natural gas to electric.

6. The Phase III Scoping Memo determined the issues to be resolved in Phase III including: (a) whether the Commission should modify or eliminate gas line extension allowances for some or all customer classes (residential and non-residential); (b) whether the Commission should modify or eliminate gas line extension refunds for some or all customer classes (residential and non-residential); and (c) whether the Commission should modify or eliminate

gas line extension discounts for some or all customer classes (residential and non-residential).

7. The Energy Division Staff Proposal recommends revisions to the current gas rules to eliminate the gas line subsidies for all customer classes effective July 1, 2023.

8. Of the parties commenting on eliminating the gas line subsidies for residential customers, there is wide support for the Staff Proposal among parties representing a substantial range of social, economic, and environmental interests.

9. Of the parties commenting on eliminating the gas line subsidies for non-residential customers, there is substantial support for the Staff Proposal among parties representing a wide range of interests.

10. The current gas line subsidies were established during a period when the state's energy needs and policy goals were very different from today's, and are no longer consistent with today's GHG emission reduction goals, the urgent need to reduce gas rates to ensure affordability, and the long term need to minimize future stranded investment.

11. The Commission adopted a uniform set of rules for gas utility line and service extensions beginning in 1915.

12. Under current rules, gas IOUs are not obligated to extend gas lines free of cost but must provide the opportunity for customers to be connected to the utility system at reasonable prices, terms, and conditions.

13. Current gas rules incentivize the installation of more gas appliances which perpetuate reliance on gas service and lock in all associated GHG emissions for the life of the appliance unless the appliance is retired early and replaced with an electric alternative.

14. The elimination of gas line subsides would make gas line and service extensions more expensive to the applicant for new gas service, and dual fuel new construction less desirable and financially riskier.

15. Eliminating gas line subsidies for all customer classes will result in significant ratepayer savings over the life of the gas line extensions.

16. Eliminating gas line subsidies for all customer classes is a logical step toward building decarbonization, consistent with state objectives and the Commission's policy frameworks. It will further the state's climate goals of reducing GHG emissions 40 percent by 2030 and achieving carbon neutrality by 2045 or sooner.

17. Eliminating gas line subsidies for all customer classes will improve overall quality of life (GHG emissions reductions, ratepayer savings, benefits to low income customers), and provide greater certainty for the builder community and the contractor community.

18. Eliminating gas line subsidies for all customer classes will result in a net positive impact on the workforce, as any potential decrease in demand for jobs within the gas industry is offset by the likely increase in demand for workers in several economic sectors, including in the electric industry, construction jobs for energy efficiency improvements and building retrofits.

19. Eliminating gas line subsidies for all customer classes does not remove customer choice as customers can continue to select their choice of fuel, with the difference being that existing and future gas customers will no longer have to subsidize investments in the gas infrastructure for new customers.

20. Eliminating gas line subsidies for all customer classes will not negatively impact energy reliability.

21. Eliminating gas line subsidies for all customer classes will have minimal impacts on property prices.

22. Eliminating gas line subsidies for all customer classes and supporting the hydrogen/RNG/CNG sector to reduce SLCPs can be successfully achieved together.

23. Large non-residential customers are the most significant contributors to GHG emissions.

24. There may be limited circumstances where gas line extensions for some non-residential projects can be beneficial, and gas line subsidies for these projects may be warranted.

25. Consideration of modifying or eliminating gas line subsidies is governed by Pub. Util. Code Section 783(b), which requires the Commission to make written findings on the following seven issues:

(a) The economic effect of the line and service extension terms and conditions upon agriculture, residential housing, mobile home parks, rural customers, urban customers, employment, and commercial and industrial building and development;

(b) The effect of requiring new or existing customers applying for an extension to an electrical or gas corporation to provide transmission or distribution facilities for other customers who will apply to receive line and service extensions in the future;

(c) The effect of requiring a new or existing customer applying for an extension to an electrical or gas corporation to be responsible for the distribution of, reinforcements of, relocations of, or additions to that gas or electrical corporation;

(d) The economic effect of the terms and conditions upon projects, including redevelopment projects, funded or sponsored by cities, counties, or districts;

(e) The effect of the line and service extension regulations, and any modifications to them, on existing ratepayers;

(f) The effect of the line and service extension regulations, and any modifications to them, on the consumption and conservation of energy; and

(g) The extent to which there is cost-justification for a special line and service extension allowance for agriculture.

26. Eliminating gas line subsidies will have the following impacts on the seven issues governed by Pub. Util. Code Section 783(b):

(a) The "economic effect of gas line and service extension terms and conditions upon agricultural, residential housing, mobile home parks, rural customers, urban customers, employment, and commercial and industrial building and development" will be overall net positive;

(b) The "effect of requiring new or existing customers applying for a gas line extension to provide transmission and distribution facilities to other customers who receive line and service extension in the future" will be limited to a shift in who pays which costs, will not be a material effect, and any negative effects on some customers, if any, will be offset by the overall positive effects of reducing GHG emissions, improved quality of life and health for customers, hundreds of millions of dollars in total ratepayer savings annually, greater equity for low-income customers, and greater certainty for the builder and contractor community;

(c) The "effect of requiring a new or existing customer applying for an extension to an electrical or gas corporation to be responsible for the distribution of, reinforcements of, relocations of, or additions to that gas or electrical corporation" will be that the new or existing customer will be responsible for and must pay the costs that are caused by that customer's line extension (including reinforcements, relocations, or additions). These costs will be outweighed by the economic and

environmental effects along with increased equity of having the cost-causer pay the costs that are incurred;

(d) The "economic effect of the terms and conditions upon projects, including redevelopment projects, funded or sponsored by cities, counties, or districts" will be higher costs for those projects that choose to connect to the gas system but will be offset (at least in part) by reduced gas rates, and also offset by the environmental and social benefits of ending gas line subsidies;

(e) The "effect of the line and service extension regulations, and any modifications to them, on existing ratepayers" will be savings of at least $164 million per year, plus additional environmental, social and health benefits;

(f) The "effect of the line and service extension regulations, and any modifications to them, on consumption and conservation of energy" will be a reduction in gas consumption, an increase in electricity consumption, lower GHG emissions, less air pollution, and more energy conservation, with overall environmental, social and health benefits; and

(g) There will be no "extent to which there is cost justification for a special line and service extension allowance for agriculture."

27. Pub. Util. Code Section 783(c) requires that:

The commission shall request the assistance of appropriate state agencies and departments in conducting any investigation or proceeding pursuant to subdivision (b), including, but not limited to, the Transportation Agency, the Department of Food and Agriculture, the Department of Consumer Affairs, the Bureau of Real Estate, and the Department of Housing and Community Development.

28. Pub. Util. Code Section 783(d) requires that:

Any new order or decision issued pursuant to an investigation or proceeding conducted pursuant to subdivision (b) shall become effective on July 1 of the year which follows the year

when the new order or decision is adopted by the commission, so as to ensure that the public has at least six months to consider the new order or decision.

29. During the course of this proceeding, the Commission provided notice and an opportunity to comment to those agencies identified in Pub. Util. Code Section 783(c).

Conclusions of Law

1. The Commission should eliminate gas line extension allowances, refunds, and discounts for all customer classes, with limited exceptions.

2. The Commission should allow limited exceptions to the elimination of gas line subsidies by permitting a utility to file an application for projects that meet specific criteria.

3. The application should be filed each year by July 1 and must demonstrate that each project meets the following criteria:

(a) The project shows a demonstrable reduction in GHG emissions;

(b) The project's gas line extension is consistent with California's climate goals, including those articulated in SB 32 (Pavley, 2016); and

(c) The project demonstrates that it has no feasible alternatives to the use of natural gas, including electrification.

4. The changes adopted in this decision to the gas rules comply with the statutory requirements of Pub. Util. Code Section 783(b)-(d).

5. The gas IOUs should each submit a Tier 2 AL to revise their gas line extension rules to eliminate gas line extension subsides in conformance with this decision. The revised rules should include the application process adopted in this decision allowing limited projects meeting the specific eligibility criteria set out in this decision to seek gas line extension allowances, refunds, and discounts.

O R D E R

IT IS ORDERED that:

1. Gas line extension allowances, the 10-year refundable payment option, and the 50 percent discount option in current utility gas line extension rules shall be eliminated, as provided below:

   (a) Gas Line Extension Allowances: All allowances set forth in utilities' Gas Rule Nos. 15 and 16 (for Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation) (collectively, the three gas utilities) and Gas Rule Nos. 20 and 21 (for Southern California Gas Company (SoCalGas)) shall be removed effective July 1, 2023, subject to the application process described in Ordering Paragraph (OP) 2 of this decision;

   (b) 10-Year Refundable Payment Option: All refunds set forth in utilities' Gas Rule Nos. 15 and 16 (for the three gas utilities) and Gas Rule Nos. 20 and 21 (for SoCalGas) shall be removed effective July 1, 2023, subject to the application process described in OP 2 of this decision; and

   (c) 50 Percent Discount Option: All discounts set forth in utilities' Gas Rule Nos. 15 and 16 (for the three gas utilities) and Gas Rule Nos. 20 and 21 (for SoCalGas) shall be removed effective on July 1, 2023, subject to the application process described in OP 2 of this decision.

2. Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Gas Company and Southwest Gas Corporation (collectively, the gas utilities) may request approval from the California Public Utilities Commission (Commission) by an annual application for a gas line extension allowance, a 10-year refundable payment option, or a 50 percent discount payment option (gas line subsidy) for specific, unique non-residential projects meeting the criteria established in this decision. For those eligible projects, the gas utility shall file an application with the Commission, on behalf of the

applicant(s), for approval of a gas line subsidy, by July 1 of each year starting in 2023. In its annual filing, each investor-owned gas utility shall include an update to the non-residential gas line extension allowance calculations based on the current methodology (including all inputs used, *e.g.*, cost of service factor). The criteria are:

(a) The project shows a demonstrable reduction in greenhouse gas emissions;

(b) The project's gas line extension is consistent with California's climate goals, including those articulated in Senate Bill 32 (Pavley, 2016); and

(c) The project demonstrates that it has no feasible alternatives to the use of natural gas, including electrification.

3. For those specific, unique non-residential projects where a gas line extension allowance, the 10-year refundable payment option, and the 50 percent discount payment option may still be warranted, the gas utilities, on behalf of the project applicants, shall demonstrate the factual basis for the project applicants' assertions, and confirm that the minimum requirements have been met based on the information provided by applicants before filing the annual application with the California Public Utilities Commission.

4. Within 30 days of the date of this order, Pacific Gas and Electric Company, Southern California Gas Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall each submit a Tier 2 Advice Letter to revise tariffs for their respective gas line extension rules that eliminate gas line extension subsides in conformance with this decision. The revised tariffs shall include the application process adopted in this decision allowing limited projects meeting the specific eligibility criteria set out in this decision to seek gas line extension allowances, 10-year refunds, or 50 percent discounts payment option.

5. Rulemaking 19-01-011 remains open.

This order is effective today.

Dated September 15, 2022, at Clovis, California.

ALICE REYNOLDS
President
CLIFFORD RECHTSCHAFFEN
GENEVIEVE SHIROMA
DARCIE L. HOUCK
JOHN REYNOLDS
Commissioners

Docket No. UG 490
R.19-01-011 COM/CR6/nd3

APPENDIX A
Abbreviations, Acronyms, and Definitions

APPENDIX A

Abbreviations, Acronyms, and Definitions

A.	Application
ALJ	Administrative Law Judge
Allowances	Gas line extension allowances
Applicant	An entity (e.g., builder, developer, individual customer) who seeks connection to the utility system
AL	Advice Letter
April 18, 2022 ALJ Ruling	An ALJ ruling receiving into the evidentiary record the gas utilities' responses to the ED-DR
BUILD Program	Building Initiative for Low Emissions Development Program.
Cal Advocates	The Public Advocates Office of the Commission
CARB	California Air Resources Board
CCUE	Coalition of California Utility Employees
Commission	California Public Utilities Commission
CEC	California Energy Commission
CEJA	California Environmental Justice Alliance
CNG	Compressed Natural Gas
DCA	California Department of Consumer Affairs
DRE	California Department of Real Estate
EBCE	East Bay Community Energy
ED-DR	A March 14, 2022, Energy Division data request (ED-DR) sent to PG&E, SoCalGas, SDG&E and SWG; directed the gas utilities to verify and serve their responses to the ED-DR on all parties
EDF	Environmental Defense Fund
FY	Fiscal Year
GHG	Greenhouse Gas
Gas Line Subsidies	Gas line extension allowance, 10-year refundable payment option, or 50 percent discount payment option
Gas Rules	Gas line extension rules:

	Gas Rules 15-16 for PG&E (https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS_RULES_15.pdf, https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS_RULES_16.pdf), SDG&E (https://tariff.sdge.com/tm2/pdf/GAS_GAS-RULES_GRULE15.pdf, https://tariff.sdge.com/tm2/pdf/GAS_GAS-RULES_GRULE16.pdf), and SWG (https://www.swgas.com/1409184638489/rule15.pdf, https://www.swgas.com/1409184638517/RULE_16--GRC_Eff-April-1-2021.pdf), and Gas Rules 20-21 for SoCalGas (https://tariff.socalgas.com/regulatory/tariffs/tm2/pdf/20.pdf, https://tariff.socalgas.com/regulatory/tariffs/tm2/pdf/21.pdf). Rule 15/20 pertains to gas distribution main extensions and Rule 16/21 pertains to gas service line extensions.
HCD	California Department of Housing and Community Development
IOUs	Investor-owned utilities
Joint CCAs	EBCE, Marin Clean Energy, Peninsula Clean Energy, and Sonoma Clean Power
Joint IOUs	Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Gas Company
Joint Parties	California Environmental Justice Alliance, Environmental Defense Fund, Natural Resources Defense Council, and Sierra Club
MCE	Marin Clean Energy
NRDC	Natural Resources Defense Council
OIR	Order Instituting Rulemaking
OP	Ordering Paragraph
PCE	Peninsula Clean Energy
PG&E	Pacific Gas and Electric Company
Phase I Decision	D.20-03-027 established the two building decarbonization pilot programs required by SB 1477: the BUILD Program and the TECH Initiative.
Phase II Decision	D.21-11-002 (1) adopted guiding principles for the layering of incentives when multiple programs fund the same equipment; (2) established the WNDRR Program to provide financial incentives to help victims of wildfires and natural disasters rebuild all-electric properties; (3) provided guidance on data sharing; and (4) directed California's three large electric investor-owned utilities (IOUs)

Phase III Scoping Memo	An Amended Scoping Memo and Ruling setting forth the issues to be considered in Phase III of this proceeding issued on November 16, 2021.
Pub. Util. Code	Public Utilities Code
R.	Rulemaking
RNG	Renewable Natural Gas
SCE	Southern California Edison Company
SCP	Sonoma Clean Power
SB	Senate Bill
SBUA	Small Business Utility Advocates
SDG&E	San Diego Gas & Electric Company
SLCPs	Short Lived Climate Pollutants
SoCalGas	Southern California Gas Company
Staff Proposal	Staff Proposal on Phase III issues (Appendix A, Phase III Scoping Memo).
SWG	Southwest Gas Corporation
TECH Initiative	Technology and Equipment for Clean Heating Initiative.
TURN	The Utility Reform Network
WNDRR Program	Wildfire and Natural Disaster Resiliency Rebuild Program

(END OF APPENDIX A)

Service Date: October 29, 2021

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of Chair Danner's Motion to Consider Whether Natural Gas Utilities Should Continue to Use the Perpetual Net Present Value Methodology to Calculate Natural Gas Line Extension Allowances	DOCKET UG-210729 ORDER 01 AUTHORIZING AND REQUIRING TARIFF REVISIONS

INTRODUCTION

1 **PROCEDURAL HISTORY.** On September 21, 2021, the Washington Utilities and Transportation Commission (Commission) issued a Notice of Item to be Considered at the Commission's Regularly Scheduled Open Meeting and Notice of Opportunity to File Written Comments (Notice). The Notice explained that Commission Chair David Danner, on his own motion, seeks input from regulated natural gas companies and stakeholders addressing whether natural gas utilities should continue to use the current Perpetual Net Present Value (PNPV) methodology for calculating natural gas line extension allowances.

2 The Notice explained that the Commission would address this issue at its October 28, 2021, regularly scheduled open meeting and requested that interested persons file written comments by October 25, 2021.

3 **BACKGROUND.** Natural gas utilities provide line extension allowances to partially offset the cost of expanding the natural gas distribution system to new customers. In 2014, the Commission opened Docket UG-143616 to discuss the need for natural gas distribution infrastructure expansion as well as the options available to implement such an expansion. Part of that discussion included adopting the PNPV methodology,[1] which significantly increased the credit provided to customers through natural gas line extension allowances.

4 On February 25, 2016, Avista Corporation d/b/a Avista Utilities (Avista) proposed tariffs adopting the PNPV method for calculating line extension allowances. The Commission

[1] Under the PNPV method, a line extension allowance is calculated using the anticipated revenue from the customer divided by the authorized rate of return, which results in the net present value of the customer's presence on the system. The current calculation assumes that a customer will remain on the natural gas system in perpetuity. See Commission Staff's Comments, page 1-2.

authorized the change and increased Avista's natural gas line extension allowance from $1,920 to $4,482 for residential customers. The PNPV method for calculating Avista's natural gas line extensions was made permanent on February 19, 2019.[2]

5 On July 29, 2016, Cascade Natural Gas Corporation (Cascade) filed proposed revisions to its Tariff WN U-3 that adopted the PNPV method to calculate line extension allowances. This change increased the company's line extension allowance from $572 to $3,255 for residential customers. The tariff revisions became effective by operation of law on September 1, 2016.[3]

6 On December 6, 2016, Puget Sound Energy (PSE) filed a tariff revision proposing to implement Rule No. 6 – Extension of Distribution Facilities, which adopted the PNPV methodology consistent with Avista's and Cascade's line extension tariffs. This change increased PSE's natural gas line extension allowance from $1,932 to $4,179 for residential customers. The Commission authorized the tariff change at its January 12, 2017, open meeting.[4]

7 In PSE's 2019 General Rate Case, the Commission received testimony from the Northwest Energy Coalition (NWEC) noting that the current PNPV calculation can result in subsidies from current natural gas customers to new customers and recommending that the Commission require PSE to revert to its previous line extension allowance calculation methodology or to revisit the issue in a broader forum. The Commission declined to adopt NWEC's recommendation as part of that rate case but signaled its intention to revisit the issue in a future proceeding.[5] Chair Danner dissented from this decision. In a concurring statement, Commissioner Rendahl supported revisiting the issue because the record evidence in the rate case was insufficient to support making a change.

8 **STAKEHOLDER COMMENTS.** The Commission received written comments from numerous stakeholders, including Commission staff (Staff). Most comments recommend discontinuing natural gas line extension allowances entirely or at least discontinuing the use of the PNPV methodology. The Alliance of Western Energy Consumers (AWEC) filed comments recommending the Commission retain the PNPV methodology, but later revised its comments at the open meeting to support Staff's or Northwest Natural Gas Company's proposals.

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[2] Docket UG-152394, Staff Memo (Feb. 25, 2016).

[3] Docket UG-160967, Staff Memo (Aug. 29, 2016).

[4] Docket UG-161268, Staff Memo (July 10, 2017).

[5] Docket UE-190529 *et. al.*, Final Order 08 ¶ 614 (July 8, 2020).

9 The City of Seattle urged the Commission to consider the costs of expanding fossil fuels, including the social cost of greenhouse gas, and whether benefits would still accrue for ratepayers, including low-income and vulnerable customers.

10 The Public Counsel Unit of the Attorney General's Office (Public Counsel) recommends the Commission discontinue the use of PNPV and provide line extension allowances that minimize the socialized costs of line extensions while still providing adequate access to natural gas for new customers. At the open meeting, Public Counsel noted that reducing the use of natural gas is consistent with legislative clean energy goals and recommended the Commission adopt an alternative to PNPV that is consistent with Washington state clean energy policy.

11 Avista supports discontinuing the use of the current PNPV methodology and reverting to its prior methodology, or, in the alternative, adopting Staff's recommendation. Avista proposes to use values from its Natural Gas Decoupling Mechanism baseline to determine the natural gas line extension allowance, resulting in an allowance for residential customers of $2,100 (compared to the present allowance of $4,678) and a Non-Residential per therm allowance of $1.36/therm (compared to the present allowance of $3.44/therm). At the Commission's open meeting, Avista stated that it has 272 customers currently under construction and receiving line extension allowances and more than 1,000 customers in the design phase. Avista thus requests a transition date of April 1, 2022, to allow customers who have already begun the line extension process to move forward under the current PNPV calculation.

12 Northwest Natural Gas Company (NW Natural) does not currently use PNPV. Rather, NW Natural calculates its line extension construction allowance as five times the delivery margin for the applicable rate schedule multiplied by the annual estimated therm usage attributable to the customer's installation. NW Natural believes that its existing Schedule E tariff is designed to determine the fair cost of providing fuel choice while economically eliminating cross-subsidization between existing ratepayers and new customers.

13 PSE supports discontinuing the PNPV methodology because it is increasingly out of step with the evolution of the State's energy policy. PSE supports a methodology that reasonably ensures existing natural gas customers are not subsidizing the connection of new natural gas customers and better aligns with both Washington's and PSE's decarbonization goals. To that end, PSE believes that promptly reverting to something like its previous methodology for determining natural gas line extension allowances may be appropriate. PSE's previous line extension allowance used a discounted cash flow

Facilities Investment Analysis (FIA) methodology.[6] PSE supports immediately changing back to the FIA methodology in the interim and addressing this issue more fully in Docket U-210553, the Commission's examination of energy decarbonization impacts and pathways for electric and gas utilities to meet state emissions targets. At the Commission's open meeting, PSE reiterated its recommendation to conduct a broader investigation into this issue and stated that it supports Staff's recommendation.

14 The Department of Commerce (Commerce) asserts that PNPV is contrary to state policy and urges the Commission to consider discontinuing line extension allowances altogether. In the alternative, Commerce supports Staff's recommendation to modify the PNPV calculation.

15 RMI and the Natural Resources Defense Council observe that the line extension allowances generated by the PNPV method are 1.5 to 3 times higher than allowances in Colorado and California, both of which use revenue-based formulas to calculate allowances.

16 Cascade proposes reverting to its previous calculation method of 3.3 times margin allowance for service connections and an additional 3.3 times margin allowance if main extensions are also required. Cascade proposes a transition period to allow the company to complete line extensions already in progress using the current PNPV method.

17 350Seattle recommends ending all natural gas line extension allowances and instead providing allowances for beneficial electrification.

18 The Sierra Club urges the Commission to implement a complete moratorium on new natural gas collections or, in the alternative, to end natural gas line extension allowances.

19 NWEC recommends the Commission evaluate and potentially discontinue line extension allowances completely. NWEC further recommends the Commission evaluate the need for regulatory tools for natural gas utilities to meet state greenhouse gas emission reduction targets.

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[6] The FIA methodology provides a line extension allowance based on a calculation that includes, for example, consideration of the natural gas powered appliances being installed, annual therm assumptions estimated using square footage, whether a main extension is required, and whether other new customers would be included along the same extension the FIA methodology does allow more precise assumptions that can be tailored to reflect current state policy including building codes and to align with PSE's decarbonization goals.

20 The 37th Legislative District Democratic Environmental Caucus recommends discontinuing the use of PNPV or any rate-based fees for extending natural gas distribution infrastructure.

21 Staff recommends retaining the PNPV method but updating the discount timeframe as a matter of policy. Overall, Staff believes this revised PNPV method results in a simpler tariff structure and makes the relevant calculations easier to understand, perform, and apply. Staff also believes that this PNPV method ensures that line extension allowances are economically justified. Staff recommends adopting a Net Present Value (NPV) method that updates the discount timeframe based on consideration of the following policy factors:

- Cost of greenhouse gas emissions
- Environmental impact from oil furnaces and wood-burning stove emissions
- Economic development from expanding service to areas not currently served by natural gas
- Increasing energy efficiency
- Historical equity in access to natural gas for marginalized communities and vulnerable populations
- The treatment of natural gas versus electric infrastructure by the State of Washington

22 Staff recommends using an eight-year timeframe because it aligns the margin allowance discount timeframe with the implementation of the Clean Energy Transformation Act (CETA).[7] Additionally, Staff believes that a calculation using the 8-year timeframe will be closer to or lower than an updated margin allowance calculation using PSE's FIA model.

23 Chair Danner proposes to adopt Staff's recommendation, in part, and modify the PNPV method to include a timeline of seven years, which will result in a limited line extension allowance more consistent with state policy and closer to the amount allowed in 2014 prior to the adoption of PNPV.

[7] Chapter 19.405 RCW.

DISCUSSION AND DECISION

24 We agree with Staff's recommendation, in part, and require PSE, Avista, and Cascade to file tariff revisions by November 17, 2021, adopting a Net Present Value (NPV) methodology using a seven-year timeline for calculating natural gas line extension allowances for the reasons discussed below.

25 In recent years, the legislature has enacted several laws aimed at reducing greenhouse gas emissions, including emissions from natural gas. In 2019, the legislature passed CETA, which requires electric utilities to eliminate coal by 2025 and all carbon-emitting resources by 2045. In 2021, the legislature amended RCW 80.28.074 to clarify that advancing the availability of natural gas services to Washington residents is no longer state policy. Additionally, as several commenters noted, the legislature directed that Washington's energy code be revised to make new construction more efficient, which will result in new homes and buildings using less natural gas than existing structures currently use.

26 Further, this year, the legislature also passed the Climate Commitment Act,[8] under which gas companies must meet specific emissions reductions requirements and must surrender allowances to cover the greenhouse gas emissions from the use of their product. While gas companies will receive free emissions allowances to address cost impacts to current customers, almost all new customers are excluded from this part of the program.

27 We appreciate the thoughtful perspectives offered by the companies, consumers, and stakeholders, most of whom agree that the current PNPV methodology is contrary to the legislature's clear direction to reduce greenhouse gas emissions and the use of fossil fuels. As many commenters aptly observed, it is imperative that we address climate change, including the health impacts of greenhouse gases and methane emissions on Washington's communities and citizens. Recognizing the urgency of this issue, we view our decision today as an interim measure that will substantially reduce line extension allowances while we continue to engage in dialogue with regulated utilities and other stakeholders in Docket U-210553, the Commission's broader examination of energy decarbonization impacts and pathways for electric and gas utilities to meet state emissions targets.

28 The comments we received in this docket offer several important factors to consider as we move forward, including the likelihood that natural gas lines will not be serving customers in Washington in perpetuity, the laws and rules in Washington related to greenhouse gas emissions, new requirements in the State Energy and Building Codes,

[8] RCW 70A.65.900.

ensuring that utility tariffs do not increase the likelihood of stranded assets in the future, and ensuring that line extension policies do not shift the cost burden from new to current customers. Although the proceeding in Docket U-210553, which is already underway, provides a more appropriate forum to ensure that these factors are thoroughly considered, we conclude that discontinuing use of the current PNPV calculation immediately is in the public interest because it can result in existing customers subsidizing new customers while significantly increasing reliance on fossil fuels. Given the recent changes to laws and policies discussed above, we conclude that the current PNPV calculation is no longer a valid line extension allocation method for Washington utilities or their customers.

29 Accordingly, we agree Staff's recommendation and require PSE, Avista, and Cascade to adopt an NPV calculation for natural gas line extension allowances. This methodology is simple to calculate because it requires a single assumption — the length of time the service will be installed — and relies on information from recent rate cases. Imposing a seven-year calculation timeline will reduce the line extension allowance for the residential customers of each company to approximately $2,000, which is a substantial, but gradual, decrease from current values.

30 Finally, Avista, Cascade, and PSE request that we provide a transition period for customers who have received approval for a line extension allowance under the current tariff. We agree that the companies should be authorized to exempt from the new tariff provisions those customers who have submitted applications that are approved or pending as of the date the revised tariffs become effective, as well as those customers who can demonstrate or attest that their applications have been submitted to local permitting offices. This exemption will expire on April 1, 2022.

FINDINGS AND CONCLUSIONS

31 (1) The Commission is an agency of the State of Washington, vested by statute with authority to regulate rates, rules, regulations, practices, and accounts of public service companies, including natural gas companies, and has jurisdiction over the parties and subject matter of this proceeding.

32 (2) PSE, Avista, and Cascade are natural gas companies subject to Commission regulation.

33 (3) This matter came before the Commission at its regularly scheduled open meeting on October 28, 2021.

34 (4) The PNPV methodology currently in effect for calculating natural gas line extension allowances significantly increases the margin allowances for each utility and thus increases reliance on fossil fuels contrary to state policy and laws.

38 (5) The NPV methodology proposed by Staff and calculated using a seven-year timeline provides a substantial but gradual decrease in natural gas line extension allowances that is better aligned with the legislature's direction and policy goals and is therefore in the public interest.

39 (6) The Commission should require PSE, Avista, and Cascade to file by November 17, 2021, tariff revisions that reflect the use of the NPV methodology using a seven-year timeframe for calculating natural gas line extension allowances.

ORDER

THE COMMISSION ORDERS THAT:

35 (1) Puget Sound Energy, Avista Corporation d/b/a Avista Utilities, and Cascade Natural Gas Corporation are required and authorized to file by November 17, 2021, tariff revisions necessary and sufficient to effectuate the terms of this Order.

36 (2) The Commission retains jurisdiction to effectuate the terms of this Order.

DATED at Lacey, Washington, and effective October 29, 2021.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DAVID W. DANNER, Chair

ANN E. RENDAHL, Commissioner

Service Date: December 12, 2022

**BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. AVISTA CORPORATION, d/b/a AVISTA UTILITIES, Respondent	DOCKETS UE-220053, UG-220054, UE-210854 *(Consolidated)* FINAL ORDER 10/04
In the Matter of the Electric Service Reliability Reporting Plan of AVISTA CORPORATION, d/b/a AVISTA UTILITIES.	REJECTING TARIFF SHEETS; GRANTING PETITION; APPROVING AND ADOPTING FULL MULTIPARTY SETTLEMENT STIPULATION SUBJECT TO CONDITIONS; AUTHORIZING AND REQUIRING COMPLIANCE FILING

Synopsis: *The Washington Utilities and Transportation Commission (Commission) approves and adopts subject to conditions a full multiparty settlement stipulation (Settlement) that resolves all contested issues and is agreed to by all Parties except the Public Counsel Unit of the Washington Attorney General's Office (Public Counsel), which contests some portions of the Settlement.*

Public Counsel opposes the Settlement's resolution of power costs, insurance expense balancing account, wildfire-related issues, cost of capital, and the overall revenue requirement, but either supports or does not oppose all other terms of the Settlement, including: cost of service, rate spread, and rate design; the Residual Tax Customer Credit; Colstrip investments, tracker, and Tariff Schedule 99; the escalation study; capital planning; distributional equity analysis; capital projects review; natural gas transition issues; transportation electrification; performance-based ratemaking; low-

income issues; the Climate Commitment Act; small business energy efficiency; electric service reliability report plan; depreciation rates and regulatory amortizations; annual filing dates; annual reporting obligations of Docket U-210151; software licensing; and the decoupling earnings test.

The Commission finds that the Settlement is lawful, supported by an appropriate record, and consistent with the public interest, subject to the conditions outlined in paragraphs 78, 85, 99, 112, and 146 of this Order. Accordingly, the Commission determines that approval of the Settlement, subject to conditions and in concert with other findings, will establish rates, terms, and conditions for Avista's electric and natural gas service to Washington customers that are equitable, fair, just, reasonable, and sufficient.

The Settlement is results-focused and provides a results-only resolution for Avista's overall revenue requirement.[1]

By approving the Settlement, the Commission authorizes revenue requirement increases for Avista over a multi-year rate plan (MYRP) covering the upcoming two-year period. The Settlement returns Residual Tax Customer Credit amounts of approximately $27.6 million and $12.5 million to electric and natural gas customers, respectively, over the term of the MYRP. Prior to the impact of the Residual Tax Customer Credit, the Settlement provides a $38.0 million annual increase to the Company's electric revenues, and a $7.5 million in natural gas revenues in Rate Year 1, and, in Rate Year 2, an additional increase of $12.5 million to the Company's electric revenues, and $1.5 million in natural gas revenues.

As a result of the Settlement, a typical residential electric customer using 932 kWhs per month will pay $4.47 more per month in Rate Year 1, for an average monthly bill of $89.99, and a typical residential electric customer using 932 kWhs per month will pay $2.24 more per month in Rate Year 2, for an average monthly bill of $92.23. A typical residential natural gas customer using 67 therms per month will pay $0.20 more per month in Rate Year 1, for an average monthly bill of $65.06; and a typical residential natural gas customer using 67 therms per month will pay $0.52 more per month in Rate Year 2, for an average monthly bill of $65.58.

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[1] The Commission is working to adopt more inclusive language in its documents, and therefore describes a settlement as "results-focused" or "results-only" when underlying components of a settlement are not enumerated or supported by calculations. We encourage all investor-owned utilities, parties to proceedings, and interested persons to do the same. Please refer to footnote 239 for a more detailed explanation.

Other noteworthy terms the Commission approves as part of the Settlement include the establishment of a new Tariff Schedule 99 (the Colstrip Tracker) with an annual true-up to separately track and recover certain costs related to the Colstrip generating plant.

The Commission's approval of the Settlement also results in the historic first set of performance metrics (Attachment B to the Settlement and two metrics related to transportation electrification plus the commitment to develop additional reliability metrics) that will track data agreed to by the Settling Parties related to Avista's performance during the MYRP. The results of these metrics will be published, maintained, and tracked on Avista's website for public access and reported to the Commission. The metrics will be reported on either a quarterly or annual basis beginning 45 days after the end of the first quarter of 2023.

In addition to approving the Settlement, the Commission fulfills its obligation under RCW 80.28.425(7) to determine a set of performance measures to use in assessing Avista's operations during the MYRP. In particular, the Commission adopts nine performance measures related to operational efficiency, earnings, affordability, and energy burden for the purpose of assessing how much expense Avista incurs for every dollar it earns; the efficient use of Avista's assets to generate revenue, maintaining liquidity; how much net profit Avista gains through the revenues it earns; the amount of earnings retained by Avista vis-à-vis its total equity; and tracking affordability for, and the energy burden of, residential customers.

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BACKGROUND

1 This case concerns Avista Corporation's d/b/a Avista Utilities (Avista or Company) 2022 electric and natural gas general rate case (GRC) and its electric service reliability reporting plan.

2 On November 11, 2021, Avista filed with the Washington Utilities and Transportation Commission (Commission) its Electric Service Reliability Reporting Plan in Docket UE-210854 pursuant to Washington Administrative Code (WAC) 480-100-393, modifying its previous plan.

3 On January 21, 2022, Avista filed with the Commission revisions in Docket UE-220053 to its currently effective electric service tariff, Tariff WN U-28, and in Docket UG-220054 to its natural gas service tariff, Tariff WN U-29 (Avista 2022 GRC). The Company proposed a two-year rate plan with increases for electric and natural gas operations for Rate Year 1 effective December 21, 2022, and for Rate Year 2 effective December 21, 2023, as depicted in Table 1, below.

4 Concurrent with the effective date of its 2022 GRC, Avista proposes to partially offset the Company's requested increases, and return to customers the estimated incremental customer tax Accumulated Deferred Income Tax (ADIT) benefits of approximately $25.5 million for electric and $12.5 million for natural gas over a two-year amortization period through separate Tariff Schedules 78 (electric) and 178 (natural gas).[2] We refer to this return of tax benefits as the "Residual Tax Customer Credit" throughout this Order.[3] Rate Year 1 rates are offset by this tax credit to result in an increase of 7.4 percent to *billed* rates for electric operations and 2.5 percent for natural gas operations.[4] Rate Year 2 rates, as proposed by Avista, already embed the tax credit in base rates, but Avista notes that the resulting increase to *billed* rates is 3.0 percent for electric operations and 1.1 percent for natural gas operations.[5]

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[2] Andrews, Exh. EMA-1T at 5:29-6:7. The amount of ADIT benefits to be returned to customers was updated during these consolidated proceedings to $27.6 million for electric.

[3] Avista refers to this return of tax benefits as the "Tax Customer Credit" under its initial proposal. Vermillion, Exh. DPV-1T at 18:18-23.

[4] *Id.* at 18:23-19:14.

[5] *Id.* at 19:5-14; *see* Avista Electric Summaries for Rate Year 1 & Rate Year 2 (filed Mar. 28, 2022) and Natural Gas Summaries for Rate Year 1 & Rate Year 2 (filed Jan. 21, 2022).

5 **Table 1. Avista's Initial Proposal for Net Revenue Increases *(in millions)***

	Electric		Natural Gas	
Rate Year 1	$ 52.9	9.6%	$ 10.9	9.5%
Residual Tax Customer Credit[6]	$ (12.8)		$ (6.3)	
Net Increase	**$ 40.1**	**7.4%**	**$ 4.6**	**2.5%**
Rate Year 2	$ 17.1	2.8%	$ 2.2	1.7%
Residual Tax Customer Credit[7]	$ (0.0)		$ (0.0)	
Net Increase	**$ 17.1**	**2.8%**	**$ 2.2**	**1.7%**

6 On January 27, 2022, the Commission entered Order 01, consolidating Dockets UE-220053 and UG-220054, suspending the tariff revisions, and setting the matters for adjudication.

7 The Commission entered a Protective Order, Order 02, in Dockets UE-220053 and UG-220054 *(Consolidated)* on January 31, 2022.[8]

8 On February 14, 2022, the Commission convened a virtual prehearing conference before Administrative Law Judge Andrew J. O'Connell.

9 On February 16, 2022, the Commission issued Order 03, Prehearing Conference Order; Notice of Hearing, adopting with minor modifications the agreed procedural schedule and setting a hearing to begin on September 21, 2022. Order 03 also granted intervention to the Alliance of Western Energy Consumers (AWEC), the NW Energy Coalition (NWEC), The Energy Project (TEP), Sierra Club, and Small Business Utility Advocates (SBUA).

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[6] Amortized over two years, Avista's initial proposal for the Residual Tax Customer Credit of approximately $25.5 million for electric would result in approximately $12.8 million annually, and of approximately $12.5 million for natural gas would result in approximately $6.3 million annually.

[7] Amortization of the Residual Tax Customer Credit is embedded in year two base rates.

[8] The Commission would later consolidate these dockets with Docket UE-210854 by Order 07/01.

10 On February 16, 2022, Walmart, Inc., (Walmart) filed a late-filed petition to intervene.

11 On February 28, 2022, the Commission convened a second virtual prehearing conference to address processes, procedures, and applications for participatory funding. Pursuant to RCW 80.28.430, utilities must enter into funding agreements with organizations that represent broad customer interests. The Commission is directed to determine the amount of financial assistance, if any, that may be provided to any organization; the way the financial assistance is distributed; the way the financial assistance is recovered in a utility's rates; and other matters necessary to administer the agreement.[9]

12 The Commission's Policy Statement on Participatory Funding for Regulatory Proceedings (Policy Statement) provides "high-level guidance regarding the amount of financial assistance that may be provided to organizations, the manner in which it is distributed to participants and recovered in the rates of gas or electrical companies, and other matters necessary to administer agreements."[10] In Docket U-210595, the Commission approved and adopted an interim agreement on participatory funding, subject to certain modifications.[11]

13 On March 1, 2022, the Commission entered Order 04, Second Prehearing Conference Order, granting Walmart's unopposed late-filed petition to intervene and adopting the schedule discussed at the February 28, 2022, conference. Order 04 required organizations seeking a fund grant to file a request for case certification and notice of intent to request a fund grant by March 9, 2022.

14 By March 9, 2022, AWEC, TEP, NWEC, and SBUA had each filed with the Commission a request for case certification and notice of intent to request a fund grant.

15 On March 16, 2022, the Commission issued a Notice of Bench Requests Nos. 1 and 2, requesting additional information relevant to participatory funding from NWEC, TEP, and SBUA. NWEC, TEP, and SBUA each filed its response with the Commission on March 18, 2022.

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[9] RCW 80.28.430(2).

[10] *In re Examination of Participatory Funding Provisions for Regulatory Proceedings,* Docket U-210595, Policy Statement, ¶ 3 (Nov. 19, 2021) [hereinafter Participatory Funding Policy Statement].

[11] *In re Petition of Puget Sound Energy, et al.*, Docket U-210595, Order 01 (Feb. 24, 2022).

16 On March 24, 2022, the Commission entered Order 05, Granting Requests for Case Certification. Order 05 granted case certification to AWEC, NWEC, TEP, and SBUA, and directed each to file a proposed budget within 30 days.

17 AWEC, TEP, NWEC, and SBUA all timely filed with the Commission proposed budgets by April 25, 2022.

18 On May 27, 2022, the Commission entered Order 06, Approving and Rejecting Proposed Budgets for Fund Grants. Order 06 approved the proposed budgets of AWEC, NWEC, and TEP, but rejected the proposed budget of SBUA, finding that SBUA failed to establish a sufficient connection to Washington ratepayers.

19 Also on May 27, 2022, the Commission entered Order 07/01, consolidating Dockets UE-220053 and UG-220054 with Docket UE-210854 pursuant to Commission staff's (Staff) unopposed motion to consolidate.

20 On June 6, 2022, SBUA filed with the Commission a petition for interlocutory review, requesting the Commission modify Order 06 and approve SBUA's proposed budget.

21 On July 11, 2022, the Commission entered Order 08/02, Granting Petition for Interlocutory Review, In Part; Approving Proposed Budget Subject to Condition (Order 08). Order 08 approved SBUA's proposed budget in the amount of $20,000 to be used for attorney fees and expert witness fees only, subject to the condition that SBUA file a confidential list of its members concurrent with its request for reimbursement later in these consolidated proceedings.[12]

22 On June 13, 2022, the Commission suspended the procedural schedule in these consolidated matters pursuant to a joint request from the parties, indicating that the parties had reached a full multiparty settlement.

23 On June 22, 2022, the Commission issued a Notice Adopting Agreed Procedural Schedule and Notice of Hearing, setting a virtual hearing on the full multiparty settlement

[12] Order 08 found that requiring the confidential submission of its membership list is neither unusual nor extraordinary, observing that other organizations have provided confidential membership lists in other proceedings and would assist the Commission with evaluating SBUA's connection to Washington ratepayers (citing AWEC's confidential filing of its membership lists in Cascade Natural Gas Corporation's general rate case, Docket UG-210755, in support of its proposed budget and in Puget Sound Energy's general rate case, Dockets UE-220066 and UG-220067 *(Consolidated)*, in support of its petition to intervene). Order 08 at 6, ¶ 20, n. 4.

for September 21, 2022. Avista, Staff, AWEC, NWEC, TEP, Sierra Club, SBUA, and Walmart (Settling Parties) agreed to the full multiparty settlement.

24 On June 28, 2022, the Settling Parties filed with the Commission their Full Multiparty Settlement Stipulation (Settlement). The Settlement and Attachment A to the Settlement are attached to this Order as Appendix A.

25 On July 8, 2022, the Settling Parties filed with the Commission their joint testimony in support of the Settlement.

26 On July 29, 2022, the Settling Parties filed with the Commission their supplemental joint testimony in support of the Colstrip Tracker and Tariff Schedule 99, one of the items addressed by the Settlement.

27 Also on July 29, 2022, the Public Counsel Unit of the Washington Attorney General's Office (Public Counsel) filed with the Commission its testimony opposing the Settlement.

28 On August 19, 2022, Avista filed with the Commission rebuttal testimony responding to Public Counsel's opposition testimony.

29 On September 7, 2022, the Commission issued Order 09/03, granting an unopposed motion by Avista to revise Attachment C to the Settlement.

30 Also on September 7, 2022, the Commission held a virtual public comment hearing in these consolidated matters. No person offered comments.

31 On September 21, 2022, the Commission held a virtual settlement hearing and received testimony from a panel of witnesses representing the Settling Parties and Avista witnesses. At the hearing, the parties stipulated to the admission of all exhibits into the record. Due to time constraints, the Commission continued a portion of the hearing until a later date.

32 On September 23, 2022, the Commission issued a notice reconvening the virtual settlement hearing for September 30, 2022, to receive testimony from Avista witnesses whose testimony could not be heard on September 21, 2022.

33 On September 30, 2022, the Commission reconvened the virtual settlement hearing and received all remaining testimony from witnesses.

34 On October 14, 2022, Public Counsel filed with the Commission its response to Bench Request No. 3, which contained all public comments received in these consolidated dockets. Over the course of the proceeding, including the public comment hearing, the Commission and Public Counsel received 30 comments from Washington customers regarding the proposed rate increases. All comments opposed a rate increase.[13] The comments focused on a variety of topics, including the unaffordability of residential rates (especially for those on fixed incomes), insufficient or inadequate programs, and rate design.[14]

35 On October 20, 2022, Avista filed with the Commission its responses to Bench Requests Nos. 4-6, which regarded details of how the Residual Tax Customer Credit was to be passed back to customers during the proposed two-year rate plan, the cumulative impact on net plant balances related to removing Colstrip Dry Ash from Rate Year 1 and Rate Year 2, and the resulting monthly bill for average electric and natural gas residential customers if the Settlement were approved, respectively.

36 On October 21, 2022, Avista, Staff, Public Counsel, AWEC, NWEC, TEP, and SBUA filed post-hearing briefs with the Commission. Walmart filed a letter with the Commission indicating it would not file a post-hearing brief.

37 Also on October 21, 2022, Avista filed with the Commission its 2022 Draft Electric Service Reliability Reporting Plan for informational purposes.

38 On November 23, 2022, Avista filed with the Commission its response to Bench Request No. 7 related to the Settling Parties' reference to Avista's updated cost of debt during the pendency of these consolidated proceedings and the source material for that update.

39 David J. Meyer, Vice President and Chief Counsel for Regulatory and Governmental Affairs, Spokane, Washington, represents Avista. Sally Brown, Senior Assistant Attorney General, Jeff Roberson, and Nash I. Callaghan, Assistant Attorneys General, Olympia, Washington, represent Staff.[15] Nina Suetake, Ann Paisner, and Lisa Gafken, Assistant

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[13] Public Comments, Exh. BR-3.

[14] *See id.*

[15] In formal proceedings such as this, the Commission's regulatory staff participates like any other party, while the Commissioners make the decision. To assure fairness, the Commissioners, the presiding administrative law judge, and the Commissioners' policy and accounting advisors do not discuss the merits of this proceeding with the regulatory staff, or any other party, without giving notice and opportunity for all parties to participate. *See* RCW 34.05.455.

Attorneys General, Seattle, Washington, represent Public Counsel. Tyler Pepple and Sommer J. Moser, Davison Van Cleve, P.C., Portland, Oregon, represent AWEC. Irion Sanger, Joni Sliger, and Ellie Hardwick, Sanger Law P.C., Portland, Oregon, represent NWEC. Yochanan Zakai and Stacy Lee, Shute, Mihaly & Weinberger LLP, San Francisco, California, represent TEP. Gloria D. Smith, Managing Attorney, Sierra Club Environmental Law Program, Oakland, California; James M. Van Nostrand, Oakland, California; and Jim Dennison, Colorado, represent Sierra Club. Jeff Winmill, James M. Birkelund, and Jennifer Weberski, San Francisco, California, represent SBUA. Vicki M. Baldwin, Parsons Behle & Latimer, Salt Lake City, Utah, represents Walmart.

DISCUSSION AND DECISION

40 The Commission's statutory duty is to establish rates, terms, and conditions for electric and natural gas services that are equitable, fair, just, reasonable, and sufficient. In doing so, the Commission must balance the needs of the public to have safe, reliable, and appropriately priced service with the financial ability of the utility to provide that service. The rates thus must be equitable, in that the distribution of burdens and benefits should reduce, rather than perpetuate, ongoing systemic harms; fair to both customers and the utility; just, in that the rates are based solely on the record in this case following the principles of due process of law; reasonable, in light of the range of potential outcomes presented in the record; and sufficient, to meet the financial needs of the utility to cover its expenses and attract capital on reasonable terms.

41 The Commission is presented with a Settlement that proposes to resolve all disputed issues. The Commission approves settlements "when doing so is lawful, the settlement terms are supported by an appropriate record, and when the result is consistent with the public interest in light of all the information available to the commission."[16] The Commission may approve the Settlement, with or without conditions, or reject it. We determine that, subject to conditions, the Settlement is lawful, its terms are supported by an appropriate record, and its result is consistent with the public interest in light of all the information available. We explain our reasoning, below.

42 In the decisions we make in this Order, we also consider recent federal legislative action that will impact Washington investor-owned utilities. On November 15, 2021, President Biden signed the Infrastructure Investment and Jobs Act (IIJA), which provides a strategic opportunity to upgrade the nation's energy infrastructure for a clean, resilient,

[16] WAC 480-07-750(1).

and secure energy future.[17] The IIJA funds over 350 programs to be overseen through more than a dozen federal departments and agencies.[18] On August 16, 2022, President Biden signed the Inflation Reduction Act (IRA) into law.[19] The IRA is a fiscal policy instrument enacted by the federal government to counterbalance the effects of inflation in specific areas of the economy. It also represents the United States' single largest investment to date to modernize its energy system.[20]

43 The impacts of these laws on rates are not yet known, but it is apparent that both could greatly impact Avista's utility operations during the multi-year rate plan (MYRP) agreed by the Settling Parties. Many aspects of Avista's operations, costs, funding, and financial health may be impacted by these new laws including extension of investment tax credits, creation of new tax credits, accelerated depreciation of clean electricity facilities, and extension of tax credits for investment in certain energy properties, among other aspects.[21] The Biden administration announced additional funding to provide increased

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[17] Infrastructure Investment and Jobs Act of 2021, Pub. L. No. 117-58, 135 Stat. 429 (2021) [hereinafter IIJA].

[18] The White House, *A Guidebook to the Bipartisan Infrastructure Law for State, Local, Tribal, and Territorial Governments, and Other Partners* (May 2022), https://www.whitehouse.gov/wp-content/uploads/2022/05/BUILDING-A-BETTER-AMERICA-V2.pdf.

[19] Inflation Reduction Act of 2022, Pub. L. No. 117-169, 136 Stat. 1818 (2022) [hereinafter IRA].

[20] Jessie Ciulla, Gennelle Wilson, and Rachel Gold, *What Utility Regulators Needs to Know about the Inflation Reduction Act: How to Ensure the Biggest Boon to the Energy System in US History Supports Affordable, Reliable Electric Service*, Rocky Mountain Institute, 2022, https://rmi.org/insight/what-utility-regulators-need-know-about-ira/.

[21] Several sections of the law are included for reference:

Modifies and extends through 2024 the tax credit for producing electricity from renewable resources. IRA at § 13101.

Creates a new clean electricity investment tax credit for investment in qualifying zero-emissions electricity generation facilities or energy storage technology. IRA at § 13702.

Allows a five-year recovery period for the depreciation of clean electricity facilities placed in service after 2024. IRA at § 13703.

Extends through 2024 the tax credit for investment in certain energy properties (*e.g.*, solar, fuel cells, waste energy recovery, combined heat and power, small wind property, microturbine property, and microgrid controllers). Increases credit rate for projects that pay prevailing wages and meet registered apprenticeship requirements. Allows a bonus credit amount for facilities that meet domestic content requirements for steel, iron, and manufactured projects and for facilities located in an energy community. IRA at § Sec. 13102.

Modifies the energy tax credit to allocate 1.8 gigawatts for environmental justice solar and wind capacity credits in low-income communities and Indian lands in 2023 and 2024. Facilities

support for low- and moderate-income families, and complementary tax credits that families and building owners can use under the IRA to install energy-saving equipment and to make building upgrades.[22] More specifically, new resources have been allocated for the federal Low-Income Home Energy Assistance Program (LIHEAP), which has funds that will go to states, territories, and Tribes.[23]

44 Other regulatory commissions have taken action to engage in participative processes to allow interested parties to discuss their thoughts on implementation and to take advantage of the benefits that the laws provide.[24] The impacts of tax credits and other financial provisions will result in changes that impact utility revenue requirement and, ultimately, changes in customers' bills. The IRA could bring significant reductions to energy costs

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receiving allocations must be placed in service within four years after the allocation date. IRA at § 13103.

Creates a new tax credit for qualified commercial clean vehicles. IRA at § 13403.

[22] The White House, *FACT SHEET: White House Announces Additional $385 Million to Lower Home Energy Bills for American Families* (Apr. 21, 2022), https://www.whitehouse.gov/briefing-room/statements-releases/2022/04/21/fact-sheet-white-house-announces-additional-385-million-to-lower-home-energy-bills-for-american-families/.

[23] *Id.*; Department of Energy, *Biden-Harris Administration Announces State and Tribe Allocations for Home Energy Rebate Program* (Nov. 2, 2022), https://www.energy.gov/articles/biden-harris-administration-announces-state-and-tribe-allocations-home-energy-rebate.

[24] *See In re Utility Infrastructure Improvements from the Federal Funding Available Under the Infrastructure Investment and Jobs Act of 2021: Alpena Power Co., et. al.*, Order, Docket U-21227, Mich. Pub. Serv. Comm'n (May 12, 2022), *available at* https://mi-psc.force.com/sfc/servlet.shepherd/version/download/0688y000002tmfNAAQ; *In re Infrastructure Investment and Jobs Act Investigation*, Order Requesting Comment Regarding the Infrastructure Investment and Jobs Act, Docket PU-22-143, N.D. Pub. Serv. Comm'n (Mar. 9, 2022), *available at* https://www.psc.nd.gov/database/documents/22-0143/002-020.pdf; *In re Consideration of the Federal Funding Available Under the Infrastructure Investment and Jobs Act*, Order Allowing Comments Regarding Federal Funding for Utility Service in North Carolina, Docket M-100, Sub 164, N.C. Utils. Comm'n (Feb. 1, 2022), *available at* https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=ee9659cf-dbd6-4ce6-b34f-e8073fcf744e; *In re Investigation into the Implementation of the Federal Infrastructure Investment and Jobs Act*, Docket 22-755-AU-COI, Pub. Utils. Comm'n of Ohio (Aug. 10, 2022), *available at* https://dis.puc.state.oh.us/ViewImage.aspx?CMID=A1001001A22H10B43213C01798; *In re Petition to Open an Administrative Docket to Consider the Federal Infrastructure Investment and Jobs Act of 2021*, Directive Order Establishing Procedural Schedule for Written Comments and Reply Comments, Docket 2022-168-A, Pub. Serv. Comm'n of S.C. (Jun. 9, 2022), *available at* https://dms.psc.sc.gov/Attachments/Matter/3f9d6c58-65f7-41c5-989c-7de70ef7cd2c.

for customers, up to $500 in energy bills savings per year.[25] At least one utility, the Florida Power & Light Company, is planning to phase in nearly $360 million in additional federal tax savings for future planned solar projects starting in 2023 and through 2025. Other, more immediate, savings to customers will be provided in a one-time refund of $25 million in the month of January 2023.[26]

45 All testimony and exhibits were prefiled prior to the enactment of the IRA except for Avista's rebuttal testimony in support of the Settlement. The parties to these consolidated proceedings had no opportunity to consider any of the possible impacts of the IRA and IIJA while negotiating, drafting, or presenting the Settlement to the Commission. Because these changes are significant, we make minor, prudent modifications to the Settlement where necessary to include the impacts of the IRA and IIJA in our retrospective review of provisional plant. In addition, for any other IRA and IIJA benefits unmentioned or unaddressed by this Order, we expect Avista will file with the Commission an accounting petition requesting to defer those benefits.

A. FULL MULTIPARTY SETTLEMENT STIPULATION[27]

46 The Settlement submitted by the Settling Parties proposes to resolve all disputed issues in the proceeding. The Settlement's resolutions of many issues are uncontested or supported by Public Counsel. In its opposition testimony filed with the Commission on July 29, 2022, Public Counsel affirmatively states that many of the Settlement's terms are in the public interest.[28] These issues include:

- Performance Metrics;

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[25] Jessie Ciulla, Gennelle Wilson, and Rachel Gold, *What Utility Regulators Needs to Know about the Inflation Reduction Act: How to Ensure the Biggest Boon to the Energy System in US History Supports Affordable, Reliable Electric Service*, Rocky Mountain Institute, 2022, https://rmi.org/insight/what-utility-regulators-need-know-about-ira/.

[26] *FPL proposes plan to refund customers nearly $400 million in federal corporate tax savings*, News Releases, NEXTera Energy (Sep. 23, 2022), *available at* https://www.investor.nexteraenergy.com/news-and-events/news-releases/2022/09-23-2022-133107538.

[27] The Settlement is included as Appendix A to this Order. Appendix A is incorporated into, and made part of, this Order by this reference. In this Order, we briefly summarize the Settlement's proposed commitments. To the extent any arguable inconsistency exists between our summary and the terms of the Settlement, the terms of the Settlement control.

[28] Dahl, Exh. CJD-1T at 5:17-18.

- Colstrip Cost Recovery: investments in the Dry Ash Disposal System, Colstrip Tracker – Tariff Schedule 99;
- Low-Income Programs;
- Capital Projects Review;
- Residual Tax Customer Credit;
- Cost of Service, Rate Spread, and Rate Design;
- Climate Commitment Act (CCA);
- Small Business Energy Efficiency;
- Natural Gas Transition;
- Distributional Equity Analysis; and,
- Transportation Electrification.

47 However, Public Counsel argues that the Settlement as a whole is not in the public interest, and contests several of the Settlement's terms.[29] Public Counsel asserts that "many components of the Settlement are unreasonable and lack the evidence necessary to support the included terms."[30] Public Counsel recommends that the Commission accept its proposals to resolve certain issues differently than the Settlement.[31] Those contested issues include:

- Overall Revenue Requirement;[32]
- Cost of Capital;
- Projected Energy Imbalance Market (EIM) Benefits;
- Insurance Balancing Account; and,
- Wildfire Issues.

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[29] *Id.* at 5:15-20.

[30] *Id.* at 5:18-19.

[31] *Id.* at 5:21-6:2.

[32] Public Counsel witness Dahl includes "Rate Escalation Study Terms" in Public Counsel's list of Settlement terms it contests. Dahl, Exh. CJD-1T at 8:11. Upon further examination, we understand that Public Counsel's opposition to the rate escalation study is tethered to its opposition to the Settlement's revenue requirement, which Public Counsel argues are derived by use of the rate escalation study. *See* Brief of Staff at 3, n. 3. Public Counsel witness Coppola testifies that Public Counsel agrees with the Settling Parties that the escalation study filed by Avista is not reasonable and should not be used in future rate cases. Coppola, Exh. SC-1CT at 35:3-6. Because this reflects the Settlement's terms regarding the rate escalation study, we consider this an uncontested issue in the remaining discussion of this Order but will consider Public Counsel's arguments as part of its opposition to the Settlement's revenue requirement.

48 It is clear from testimony supporting the Settlement that the Settling Parties entered into an agreement through a complex negotiating process that required them to give and take in different areas to arrive at a combination of resolutions that, taken as a whole, they support as consistent with the public interest.[33] Ultimately, Public Counsel's recommendations would require the Commission to upset the balance struck by the Settling Parties and reject the Settlement as a whole, including the many terms that Public Counsel asserts are in the public interest.[34] We decline to take such action. Instead, in review of the entire record before the Commission, we determine that the Settlement strikes an appropriate balance among the varied and diverse interests presented and find that it meets the standard for the Commission's approval, subject to certain conditions.

49 We address the uncontested and contested issues of the Settlement, in turn, below.

1. UNCONTESTED TERMS

50 Although a number of elements in the Settlement were uncontested, our statutory obligation to regulate in the public interest requires us to evaluate whether the Parties' agreed resolution of issues complies with applicable legal requirements, is supported by an appropriate record, and is consistent with the public interest based on all of the information available to the Commission. Upon review, we find that the Settlement's proposed resolutions of the uncontested issues are lawful, supported by an appropriate record, and consistent with the public interest.

i. Cost of Service: Rate Spread, Rate Design

51 The Settling Parties agree to Avista's rate design proposal in its initial filing but agree not to change the basic charge for Schedules 01/02 (electric) and Schedules 101/102 (natural gas).[35] Public Counsel supports the rate design agreed by the Settling Parties and believes it is in the public interest.[36] The Settling Parties agree to the rate spread illustrated in Table 2 and Table 3, below.[37] Public Counsel neither supports nor opposes the electric

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[33] Settling Parties, Exh. JT-2 at 5, 20, ¶¶ 10, 29-30 [hereinafter Settlement].

[34] *See* Dahl, Exh. CJD-1T at 5:15-6:2.

[35] Settlement at 7, ¶ 12(b). Attachment A to the Settlement provides a summary of the current and revised rates and charges for electric and natural gas services.

[36] Dahl, Exh. CJD-1T at 28:8-29:2; Brief of Public Counsel at 44, ¶ 96.

[37] Settlement at 5-6, ¶ 12(a).

rate spread terms of the Settlement but does support and believe the natural gas rate spread is in the public interest.[38]

52 **Table 2. Electric Rate Spread**

Electric Rate Schedule	**Increase in Base Rates**		**Increase in Billing Rates**	
Rate Year 1	*(in thousands)*		*before Offset*	*with Offsets*
Residential Service, 01/02	$ 26,025	10.3%	10.8%	5.5%
General Service, 11/12	$ 3,264	4.0%	3.7%	3.7%
Large General Service, 21/22	$ 5,247	4.0%	3.7%	3.7%
Extra Large General Service, 25	$ 823	2.0%	2.0%	2.0%
Extra Large Special Contract	$ 435	2.0%	2.0%	2.0%
Pumping Service, 31/32	$ 1,497	10.3%	9.5%	4.9%
Street & Area Lights, 41-48	$ 709	10.3%	10.0%	5.1%
Overall (Rate Year 1)	***$ 38,000***	***6.9%***	***6.8%***	***4.3%***
Rate Year 2	*(in thousands)*			
Residential Service, 01/02	$ 6,318	2.3%	2.5%	
General Service, 11/12	$ 1,919	2.3%	2.1%	
Large General Service, 21/22	$ 3,087	2.3%	2.1%	
Extra Large General Service, 25	$ 420	1.0%	1.0%	
Extra Large Special Contract	$ 222	1.0%	1.0%	
Pumping Service, 31/32	$ 362	2.3%	2.2%	
Street & Area Lights, 41-48	$ 172	2.3%	2.3%	
Overall (Rate Year 2)	***$ 12,500***	***2.1%***	***2.2%***	

[38] Dahl, Exh. CJD-1T at 27:12-28:7; Brief of Public Counsel at 44, ¶ 96.

53 **Table 3. Natural Gas Rate Spread**

Natural Gas Rate Schedule	**Increase in Base Rates**		**Increase in Billing Rates**	
Rate Year 1	*(in thousands)*		*before Offset*	*with Offsets*
General Service, 101/102	$ 5,931	6.6%	4.3%	0.7%
Large General Service, 111/112/116	$ 1,325	6.6%	3.1%	0.5%
Interruptible Service, 131/132	$ 15	6.6%	2.8%	0.5%
Transportation Service, 146	$ 229	6.6%	7.1%	1.2%
Overall (Rate Year 1)	***$ 7,500***	***6.6%***	***4.0%***	***0.7%***
Rate Year 2	*(in thousands)*			
General Service, 101/102	$ 1,185	1.2%	0.8%	
Large General Service, 111/112/116	$ 265	1.2%	0.6%	
Interruptible Service, 131/132	$ 3	1.2%	0.6%	
Transportation Service, 146	$ 47	1.2%	1.4%	
Overall (Rate Year 2)	***$ 1,500***	***1.2%***	***0.8%***	

Commission Determination

54 We find the Settlement's proposed rate spread and rate design are appropriate and in the public interest. The Settling Parties' agreement moves the electric schedules gradually closer towards cost of service parity by allocating a larger share of the electric rate increase to residential customers – a consideration in cost of service that we discussed at length in Avista's 2020 GRC Final Order.[39] While this attributes more of the electric revenue requirement increase to residential customers, the Settling Parties relieve some of this burden by agreeing to return a larger share of the Residual Tax Customer Credit, discussed in detail later, to residential customers, as can be seen by comparing the percentage increase attributed to the residential schedules identified in the column labeled

[39] Miller, Exh. JDM-1T at 7:20-8:3; *see Wash. Utils. & Transp. Comm'n v. Avista Corp., d/b/a Avista Utils.,* Dockets UE-200900, UG-200901, and UE-200894 (*Consolidated*), Final Order 08/05, 109-13, 116, 120-21, ¶¶ 307-20, 328-29, 341-42 (Sep. 27, 2021) [hereinafter 2020 Avista GRC Final Order].

"before Offset" with the column labeled "after Offsets" in Table 2 and Table 3, above.[40] Prior to offsets, which include the Residual Tax Customer Credit, residential customers will see a 10.8 percent increase in billing rates in Rate Year 1, while the average increase in billing rates across all electric customers is 6.8 percent. After offsets including the Residual Tax Customer Credit, the increase in billing rates is reduced to 5.5 percent for residential customers and an average 4.3 percent increase across all electric customers.

55 All parties support the electric rate design, natural gas rate design, and natural gas rate spread. The Settling Parties' agreement removes Avista's initially proposed increase to all electric basic charges and residential natural gas basic charges but maintains increases to the natural gas basic charge for some non-residential schedules.[41] Lastly, all parties support the agreed natural gas rate spread terms that will share an equal percentage of margin increase to the schedules.

56 As a result of the Settlement, in Rate Year 1 a typical residential electric customer using 932 kWhs per month will pay $4.47 more per month, for an average monthly bill of $89.99. In Rate Year 2, a typical residential electric customer using 932 kWhs per month will pay $2.24 more per month, for an average monthly bill of $92.23. In Rate Year 1, a typical residential natural gas customer using 67 therms per month will pay $0.20 more per month, for an average monthly bill of $65.06. In Rate Year 2, a typical residential natural gas customer using 67 therms per month will pay $0.52 more per month, for an average monthly bill of $65.58.[42]

57 We find the Settlement's resolution of the cost of service issues, including the electric and natural gas rate spread and rate design, appropriate and in the public interest. Accordingly, we determine that the cost of service, rate spread, and rate design terms should be approved.

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[40] Joint Testimony, Exh. JT-1T at 17:21-18:2. While stating that it does not oppose or support the Settlement's electric rate spread terms, Public Counsel recognizes that the Settling Parties' agreement provides a larger share of the tax refund amounts to residential customers and "is intended to offset a portion of the increased rates allocated to residential customers." Dahl, Exh. CJD-1T at 27:7-11.

[41] Joint Testimony, Exh. JT-1T at 16:12-17:20, 18:9-19:7, 20:7-21:5.

[42] Response to BR-6.

ii. Residual Tax Customer Credit

58 On March 11, 2021, the Commission entered Order 01 in Dockets UE-200895 and UG-200896, which granted Avista's petition requesting the Commission (1) authorize changing the Company's accounting method from normalization to flow-through for regulatory purposes for federal income tax expense associated with Industry Director Directive No. 5 (IDD #5) and meters, and (2) allow Avista to defer for later ratemaking treatment the tax benefits associated with the change. That change in methodology resulted in amounts due to be returned to customers of approximately $58.1 million, electric, and $28.2 million, natural gas (Tax Customer Credit).[43] In the Final Order of Avista's 2020 GRC, the Commission determined that the Tax Customer Credit amounts should be returned to customers through Tariff Schedules 76 and 176 over a two-year period beginning October 1, 2021, according to the rate spread approved in the 2020 Avista GRC Final Order to offset exactly, in conjunction with the AFUDC Deferral established by the settlement agreement in the 2020 Avista GRC, the rate increase approved by the 2020 Avista GRC Final Order.[44]

59 A portion of the Tax Customer Credit remains unreturned to ratepayers.[45] This unused portion is approximately $27.6 million, electric, and $12.5 million, natural gas (Residual Tax Customer Credit).[46] In the 2020 Avista GRC Final Order, the Commission stated it would reexamine the Residual Tax Customer Credit amount and how to appropriately return it to customers in this current GRC.[47]

60 The Settling Parties agree that Avista will return the Residual Tax Customer Credit of approximately $27.6 million, electric, and $12.5 million, natural gas, to customers through separate Tariff Schedules 78 (electric) and 178 (natural gas) over a two-year amortization period beginning December 21, 2022. Public Counsel supports accelerating the pass-through of tax benefits to customers.[48]

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[43] 2020 Avista GRC Final Order at 44, ¶ 115.

[44] *Id.* at 45, ¶ 120.

[45] Miller, Exh. JDM-1T at 31:14-17.

[46] *See id.* at 31:17-32:2; Settlement at 7, ¶ 13.

[47] 2020 Avista GRC Final Order at 46, ¶ 121.

[48] Coppola, Exh. SC-1CT at 13:13-14:11.

Commission Determination

61 We find the Settlement's proposed treatment of the Residual Tax Customer Credit to be in the public interest. The Residual Tax Customer Credit will be amortized over the two-year rate plan to provide a substantial reduction to customer bills as illustrated in Table 2 and Table 3, above. No party opposes this treatment. As the Commission reasoned in the 2020 Avista GRC Final Order, we likewise find the Settling Parties' proposal to return the Residual Tax Customer Credit through separate Tariff Schedules 78 (electric) and 178 (natural gas) appropriate because it will allow the Commission to best track the return of these benefits to customers. We also find that beginning the process of returning these benefits to customers on the effective date of December 21, 2022, to coincide with the MYRP proposed by the Settlement, will appropriately offset a significant portion of the revenue requirement increases we approve with this Order. Accordingly, we determine that the Settling Parties' agreed treatment of the Residual Tax Customer Credit should be approved.

iii. Colstrip Cost Recovery: Investments in the Dry Ash Disposal System, Colstrip Tracker – Tariff Schedule 99

62 The Settlement contains two terms, in addition to their incorporation into the agreed rate spread and rate design, related to the Colstrip generation plant: the Dry Ash Disposal System, and a new Colstrip Tracker using Tariff Schedule 99.[49] First, the Settling Parties agree that the Settlement's revenue requirement does not include any costs related to the Dry Ash Disposal System.[50]

63 Second, the Settling Parties propose a mechanism with an annual true-up to separately track and potentially recover, subject to a prudence review, certain costs through Tariff Schedule 99 (Colstrip Tracker).[51] The Colstrip Tracker will allocate costs to the rate schedules using a proportional allocation of the first rate year's base revenue spread

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[49] Settlement at 7-9, ¶ 14. Regarding Schedule 99's rate spread and rate design, the Settling Parties agree that the costs removed from base rates will be allocated to the rate schedules through Schedule 99 using a proportional allocation of the Rate Year 1 base revenue spread and that the revenue will be recovered through volumetric charges on a uniform cent per kWh basis. *Id.*

[50] Joint Testimony, Exh. JT-1T at 21:18-20; Joint Testimony, Exh. JT-3T at 4:16-5:1.

[51] Joint Testimony, Exh. JT-1T at 22:2-6; Joint Testimony, Exh. JT-3T at 3:1-5, 4:6-11.

recovered through volumetric charges.[52] The following Colstrip costs, totaling approximately $23.9 million, will be removed from base rates and tracked, reported, and recovered, subject to review, through the Colstrip Tracker:

a. Colstrip Unit 3 and 4 utility plant net of accumulated depreciation (A/D) and ADFIT, excluding all costs associated with the Dry Ash Disposal System project as agreed in the Settlement;

b. Colstrip Regulatory Asset and Liability balances related to decommissioning and remediation (D&R) costs, as first agreed by the settling parties in the 2019 Avista GRC;[53]

c. Production O&M;

d. Depreciation and amortization expense, including the recovery of plant and the Colstrip Regulatory Asset/Liability for D&R costs; and

e. Other costs, including the amortization expense of the Deferred Colstrip Transition Fund, Federal income tax expense, and the tax benefit of debt interest.[54]

64 The Colstrip Tracker will begin December 21, 2022, with the effective date authorized by this Order, and Avista will make an annual filing every October 31 to true up and reset the mechanism effective each January 1.[55] Parties will have 60 days to review Avista's Colstrip Tracker filing and any new Colstrip capital investment for prudency.[56] The Settlement prohibits opposition to either a request for an adjudication or an extension of the 60-day review period.[57]

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[52] Joint Testimony, Exh. JT-3T at 5:4-10, 9:27-32. The proportion of Tariff Schedule 99 allocated to each rate schedule is the same as the proportion of revenue being removed from the base rates of each schedule. *Id.* The Settling Parties agree that this allocation will be used for the life of Tariff Schedule 99. *Id.* Tariff Schedule 99's rate design recovers the revenue through the volumetric charges on a uniform cent per kWh basis. *Id.*

[53] *Wash. Utils. & Transp. Comm'n v. Avista Corp., d/b/a Avista Utils.*, Dockets UE-190334, UG-190335, UE-190222 *(Consolidated)*, Final Order 09, ¶¶ 47-50 (Mar. 25, 2020).

[54] Joint Testimony, Exh. JT-3T at 3:1-12, 4:6-6:5, 8:6-9:19; Joint Testimony, Exh. JT-1T at 22:2-6. The costs removed do not include Dry Ash Disposal costs (which will not be recovered according to the Settlement), or the transmission investment and costs included in the Energy Recovery Mechanism, which would both remain in base rates.

[55] Joint Testimony, Exh. JT-3T at 6:7-10.

[56] *Id.* at 10:13-15.

[57] *Id.*

65 According to the Settlement, the review of Avista's Colstrip Tracker filing will include a prudency review of incurred costs; O&M and other expense items (production O&M and amortization expense) on the test period/restated basis during the two-year rate plan agreed in this case and forecasted thereafter; updated lifetime D&R cost estimates; actual non-O&M costs from the filing year through August 31 and estimated through December 31 (which creates a one-year lag in the recovery of these actual costs), and a true-up to actuals of any forecasted amounts.[58]

66 Finally, the Settlement outlines how it accommodates the requirements of Washington's Clean Energy Transformation Act (CETA) to remove the total costs for Colstrip capital investment and operating expenses, excluding Colstrip transmission investments and ongoing D&R costs, from customer rates after December 31, 2025.[59] The Settling Parties state that "after December 31, 2025, the net Colstrip rate base balances included within Tariff Schedule 99 on a 2025 AMA basis and the appropriate Colstrip expenses would be removed from Tariff Schedule 99."[60] Thus, beginning January 1, 2026, the Colstrip Tracker will include only annually-updated ongoing D&R net rate base balances and Colstrip Regulatory amortization expense (items b. and d. from the above list of costs to be removed from base rates).[61] While the Colstrip D&R cost accounting was included in this GRC, it will not be included in future GRCs because the Settlement removes the costs from base rates.[62] Instead, the accounting for these D&R costs will continue according to the settlement approved in Avista's 2019 GRC, but the recording and tracking will be included in the annual Colstrip Tracker.[63] Public Counsel supports the Settlement's Colstrip terms.

Commission Determination

67 We find the Settlement's agreement related to Colstrip reasonable and appropriate. Public Counsel argues that the Settlement's terms regarding Colstrip are in the public interest

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[58] *Id.* at 6:11-21.

[59] *Id.* at 12:8-13, 13:11-23.

[60] *Id.* at 12:10-13.

[61] *Id.* at 13:1-4.

[62] *Id.* at 13:24-26, 14:18-20.

[63] *Id.* at 14:20-23; *Wash. Utils. & Transp. Comm'n v. Avista Corp., d/b/a Avista Utils.*, Dockets UE-190334, UG-190335, UE-190222 *(Consolidated)*, Final Order 09, ¶ 49 (Mar. 25, 2020). Avista's share of these D&R costs is currently estimated at $28 million, $4.0 million of which has been incurred by Avista through September 30, 2021. Joint Testimony, Exh. JT-3T at 15:1-2.

because "they will assist in the Company's CETA compliance obligations" and will "assist the Commission and other [interested persons to] identify which Colstrip-related costs should and should not be included in customer rates as the clean energy transition proceeds."[64] We agree.

68 CETA requires each Washington electric utility to "eliminate coal-fired resources from its allocation of electricity" exclusive of "costs associated with decommissioning and remediation of" coal-fired facilities.[65] The Settling Parties' agreement will aid the Commission and all interested parties in identifying and tracking costs appropriately recovered from Washington ratepayers. In addition, the Settlement establishes expectations and procedures that will ensure a transparent and fair review of the amounts to be recovered through the Colstrip Tracker. Accordingly, we determine that the Settling Parties' agreements regarding Colstrip should be approved.

iv. Escalation Study

69 In its initial filing, Avista presented an escalation study with a growth rate methodology to use "for the purposes of escalating certain regulatory balances in the determination of future revenue requirements during multi-year rate plans, and beyond first or second year pro forma study levels."[66] The escalation study is described in Avista's initial filing by its witness Andrews and utilizes Dr. Forsyth's Escalator Growth Rates.[67] The Settlement provides that "[t]he Settling Parties do not agree that the escalation study filed by Avista is reasonable or should be used in future rate cases."[68] Public Counsel agrees with the Settling Parties.[69]

Commission Determination

70 We find the Settlement's agreement related to Avista's escalation study reasonable. Accordingly, we determine that the Settling Parties' agreement regarding Avista's escalation study should be approved.

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[64] Dahl, Exh. CJD-1T at 25:17-26:5.

[65] RCW 19.405.030(1)(a).

[66] Andrews, Exh. EMA-1T at 76:5-8.

[67] *Id.* at 75:1-79:5; Forsyth, Exh. GDF-1T at 5:5-8:9.

[68] Settlement at 9, ¶ 17.

[69] Coppola, Exh. SC-1CT at 35:4-6; *see supra* n. 32.

v. Capital Planning

71 As a term of the Settlement, Avista agrees to make a compliance filing in these Dockets by the end of the MRYP, demonstrating how it considers equity in its capital planning process.[70] Specifically, Avista will include in its compliance filing a process or procedure for how its Board of Directors and senior management will incorporate equity into its business planning, including how Avista will plan for equitable outcomes when evaluating business cases.[71] Avista will also include templates to be used in its business cases.[72] These templates will require sponsors to demonstrate how they planned for equitable outcomes in each business case.[73] In addition, Avista will work with its Equity Advisory Group (EAG) and interested persons to develop new equity-related measures, costs, and benefits to be included in its benefit and cost analysis, including qualitative and non-qualitative measures related to societal impacts, non-energy benefits and burdens, indoor and outdoor air quality, the Social Cost of Carbon, and Named Communities.[74]

72 Avista will also include in its post-MYRP compliance filing a plan for measuring and tracking the impacts from each business case after the project's completion, "with a specific eye towards identifying equitable outcomes, and how the Company will engage in adaptive management to correct course during Business Cases when it is necessary to avoid inequitable outcomes."[75] The plan for measuring and tracking impacts must include assessments of impacts from business cases and, wherever possible, feedback from interested persons and communities impacted by the business case.[76] The plan for measuring and tracking impacts should also demonstrate the importance of the issues to Named Communities along with "a holistic picture of the current conditions faced in those communities."[77]

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[70] *See* Settlement at 10, ¶ 18.

[71] Settlement at 10, ¶ 18.

[72] *Id.*

[73] *Id.*

[74] *Id.* "Named Communities" refers to highly impacted communities and vulnerable populations.

[75] Settlement at 10, ¶ 18.

[76] *Id.*

[77] *Id.*

Commission Determination

73 We find the Settlement's terms related to Avista's capital planning and the inclusion of equity considerations in that planning appropriate. As we stated in our final order in Cascade Natural Gas Company's most recent general rate case (Cascade Final Order), "Recognizing that no action is equity-neutral, regulated companies should inquire whether each proposed modification to their rates, practices, or operations corrects or perpetuates inequities."[78] Accordingly, the Settlement terms requiring Avista to make a compliance filing demonstrating changes to its capital planning to include equity considerations will provide an opportunity for Avista to demonstrate its progress towards addressing the principles identified in the Cascade Final Order, and in particular a comprehensive understanding of the ways systemic and historical inequities are present and continue to operate. We therefore approve the terms.

74 The processes or procedures Avista considers for all capital planning should consider and implement energy justice and its core tenets. The core tenets of energy justice are:

- Distributional justice, which refers to the distribution of benefits and burdens across populations. This objective aims to ensure that marginalized and vulnerable populations do not receive an inordinate share of the burdens or are denied access to benefits.

- Procedural justice, which focuses on inclusive decision-making processes and seeks to ensure that proceedings are fair, equitable, and inclusive for participants, recognizing that marginalized and vulnerable populations have been excluded from decision-making processes historically.

- Recognition justice, which requires an understanding of historic and ongoing inequalities and prescribes efforts that seek to reconcile these inequalities.

- Restorative justice, which is using regulatory government organizations or other interventions to disrupt and address distributional, recognitional, or procedural injustices, and to correct them through laws, rules, policies, orders, and practices.[79]

[78] *Wash. Utils. & Transp. Comm'n v. Cascade Natural Gas Corp.,* Docket UG-210755, Order 09, 19, ¶ 58 (Aug. 23, 2022) (citing RCW 80.28.425(1) [hereinafter Cascade Final Order].

[79] *Id.* at 18, ¶ 56.

vi. Distributional Equity Analysis

75 To better incorporate equity into its capital planning processes, the Settling Parties agree to develop methods and standards for distributional equity analysis (consistent with guidance provided in the New York University Institute for Policy Integrity, 2022), and to file those methods and standards for Commission approval within 24 months of this Order.[80] The Settlement provides that Staff will direct this process and select a facilitator for Avista to hire.[81] If the Settling Parties disagree regarding these methods and standards, the Settling Parties agree that each will file separate proposals for Commission consideration and approval.[82] Public Counsel agrees with the Settling Parties that the agreement to develop methods and standards for distributional equity analysis is in the public interest.[83]

Commission Determination

76 There is a clear need for a process to develop methods and standards for distributional equity analysis. Additionally, we agree that of all the Settling Parties, Staff possesses an expertise and impartiality that makes its selection as the directing party in the proposed process appropriate. We disagree, however, that the process proposed by the Settling Parties is the most appropriate option and find that it is appropriate for the Commission to establish a Commission-led collaborative proceeding to address these issues.

77 The issue of equity, broadly, and the need to consider distributional equity in planning processes affects all utility companies regulated by the Commission. The development of a plan for distributional equity requires input, collaboration, and buy-in from persons and parties not included or represented in Avista's general rate case. Lastly, the importance of this work demands a shared burden of responsibilities and a process that shares and allocates power inclusively. For the above reasons, the Commission finds it appropriate to require the modification of the Settling Parties' agreement for distributional equity analysis and determines that it will facilitate a broader Commission-led collaborative involving all regulated utilities and interested persons. In their post-hearing briefs, both

[80] Settlement at 11, ¶ 19.

[81] *Id.*; Joint Testimony, Exh. JT-1T at 27:19-20.

[82] Settlement at 11, ¶ 19.

[83] Dahl, Exh. CJD-1T at 24:12-13.

Staff and Avista conveyed comfort with and support for a Commission-led collaborative or generic proceeding.[84]

78 Accordingly, we determine that approving the Settlement should be conditioned on certain modifications to the process outlined by the Settling Parties' agreement to develop methods and standards for distributional equity analysis.

> **Condition.** We condition our approval of the Settlement on the modification of the portion regarding distributional equity analysis. Instead of the process the Settling Parties have agreed (that Staff will direct this process and select a facilitator for Avista to hire), we determine that the Commission should establish a broad, Commission-led collaborative process to establish methods and standards for distributional equity analysis and that Avista should be required to participate, as is the expectation for all Washington investor-owned utilities. Subject to this condition, we determine that the Settling Parties' agreement regarding distributional equity analysis is in the public interest and should be approved.

vii. Capital Projects Review

79 The Settling Parties agree to the reporting process for reviewing capital projects outlined in Avista witness Andrews's testimony, with certain changes.[85] Avista's provisional capital reporting will include assurance that the "provisional capital included prior to the rate effective period (for 2022 capital) and during [Rate Year 1] (2023 capital) and [Rate Year 2] (2024 capital) is in service for customers during the rate effective periods, or will be subject to refund."[86] The Settling Parties' proposed changes extend the review period from three to four months to allow parties to review and respond to Avista's annual capital report filing. Within 30 days of completing the capital projects review, Avista would be required to file with the Commission an accounting petition to provide refunds, and create a separate tariff through which rate refunds to customers will be returned and spread to schedules based on an equal share of base rate revenues, exclusive of tax credit refunds.[87] For the purposes of the Capital Projects Review only (*i.e.*, for the comparison of provisional capital additions included in Rate Year 1 and Rate Year 2), the Settling Parties further agree that Rate Year 1 and Rate Year 2 capital additions and rate base are

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[84] Brief of Staff at ¶ 23; Brief of Avista at ¶ 38, n. 26.

[85] Settlement at 11-12, ¶ 20; Andrews, Exh. EMA-1T at 45:10-48:2.

[86] Andrews, Exh. EMA-1T at 46:1-4.

[87] Settlement at 11-12, ¶ 20.

adopted as initially filed by Avista except with the exclusion of the Dry Ash Disposal System.[88] Table 4, below, illustrates the updates from the Settlement to net plant balances for Rate Year 1 and Rate Year 2.[89] Public Counsel supports the terms regarding Capital Project Review and believes they are in the public interest.[90]

80 **Table 4. Two-Year Rate Plan Net Plant After ADFIT Balances *(in thousands)*[91]**

	Electric Rate Base	Natural Gas Rate Base
Test Period	$ 1,797,278	$ 438,149
Adjustments	*$ 189,878*	*$ 71,999*
Rate Year 1	$ 1,987,156	$ 510,148
Dry Ash Disposal System	$ (3,123)	---
Settlement Balances[92]	$ **1,984,033**	$ **510,148**
Adjustments	*$ 80,506*	*$ 22,198*
Rate Year 2	$ 2,067,662	$ 532,346
Dry Ash Disposal System	$ (2,112)	---
Settlement Balances[93]	$ **2,065,550**	$ **532,346**

Commission Determination

81 We find the Settlement's agreement related to Capital Projects Review reasonable for the resolution of the issues presented in this GRC.

82 We expressly limit our approval, however, to this GRC and emphasize that our decision should not be considered precedential for future proceedings. Some impacts from the

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[88] Joint Testimony, Exh. JT-1T at 28:13-16.

[89] *Compare with* Andrews, Exh. EMA-1T at 31:17-22.

[90] Brief of Public Counsel at 43-44, ¶ 96.

[91] Net Plant for each calendar year represents "all actual additions, retirements, offset by Accumulated Depreciation (A/D) and [ADFIT]." Andrews, Exh. EMA-1T at 46:10-15.

[92] Net Plant balance for Rate Year 1 effective 12/31/2022.

[93] Net Plant balance for Rate Year 2 effective 12/31/2023.

IRA and IIJA will affect capital investment and could provide immediate customer savings, as we highlighted previously.[94]

83 The Commission intends to initiate a collaborative or generic proceeding to include all affected, or potentially affected, utilities as well as interested persons to discuss, address, and plan for benefits and opportunities resulting from the IRA and IIJA that may impact the companies' costs. This is not a condition of our approval of the Settlement, but an indication of action tangential to this GRC that the Commission will take to appropriately address impacts to all regulated utilities, not only Avista.

84 As it concerns the Settling Parties' agreement for capital projects review during the MYRP, we take a particular interest in how the IRA and IIJA may impact the retrospective review of provisional plant (capital projects). The precise impacts and extent of those impacts is currently unknown. However, it is apparent that there are opportunities for benefits to Avista for planning of capital projects, and more urgently in capturing any changes that will result in immediate customer savings. We find it imperative that Avista pursue what opportunities the IRA and IIJA might offer during the time the MYRP is effective. For that purpose, we find it appropriate for Avista to record and share its efforts for identifying opportunities for rate mitigation, its efforts in seeking federal benefits, as well as those benefits it actually receives under the federal programs.

85 Accordingly, we determine that approval of the Settlement should be conditioned on certain modifications to the Settling Parties' agreement for the review of capital projects during the MYRP.

> **Condition.** We condition our approval of the Settlement on the modification of the capital projects review, requiring that Avista must demonstrate all offsetting benefits received or for which it has applied for through the IRA and IIJA for all retrospective review of provisional plant (capital projects). Further, we require Avista's reporting to include all funding for which it has applied and the reasons justifying any decision not to pursue IRA and IIJA funding options for which it may be eligible. Subject to this condition, we determine that the Settling Parties' agreement regarding capital projects review is in the public interest and should be approved.

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[94] *Supra* paragraphs 42-45.

viii. Natural Gas Transition Issues

86 The Settling Parties agree to several terms related to natural gas transition, including terms regarding line extension allowances, non-pipe alternatives, customer reporting requirements, and the development of a natural gas decarbonization plan.[95] In particular, the Settlement establishes a timeline to phase out the Natural Gas Line Extension Allowance by January 1, 2025.[96] It also requires Avista to consider "non-pipe alternatives" in its gas distribution planning process and to discuss this consideration in future natural gas integrated resource plans.[97] Avista must also provide quarterly reporting on the number of new gas customers relative to new electric customers.[98] Last, in its 2023 Natural Gas IRP, Avista must include a plan for complying with the CCA.[99] Public Counsel supports the Settlement's natural gas transition terms and believes that they are in the public interest.[100]

Commission Determination

87 We find the Settling Parties' agreements regarding natural gas transition issues appropriate. The CCA implements a statewide cap-and-invest program that will make Washington carbon-neutral by 2050, cut Washington's carbon emissions by 95 percent compared to 1990 emission levels by 2050, and offset the remaining 5 percent using carbon reduction, removal, or avoidance projects.[101] The CCA sets a limit on overall carbon emissions in the state and requires emitters to obtain "emission allowances" equal to their covered greenhouse gas (GHG) emissions.[102] Avista, as an electric and natural gas utility, must comply with the CCA.

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[95] Settlement at 12-13, ¶ 21.

[96] *Id.* Line extension allocation will be based on the net present value methodology using a two-year timeframe for 2023 and one-year timeframe for 2024. Joint Testimony, Exh. JT-1T at 29:6-19.

[97] Settlement at 12-13, ¶ 21(b). The Settlement provides that at minimum, "non-pipe alternatives" include demand-side management measures, envelope efficiency measures, electrification, and gas demand response. *Id.*

[98] Settlement at 13, ¶ 21(c).

[99] *Id.* ¶ 21(d); Joint Testimony, Exh. JT-1T at 29:6-31:3.

[100] Brief of Public Counsel at 43-44, ¶ 96; Dahl, Exh. CJD-1T at 30:1-7.

[101] *See* RCW 70A.65.005(2)-(7).

[102] RCW 70A.45.020; RCW 70A.65.060; RCW 70A.65.070; RCW 70A.65.080; RCW 70A.65.200.

88 The Settling Parties' agreement will promote prudent planning and, in many ways, will aid Avista's compliance with the requirements of the CCA. Accordingly, we determine that the Settlement's natural gas transition terms agreed by the Settling Parties are reasonable, in the public interest, and should be approved.

ix. Transportation Electrification

89 Consistent with RCW 80.28.360, the Settling Parties agree that Avista's request for an incentive rate of return (ROR) on transportation electrification investments is embedded within the revenue requirement for the duration of the MYRP subject to the establishment of two performance metrics.[103] The transportation electrification performance metrics are: (a) percent of utility-owned and supported electric vehicle supply equipment (EVSE) by use case located within and/or providing direct benefits and services to Named Communities; and, (b) percent of load shifted to off-peak periods attributable to transportation electrification tariff offerings by use case, including electric vehicle load subject to managed charging.[104] The Settling Parties also agree to minimum payment method requirements for publicly-accessible charging stations and agree that any party can oppose or propose alternative approaches to incentive return on equity (ROE) for transportation electrification in future cases.[105] The Settlement does not establish any performance incentive mechanisms. Public Counsel supports the Settlement's transportation electrification terms and believes that they are in the public interest.[106]

Commission Determination

90 We find the Settlement's transportation electrification terms, including authorizing an incentive rate of return (ROR) on transportation electrification investments, to be reasonable. It is appropriate that the terms of the Settlement do not prevent parties from opposing or proposing new and alternative solutions related to incentivizing transportation electrification in the future.

91 In addition, the incentive ROR included in revenue requirement for transportation electrification investments is subject to the establishment of the related performance

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[103] Settlement at 13-14, ¶ 22; *see* RCW 80.28.360.

[104] Settlement at 14, ¶ 22.

[105] Settlement at 13-14, ¶ 22.

[106] Brief of Public Counsel at 43-44, ¶ 96; Dahl, Exh. CJD-1T at 30:15–31:10.

metrics.[107] As we describe in further detail below regarding the Settlement's agreed performance metrics, we accept the establishment of the performance metrics proposed by the Settling Parties related to Avista's transportation electrification investments. We also find it important to note that the Settling Parties' agreement incorporates the incentive ROR for transportation electrification into the results-only revenue requirement and is not *in addition to* the agreed results-only revenue requirement agreement.[108] We find it appropriate that, in the context of a results-only revenue requirement agreement, the agreed amount of the incentive ROR for transportation electrification is not in addition to the agreed revenue requirement. Accordingly, we determine that the Settlement's transportation electrification terms agreed by the Settling Parties are reasonable, in the public interest, and should be approved.

x. Performance Based Ratemaking

92 The Settling Parties agree to 92 performance metrics included in Attachment B, which includes two metrics related to transportation electrification plus the commitment to develop additional reliability metrics.[109] The Settling Parties' agreement does not include the proposal by Avista in its initial filing regarding financial performance incentive mechanisms (PIMs).[110] The 92 metrics identified in Attachment B to the Settlement regard numerous topics, which are categorized by Table 5, below.

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[107] Settlement at 13, ¶ 22.

[108] *See* Joint Testimony, Exh. JT-1T at 31:17-19.

[109] Settlement at 14-15, ¶ 23.

[110] *Id.*; Joint Testimony, Exh. JT-1T at 32:1-6, 32:11-14, 34:6-7; Settlement Stipulation Attachment B.

93 **Table 5. Settlement Performance Metrics by Topic and Sub-Topic**

Topic	Sub-Topic	# of Metrics
Affordable Service		15
Capital Formation		2
Equitable Service		17
Satisfy Customer Needs	Electric Reliability	15
	Wildfire	17
	Customer Experience	6
Advance Societal Outcomes	Pollution, GHG Emissions Reduction	7
	Electric Grid Benefits	10
Natural Gas System Benefits		3
Total		92

94 The metrics listed in Attachment B will be used for tracking purposes.[111] As part of the Settlement, Avista agrees to report and publish, on either a quarterly or annual basis starting 45 days after the first quarter of 2023, the results of each metric on its website and to maintain and make public the historical results.[112] Each metric will be reported in real terms while "using an appropriate measure of inflation."[113] Additionally, the Settling Parties propose to develop by March 31, 2023, reliability metrics to be tracked and reported by the beginning of Rate Year 2.[114]

95 Public Counsel supports the Settlement's terms regarding performance-based ratemaking and believes that they are in the public interest.[115]

[111] Settlement at 14-15, ¶ 23.

[112] Joint Testimony, Exh. JT-1T at 31:17-19, 32:14-34:4.

[113] *Id.* at 34:5-6.

[114] *Id.* at 34:6-9; *see supra* Section ix., above, for the two metrics established for transportation electrification.

[115] Public Counsel Brief at 43-44, ¶ 96; Crane, Exh. ACC-1T at 10:11-18:16.

Commission Determination

96 We find the Settlement's agreed performance metrics appropriate but find that Avista should be required to report all of the Settlement's metrics to the Commission. The Commission finds that the performance metrics are measures consistent with RCW 80.28.425, that these metrics will be informed by the Commission's performance-based regulation proceeding in Docket U-210590, and that establishing metrics and measures for performance-based ratemaking is an iterative process. In Docket U-210590, a Performance Metric or Performance Measure is defined as measurable and quantifiable data used to track specific actions, outcomes, or results. It is often expressed in terms of standard power system measures or consumer impact measures. Additionally, we agree with Public Counsel who, in brief, explains that:

> Approval of these performance metrics and associated Company activities included in the Settlement meets the requirements of the Multiyear Rate Plan statute. The statute does not define "measure," but the dictionary definitions of the word include "an action to achieve something" and "a step planned or taken as a means to an end." The statute is not prescriptive as to the types of actions that constitute a "measure." The list of performance metrics, coupled to the requirement that Avista track each of the ninety-two separate metrics, are an action intended to collect and track utility performance in nine different performance categories through the multiyear rate plan.[116]

97 The terms of the Settlement provide that these performance metrics are for tracking purposes and do not state whether these metrics should be used to evaluate the MYRP.[117] The Settlement lacks detailed information identifying or directing how the Commission might use these metrics to evaluate the MYRP or the agreed calculations for all metrics under RCW 80.28.425(7). The Commission therefore finds it necessary to meet its statutory obligation under RCW 80.28.425(7) by adopting a limited number of performance measures, described later in Section C of this Order, that it will use to

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[116] Brief of Public Counsel at 45, ¶ 98 (citing MacMillian Education Limited: MacMillian Dictionary.com, *MacMillian Dictionary* https://www.macmillandictionary.com/us/dictionary/american/measure_1 (last accessed Oct. 20, 2022); Merriam-Webster, Merriam-Webster.com Dictionary, https://www.merriam-webster.com/dictionary/measure (last accessed Oct. 20, 2022)).

[117] Settlement at 14-15, ¶ 23.

evaluate Avista's operations during the MYRP. The Settling Parties do not oppose adding requirements for Avista to report the performance metrics to the Commission, and we determine that such reporting will be useful as the Commission and parties refine their use of performance metrics over time. Further, the Settlement's agreed performance metrics are not binding on the Commission, and we expressly determine that our approval of the Settlement should not impute precedential value to their continuation should the Commission determine that other or additional metrics or measures are more appropriate in the future for the same or other purposes.

98 Last, the Commission declines to provide guidance on PIMs in this Order. These issues and their relation to the statutory requirements of RCW 80.28.425(7) will be explored in Phase 3 of the Commission's performance-based ratemaking proceeding in Docket U-210590. Staff and all other parties are invited to provide comments and proposals in that proceeding.

99 Accordingly, we determine that approval of the Settlement should be conditioned on certain modifications to the Settlement's agreed performance metrics.

> **Condition.** We condition our approval of the Settlement on the inclusion of requirements for reporting the performance metrics to the Commission. Avista must report each of the performance metrics in a filing with the Commission within 45 days of the conclusion of the relevant reporting period. We also require the Settling Parties to review reported performance metrics and provide feedback and recommendations for the Commission to consider within 45 days from the filing date of the report. Subject to these conditions, we determine that the Settling Parties' proposed metrics and proposal for performance-based ratemaking is reasonable, consistent with applicable law, in the public interest, and should be approved.

xi. Low-Income

100 The Settling Parties agree to several terms affecting Avista's low-income programs.[118] First, the Settling Parties agree to recommend that the Commission not approve certain proposals in Avista's initial filing, and that the proposals will be further discussed and developed in consultation with the Company's Energy Assistance Advisory Group (EAAG), with Avista filing the resulting proposals with the Commission on July 1,

[118] Settlement at 15-17, ¶ 24.

2023.[119] Specifically, Avista agrees to consult and seek consensus with its EAAG concerning program design and implementation issues, including the joint administration of enrollment by Avista or the Community Action Agencies (CAAs); the use of self-attestations of income along with random audits instead of verifying all participating customers' income, and, the management of overlap between the federal Low-Income Home Energy Assistance Program (LIHEAP) and Avista's Bill Discount program.[120]

101 Second, the Settling Parties agree that Avista's proposal for the administration and program support budget apportioned to the CAAs is the minimum amount that will be made available for the 2023-2024 and 2024-2025 Low-Income Rate Assistance Program (LIRAP) years.[121] Avista agrees to collaborate with its EAAG to determine the appropriate method, amounts, and administrative structure for future LIRAP years.[122] Any funding increases proposed by its EAAG will be included in the July 1, 2023, filing , and Avista's 2024 annual filing in September.[123]

102 Third, the Settling Parties agree that Avista may only recover the following expenses through Schedules 92 and 192: Direct Services to customers, CAA Administration and Program Delivery, CAA Conservation Education Staff and Labor, Avista Conservation Education, and LIRAP Outreach.[124]

103 Fourth, Avista agrees that it will work with its EAAG to identify a new renewable energy project or projects for the direct benefit of low-income customers.[125] In addition, the Settling Parties agree that Avista may identify a new renewable energy project or projects

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[119] Settlement at 15, ¶ 24(a).

[120] Settlement at 15, ¶ 24(a)(i).

[121] Settlement at 15, ¶ 24(b); *see* Bonfield, Exh. SJB-1T.

[122] Settlement at 15-16, ¶ 24(b).

[123] Settlement at 16, ¶ 24(b).

[124] Settlement at 16, ¶ 24(c). The Settling Parties agree that Avista cannot recover other expenses through Schedules 92 and 192, including Avista's associated labor; EAAG expenses, including facilitator and participant payments; labor or other costs associated with the reporting of metrics concerning low-income customers and energy burden pursuant to CETA or performance-based regulation metrics, and labor and other costs associated with reporting to the Washington Department of Commerce. *Id.*; *but cf.* Settlement at 16-17, ¶ 24(d).

[125] Settlement at 16, ¶ 24(d). The Settling Parties agree that funding may come from Schedules 92 or 192 but may only fund projects benefitting eligible low-income customers. Settlement at 16-17, ¶ 24(d). *See* Cebulko, Exh. BTC-1T at 9:12-18.

for the direct benefit of customers residing in Named Communities.[126] Avista agrees to file with the Commission a work plan describing its plan to facilitate the development of a new renewable energy project or projects, including the budget, funding sources, timeline, and community partners, by December 1, 2023.[127]

104 Last, Avista agrees to low-income conservation and weatherization terms, including increasing low-income conservation and weatherization funding through Schedules 91 and 191 up to $4.0 million in 2023 and $4.25 million in 2024; developing a pilot program in consultation with its EEAG to overcome the inability to weatherize homes because of deferred maintenance or large repairs, and surveying actual installed measure costs and, based on the results of the survey, adjusting the rebate amounts if warranted and fully funding low-income conservation measures.[128]

105 Public Counsel supports the Settlement's low-income terms and believes that they are in the public interest.[129]

Commission Determination

106 We find that the Settlement's low-income terms are positive steps designed to remove barriers to access and seek greater engagement with Highly-Impacted Communities and Vulnerable Populations. As the Commission determined in the Cascade Final Order, advancing energy justice is integral to achieving equity in Washington's energy regulation. Among other things, energy justice focuses on ensuring that individuals have access to energy that is affordable, safe, sustainable, and affords them the ability to sustain a decent lifestyle. Here, the low-income provisions of the Settlement propose that

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[126] Settlement at 16, ¶ 24(d). The Settling Parties agree that funding may come from Avista's Named Communities Investment Fund. *Id.*

[127] Settlement at 17, ¶ 24(d). The Settling Parties agree that this requirement is independent of and incremental to condition 10 of Avista's CEIP. *Id.* Condition 10 of Avista's CEIP states:

> By December 1, 2022, in collaboration with its EAG and EAAG and per WAC 480-100-640(5)(a) and (c), Avista agrees to identify at least one specific action that will serve a designated subset of Named Communities, to be funded by the Named Communities Investment Fund, and to identify and track all CBIs relevant to this specific action. The location identified for the specific action will be at the granularity of the designated Named Communities subset.

Cebulko, Exh. BTC-1T at 9, n. 13.

[128] Settlement at 17, ¶ 24(e).

[129] Brief of Public Counsel at 43-44, ¶ 96; Dahl, Exh. CJD-1T at 18:10-23:4.

the Company work with its EAAG to make significant changes to Avista's low-income programs that will increase access to, and enrollment in, those programs. Specifically, the Settlement increases the EAAG's involvement in program design and implementation, demonstrates a deeper understanding of the flexibility necessary for certain budgeting structures, and demonstrates the Settling Parties' intent to proactively incorporate considerations for including low-income and Named Communities in new renewable energy projects. Consistent with our decision on the retrospective review of provisional plant, we find it imperative that Avista seek out IRA and IIJA funding opportunities related to supporting and promoting low-income programs, projects, and interests.

107 Public Counsel, while not a party to the Settlement, highlights several barriers that the Settlement will, or at least will attempt to, remove. Regarding barriers to enrolling customers in need of assistance, Public Counsel witness Dahl explains that

> removing barriers to customers qualifying for and receiving energy assistance funds has been a major point of conversation among stakeholders. Determining how to use and assess the accuracy of self-attested income to demonstrate qualifications is an important step toward reducing the administrative barriers customers with high energy burdens face. These assessments should strike a balance between gathering information necessary to determine compliance rates and creating new, unintended barriers to program participation.[130]

108 We agree and find that the Settlement's terms requiring Avista and its EAAG to engage in consensus-seeking consultations on the new program design, including self-attestation of income with random audits, should remove barriers and result in increased enrollment. We also find that the terms requiring Avista to file the resulting design recommendations will create a fair procedure, an appropriate timeline, and incentives for productive engagement.

[130] Dahl, Exh. CJD-1T at 19:19-20:4. The Commission is working to eliminate from its documents the non-inclusive and historically problematic term "stakeholders" and instead use terms like "interested persons," "participants," "persons," or "non-company parties," depending on the situation. We urge others to do the same.

109 Regarding low-income weatherization, witness Dahl explains that

> In many cases, weatherization measures are unable to be installed or would be ineffective without addressing maintenance issues in customers' homes. This is an issue agencies who coordinate funding and implementation of low-income weatherization projects raise regularly. Piloting a program to remove this important obstacle to completing projects is in the public interest.[131]

We agree. While some programs do not require a pilot, we find that the Settling Parties' agreement to begin a pilot program for these purposes is appropriate because it will likely expedite its implementation.

110 TEP, a party to the Settlement, filed separate testimony in support of the Settlement, addressing its support of many of Avista's low-income proposals. In particular, TEP witness Cebulko discussed Avista's proposed five-tier bill discount program as it is paired with programs that address arrearages. Witness Cebulko explains that

> TEP strongly supports the use of a five-tier bill discount program, where customers with the lowest incomes receive the largest bill discount in the first tier, customers with slightly higher incomes receive a slightly lower bill discounts in the second tier, and so on. Similarly, TEP strongly supports the Past Due Payoff (PDP) program immediately forgiving past due balances for the customers with the lowest incomes, and the Arrearage Management Plan (AMP), which forgives past due balances for other low-income customers who sustain regular payments. Taken together the five-tier bill discount program and PDP/AMP show promise as a cornerstone strategy to reduce household energy insecurity and retain access to essential utility service in Washington.[132]

111 We agree that reducing household energy insecurity and retaining access to essential utility services in Washington are important equity considerations that are consistent with the public interest. It appears, however, from the absence of terms in the Settlement

[131] Dahl, Exh. CJD-1T at 23:16-20.

[132] Cebulko, Exh. BTC-1T at 6:19-7:7.

outlining the PDP, AMP, or five-tier bill discount program, that more discussion is needed regarding these programs and their designs. We support the Settlement's terms under which Avista will further engage with the EAAG to collaboratively develop program designs that promote equity and access to those in need of its energy assistance programs.

112 We find the low-income terms in the Settlement remarkable for the progress they make towards reducing barriers and promoting equity and access.[133] However, we find that some elements are missing, albeit due to circumstances and timing beyond the parties' control. Funding available through the IRA and IIJA might be attainable for supporting and promoting many programs, including low-income programs, projects, and interests. Critically, we find that considerations of what funding may be available cannot wait and should be undertaken immediately in appropriate forums. Here, we find that Avista's consultations with its EAAG is an appropriate forum. We observe, unfortunately, that the Settlement lacks any indication of how the IRA and IIJA might be beneficial for low-income considerations. Accordingly, we determine that approval of the Settlement should be conditioned on certain modifications to the Settlement's low-income terms.

> **Condition.** We condition our approval of the Settlement on the inclusion in Avista's consultations and consensus-seeking with its EAAG, as well as its July 1, 2023, and September filings with the Commission, of its considerations for how funds through the IRA and IIJA might be used to support and promote low-income programs, projects, and interests. Further, Avista will report in future low-income annual filings during the MYRP its actions to seek funding through the IRA and IIJA to support and promote low-income programs, projects, and interests. Subject to this condition, we determine that the Settling Parties' agreed low-income terms are reasonable, consistent with applicable law, in the public interest, and should be approved.

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[133] Neither Avista, nor any other regulated company, should consider the equity considerations in this Order comprehensive, as we will continue to expand upon this discussion of equity in future proceedings. We decline to provide specific programmatic guidance, as our discussion of equity and the low-income terms of this Settlement is only the beginning of a broader understanding and expectation of equity considerations in Washington's energy regulation going forward. For now and the near future, we reiterate our expectation set out in the Cascade Final Order that Avista, and all other regulated investor-owned utility companies, must integrate considerations of equity into every proposal through an energy justice lens.

xii. Climate Commitment Act

113 The Settlement provides that, within 60 days of the adoption of the final Department of Ecology rules implementing the CCA (Chapter 173-446 WAC), Avista will begin consulting with its applicable advisory groups to develop plans for compliance with the CCA, including reporting requirements, proper treatment of revenues from the consignment of allowances, and the investment of any proceeds from the sale of allowances during the MYRP.[134] Public Counsel supports the Settlement's CCA terms and believes that they are in the public interest.[135]

Commission Determination

114 We find the Settlement's terms related to the CCA appropriate. At hearing, Commissioner Doumit inquired whether the parties would find it helpful and if they would support Commission efforts to schedule consultative and collaborative meetings to discuss utility compliance with the CCA, generally.[136] Both Avista and NWEC stated that work sessions around compliance with the CCA would be helpful.[137]

115 We agree with the Settling Parties that Avista should begin consulting with its advisory groups concerning the requirements of the CCA, CCA allowances, and the accounting treatment of proceeds under the CCA. Additionally, the Commission intends to schedule meetings, workshops, or collaborative work sessions as described by Commissioner Doumit during these consolidated proceedings' hearing to discuss utility compliance, generally, with the CCA. Accordingly, we determine that the Settlement's CCA terms are in the public interest and should be approved.

xiii. Small Business Energy Efficiency

116 The Settling Parties agree that Avista will begin, by June 30, 2023, discussions with its Energy Efficiency Advisory Group (EEAG) and other interested persons concerning eligibility criteria for small business customers in its energy efficiency offerings.[138] Avista will also further explore mirroring residential customer offerings for small

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[134] Settlement at 17-18, ¶ 25.

[135] Brief of Public Counsel at 43-44, ¶ 96; Dahl, Exh. CJD-1T at 31:3-10.

[136] Commissioner Doumit, TR at 146:9-24.

[137] Ehrbar, TR at 147:2-7; McCloy, TR at 147:9-11.

[138] Settlement at 18, ¶ 26.

business customers.[139] The Settlement provides that discussions must begin no later than June 30, 2023, and must include a conversation of budget impacts, which will be funded through Schedules 91 and 191, and a timeline for completing the pursuit of additional program offerings for small business customers no later than December 31, 2023.[140] Public Counsel supports the Settlement's terms regarding small business energy efficiency and believes that they are in the public interest.[141]

Commission Determination

117 We find the Settlement's small business energy efficiency terms appropriate. It is equitable, reasonable, fair, just, and in all cases appropriate that small business customers should be included in considerations regarding how they also can participate in and benefit from energy efficiency efforts. This is both for their benefit as well as Avista's because the Company must maintain compliance with statutory requirements for energy efficiency, conservation, and for providing energy to its customers while reducing GHG emissions. Accordingly, we determine that the terms regarding small business energy efficiency are timely, reasonable, and should be approved.

xiv. Electric Service Reliability Report Plan

118 Avista also agrees that it will include its final electric service reliability reporting plan with the compliance filing in these consolidated proceedings.[142] The Settlement proposes two terms regarding Avista's electric service reliability report plan: first, Avista agrees to clarify its presentation and distinction of "Washington-only" metrics as compared with "system-wide" metrics, including with the presentation and distinction of System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), and Customer Average Interruption Duration Index (CAIDI) performance and historical trends; second, Avista agrees to participate in any multi-party collaborative seeking to establish common measures and reporting formats among Washington's investor-owned utilities for electric distribution system reliability.[143]

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[139] *Id.*

[140] *Id.*

[141] Public Counsel Brief at 43-44, ¶ 96; Dahl, Exh. CJD-1T at 29:16-21.

[142] Settlement at 18, ¶ 27.

[143] *Id.*

Commission Determination

119 We find the Settlement's agreement related to Avista's electric service reliability report plan appropriate. No party opposes this portion of the Settlement. Clarifying and differentiating the metrics of service reliability to exclude Avista's system performance in other states from Washington holds unquestionable value. Service reliability provided by Avista in Idaho or Oregon is only tangentially relevant, due to the unique and different circumstances in those jurisdictions for Avista's service to its customers residing there, for our consideration of the reliability of service provided by Avista to Washington customers. Accordingly, we determine that the Settlement's electric service reliability report plan terms are equitable, reasonable, just, and should be approved.

xv. Miscellaneous Uncontested Terms

120 The Settling Parties agree to several other terms identified in the Settlement as "miscellaneous." We summarize and address these terms together.

a. *Depreciation Rates and Regulatory Amortizations*

121 The Settling Parties agree to terms regarding the depreciation rates and regulatory amortizations as included in Avista's initial filing for certain adjustments, which are detailed in Attachment D to the Settlement.[144] These relate to the amortization of deferrals and remaining balances previously approved by the Commission.[145] Without Commission authorization, the Company would be unable to amortize or depreciate these balances.[146]

b. *Annual Filing Dates*

122 The Settling Parties agree to the proposals in Avista's initial filing to change the rate effective dates for several annual filings. First, the Settling Parties agree to move the annual Schedule 98 Renewable Energy Credit (REC) filing from July 1 to August 1 to coincide with other rate changes.[147] Second, the Settling Parties agree to move the proposed low-income rate assistance program (LIRAP) Schedule 92/192 effective dates

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[144] Settlement at 19, ¶ 28(a); *see* Settlement at Attachment D.

[145] Settlement at 19, ¶ 28(a) and accompanying notes.

[146] *Id.*

[147] Settlement at 19, ¶ 28(b); *see* Miller, Exh. JDM-1T, 34:10-14.

from October 1 to November 1.[148] Last, the Settling Parties agree to move the Wildfire Deferral filing date from July 31 to September 1 and to also move the effective date from October 1 to November 1.[149]

c. *Annual Reporting Obligations of Docket U-210151*[150]

123 Avista agrees to provide recommendations in its initial filing of its next GRC regarding how it will streamline its existing required annual reporting obligations (provided in Docket U-210151).[151] Avista also agrees to provide a detailed matrix of all reporting obligations annually along with a matrix of any recommendations for streamlining, as provided in Docket U-210151.[152]

d. *Software Licensing*

124 Avista agrees to provide templates and vendor contact information for any vendor software licensing agreements, such as Energy Exemplar, with each filing.[153]

e. *Decoupling Earnings Test*

125 The Settling Parties agree to replace the current earnings test with the earnings test provided in RCW 80.28.425(6).[154]

Commission Determination

126 We find the Settlement's miscellaneous terms, described above, appropriate. No party opposes any of the agreements contained in these terms. We find the Settling Parties' agreement to continue authorization of depreciation rates and regulatory amortizations previously authorized by the Commission reasonable. In addition, we find nothing

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[148] Settlement at 19, ¶ 28(b); *see* Bonfield, Exh. SJB-1T, 36:9-17.

[149] Settlement at 19, ¶ 28(b); *see* Andrews, Exh. EMA-1T, 63:6-17.

[150] In error, the Settling Parties refer in the Settlement and in their Joint Testimony to Docket U-210501. Settlement at 19, ¶ 28(c); Joint Testimony, Ext. JT-1T at 40:7-11. The relevant docket is U-210151. We have made this ministerial correction to the Settlement's referenced docket throughout this Order.

[151] Settlement at 19, ¶ 28(c).

[152] *Id.*

[153] Settlement at 19, ¶ 28(d).

[154] Settlement at 19, ¶ 28(e); *see* Ehrbar, Exh. PDE-1T, 37:14-38:25, describing how the existing earnings test conflicts with the earnings test provided in RCW 80.28.425(6).

objectionable to the Settlement's terms allowing Avista to modify certain filing dates and effective dates to create greater efficiencies, those terms encouraging streamlining in reporting obligations, and those requiring the sharing of vendor contact information. Each of these terms are reasonable and will promote greater efficiency for the Commission's regulation and review, as well as that of interested persons. Lastly, recently enacted legislation requires the deferral of earnings that are more than 0.5 percent higher than the ROR authorized by the Commission and reported annually through a company's Commission Basis Report (CBR).[155] The Commission authorizes replacing the existing decoupling earnings test with the earnings test provided in RCW 80.28.425(6). Further, the Commission clarifies that the decoupling deferral must include accruing ROR on the balance of the deferral. Lastly, the Commission determines that Avista should be authorized and required to defer any earnings greater than 0.5 percent above its authorized ROR, consistent with this Order, the Settlement, and RCW 80.28.425(6).

127 Accordingly, we determine that the Settlement's miscellaneous terms – regarding depreciation rates and regulatory amortizations, modifications to filing and effective dates, recommendations for streamlining reporting obligations, sharing of contact information for vendor agreements, and the decoupling earnings test – are reasonable, not contrary to law, in the public interest, and should be approved.

2. POWER COSTS

128 The Settling Parties agree to two terms regarding power costs. First, the Settling Parties agree to accept the 2023 Pro Forma Power Supply expense and Energy Recovery Mechanism (ERM) Baseline included in Avista's initial filing.[156] Second, they agree that Avista will not perform the 60-day power cost updates that it had proposed in its initial filing.[157] Instead, the ERM Baseline will remain as indicated in Avista's initial filing for the duration of the MYRP and is included as Attachment C to the Settlement.[158] Public Counsel generally supports the Settlement's power cost terms.[159] It takes issue, however,

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[155] RCW 80.28.425(6). On April 25, 2022, during the pendency of these consolidated proceedings, Avista filed its 2021 electric and natural gas CBRs in Dockets UE-220288 and UG-220289, respectively, indicating the Company's actual cost of capital as of December 31, 2021.

[156] Settlement at 9, ¶ 15.

[157] *Id.*

[158] *Id.*; *see* Kalich, Exh. CGK-6.

[159] Earle, Exh. RLE-1T at 2:9-10.

with the energy imbalance market (EIM) benefit projections embedded in Avista's initially-filed ERM baseline and revenue requirement because they are based on a 2017 study by Energy and Environmental Economics (2017 E3 Study).[160] Public Counsel, therefore, contests this term of the Settlement and proposes that the Commission either annualize one month of the California Independent System Operator's (CAISO) estimated benefits amounts or direct Avista to update the 2017 E3 Study prior to the effective date in these consolidated proceedings.

Commission Determination

129 We find that the power supply terms proposed by the Settlement are reasonable and supported by the record. To calculate the EIM benefits included in the ERM baseline, Avista relies on the 2017 E3 Study that estimates benefits of approximately $5.8 million on a system basis.[161] Public Counsel argues that the study should not be used to approximate the EIM benefits because the study is denominated in 2017 dollars.[162] Instead, Public Counsel recommends that the study be updated based on actual data from Avista's participation in the market.[163] In the absence of an updated study, Public Counsel recommends using the results from CAISO's benefits estimation. Because only one month of results was available at the time testimony was filed, Public Counsel annualizes one month of benefits to derive an annual amount.[164] Public Counsel's revenue requirement proposal incorporates this alternative position.

130 Public Counsel's preferred proposal is that the 2017 E3 Study be updated using more recent input data.[165] Avista argues in rebuttal that it is impossible for the 2017 E3 Study to be updated before the statutory deadline in these consolidated proceedings.[166] We agree. Directing Avista to update its 2017 E3 Study prior to the effective date of these consolidated proceedings is impractical and we decline to set such a requirement.

131 In the alternative, Public Counsel proposes annualizing the March 2022 EIM benefits from CAISO's benefits study to estimate the benefits in all of 2023. Avista opposes

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[160] *See* Kinney, Exh. SJK-3.

[161] Kinney, Exh. SJK-1T at 8:5-7.

[162] Earle, Exh. RLE-1T at 7:12-16.

[163] *Id.* at 9:18-21.

[164] *Id.* at 10:1-12.

[165] *Id.* at 9:18-10:3.

[166] Kinney, Exh. SJK-13T at 6:13-20.

Public Counsel's proposal, arguing that "[w]ithout any operating experience it is too early for the Company to tell whether the CAISO benefit calculation methodology . . . will accurately reflect estimated benefits for Avista. . . ."[167] Further, at hearing and in prefiled written testimony, Avista witness Kinney explained a number of factors that either influenced CAISO's benefits study in the beginning of 2022 or will present an unknown degree of influence, including the amount of hydro, price volatility, transmission interconnection, availability, the CCA and its potential interaction with California markets, Bonneville's entrance into the EIM market, and a new, long-term power purchase agreement that will begin during the MYRP.[168]

132 We agree with Avista. We find that annualizing amounts into rates based on one month of data is not a sound methodology, cannot account for the unknown influences of a number of factors in 2023, and is more flawed than retaining the current 2017 E3 Study's estimates. Public Counsel's proposal is also problematic due to the uncertain timing of how and when EIM benefits will accrue.

133 While the 2017 E3 Study is not without flaws, its selection by the Settling Parties is supported by the record and reasonably balanced by the terms of the Settlement. The 2017 E3 Study was conducted several years ago, and while supported in this record and that of prior GRCs, the Settlement does not propose any update or comparison with any additional data. We find, however, that the flaws and associated risks of the Settling Parties' selection of the 2017 E3 Study are balanced by Avista's negotiated risk to forgo a 60-day power cost update, which will maintain the power cost level established in Avista's initial filing for the entirety of the MYRP.

134 We accept the Settling Parties' agreement to use the 2017 E3 Study to estimate EIM benefits included in the ERM baseline and reject Public Counsel's proposals to either annualize one month of CAISO's estimated benefits amounts or direct the Company to update the 2017 E3 Study prior to the effective date in these consolidated proceedings. None of the three options advanced are ideal, but the Settlement's proposal is reasonable and a well-balanced resolution to the issue.

135 Further, there is a balance struck by the Settlement between Avista and its customers. Avista argues that Public Counsel "cherry-picks" one element of Avista's power supply levels by updating for a decrease in the ERM baseline, while ignoring updates to different

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[167] *Id.* at 7:2-4.

[168] *Id.* at 3:8-11; Kinney, TR at 295:11-298:14.

offsetting factors that could increase the baseline.[169] We acknowledge the risk Avista explains in testimony that it has agreed to as part of the give and take of negotiations. In addition, we agree that the Settling Parties have reached a balanced result with shared risk and some protection for both the Company and its customers, via the ERM, should power supply components vary from the baseline levels.[170]

136 Ultimately, we find that in lieu of using a more recent or updated benefits study, Avista's agreement to incur additional risk by agreeing to not include a 60-day power cost update prior to new rates going into effect for each year of the MYRP is supported by the record and is a fair, reasonable, and balanced resolution of this issue. Accordingly, we determine that the Settlement's power costs terms are in the public interest and should be approved.

3. INSURANCE BALANCING ACCOUNT

137 The Settling Parties agree to two balancing accounts: a Wildfire Expense Balancing Account; and an Insurance Expense Balancing Account.[171] We address the former later in this Order, along with other wildfire-related issues.

138 The Settling Parties agree to the proposal in Avista's initial filing to create an Insurance Expense Balancing Account for the MYRP.[172] The Settling Parties recognize that Avista will bear the burden of supporting deferrals for the account when seeking recovery in a future rate proceeding.[173] The Settling Parties specify that the establishment of an Insurance Expense Balancing Account is not precedential and its continued existence may be challenged by any party in a future proceeding.[174] The Insurance Balancing Account Baseline over the MYRP will be approximately $8.3 million for electric and $1.7 million for natural gas.[175]

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[169] Kinney, Exh. SJK-13T at 4:3-7.

[170] *See id.* at 2:10-3:23.

[171] Settlement at 9, ¶ 16.

[172] Settlement at 9, ¶ 16(b).

[173] *Id.*

[174] *Id.*

[175] Joint Testimony, Exh. JT-1T at 25:7-11; Andrews, Exh, EMA-1T at 64:23; Coppola, Exh. SC-6Cr (Public Counsel Data Request No. 103C).

139 Public Counsel opposes the creation of an insurance balancing account, including any establishment of a baseline.[176] Instead of the Settlement's proposal to accept Avista's expected insurance expense amounts of approximately $8.3 million for electric and $1.7 million for natural gas for each year of the MYRP and use them to establish a baseline for the balancing account, Public Counsel proposes to identify its own insurance expense adjustment within the revenue requirement authorized in this GRC but not allow that amount to be used as a baseline in a balancing account.[177] We address Public Counsel's expense adjustment later in this Order, in our discussion of the Settlement's agreed revenue requirement, but as part of our consideration of the Settlement's insurance balancing account terms we note the amounts presented by Public Counsel in this section.

Commission Determination

140 We find the Settlement's terms establishing a non-precedential Insurance Balancing Account appropriate, subject to a documenting and reporting condition. We agree with the principle underpinning Public Counsel's opposition to the creation of the Insurance Balancing Account: generally, authorizing a pass-through such that a company is guaranteed recovery of its costs in a certain area removes the business incentive for the company to control those costs. However, we find that the record supports the creation of an Insurance Balancing Account, as agreed to in the Settlement, in particular because of the unique circumstances and terms presented.

141 Namely, we find that Avista has demonstrated unprecedented increases and volatility in its insurance costs.[178] We agree that Avista has shown the insurance expense increases in recent years are "extraordinary" and "volatile" and caused an under-recovery of approximately $5.3 million in 2022.[179] We also find that Avista has demonstrated that it has taken and is taking appropriate steps to try to control these costs, but has shown unprecedented recent increases in insurance that are largely out of its control. These increases have been driven primarily by the Company's general liability premiums, which cover wildfire risk and property insurance premiums, and which tend to react to insurance industry losses due to natural disasters.[180] In addition, we agree that these costs

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[176] Brief of Public Counsel at 17, ¶ 35; Coppola, Exh. SC-1T at 24:19.

[177] *See* Coppola, Exh. SC-1T at 23:15-24:16; Coppola, Exh. SC-8.

[178] This results from significant increases in insurance expenses in recent years, which have increased approximately 107 percent from 2020 to 2022. Andrews, Exh. EMA-7T 25:16-18.

[179] Andrews, Exh. EMA-1T at 66:16-19 and Exh. EMA-7T 28:5-11.

[180] *See* Andrews, EMA-1T at 64:2-74:19; Brandkamp, Exh. REB-1CT at 3:22-8:12.

have increased due to factors outside the Company's control and despite the Company's best efforts under its Wildfire Resiliency Plan.[181]

142 We also observe that the amounts proposed as a baseline by the Settlement and as insurance expense calculated by Public Counsel are similar,[182] but find that Public Counsel's methodology would present risks, flaws, and precedent that strongly disfavor its adoption. Public Counsel disagrees with Avista's method of projecting its insurance expense, preferring to use a Consumer Price Index (CPI) inflation factor.[183] We are unpersuaded by Public Counsel's arguments to adopt an unrelated inflation factor to calculate projections for insurance costs during the MYRP. Public Counsel's proposal to use inflation factors projecting growth in this area is incongruous with its support for the Settlement's terms excluding escalation factors projecting growth – a portion of the Settlement supported by all parties. In addition, as Avista notes in the record, the insurance market does not generally correlate with CPI factors, as shown by increases in recent years.[184]

143 Conversely, Avista's estimates are based on consultations with insurance brokers to identify overall trends and projected movements in future premiums in the industry.[185] We agree with Avista that the inflation factors projecting growth in this area are unrelated to insurance or utility costs and have no bearing on the insurance risks being borne by Avista or its expected insurance premiums.[186] The Settlement proposes a balancing account baseline representing increases to Avista's total system invoiced 2022 insurance levels of 12.9 percent (electric and natural gas). After allocation, this results in an increase of 6.7 percent (WA electric) and 0.6 percent (WA natural gas) above invoiced 2022 levels.[187] Public Counsel proposes increases to Avista's total system invoiced 2022 insurance expense levels during the MYRP of 2.4 percent (electric and natural gas) in 2023 and 2.3 percent (electric and natural gas) in 2024.[188] Thus, we find the method supported by Avista and the Settlement to establish the Insurance Balancing Account

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[181] Andrews, Exh. EMA-1T at 67:16-68:2.

[182] *Compare* Coppola, Exh. SC-8 *with* Coppola, Exh. SC-6Cr.

[183] Coppola, Exh. SC-1T at 22:1-20.

[184] Forsyth, Exh. GDF-3T at 9:24-10:3.

[185] Brandkamp, Exh. REB-1CT at 3:22-4:6; Andrews, Exh. EMA-7T at 27:7-10.

[186] Andrews, Exh. EMA-7T at 27:15-28:2.

[187] *See* Coppola, Exh. SC-6Cr.

[188] Coppola, Exh. SC-1T at 23:17-24:16; Coppola, Exh. SC-8.

baseline is appropriate, and the method proposed by Public Counsel for calculating the insurance expense, or to substitute it as the baseline, is not.

144 Last, we find that the Settlement reasonably addresses the concerns from both perspectives as it counterbalances the creation of the account as a protection for both customers and the Company as well as with non-precedential treatment and a limited timeframe of two years. The proposed balancing account would protect ratepayers and the Company from over- or under-collection, by deferring actual insurance expense above or below the baseline amount (the amount included in base rates), similar to that approved in the 2020 Avista GRC for the Company's wildfire expense balancing account. The deferred accounting mechanism would ensure that customers pay no more and no less than the actual expenses incurred over the two-year rate plan. Recovery or refund of any deferred balance would be made through an annual compliance filing beginning September 1, 2023, to become effective November 1, 2023, where the insurance expense deferred balance as of July 31 would be rebated or surcharged through a separate tariff.

145 We emphasize that this is not precedential, but for this case only, and the authorization granted by this Order will cease at the conclusion of the MYRP. In addition, we find a condition necessary to underpin and safeguard the delicate balance in this term of the Settlement to ensure Avista will continue to seek the best insurance at the best price and any savings below the baseline will be returned to customers.

146 Accordingly, we determine that approval of the Settlement should be conditioned on a modification to this term to ensure Avista takes appropriate action to negotiate and attain the best insurance at the lowest costs.

> **Condition.** We condition our approval of the Settlement on the modification of this term to include the requirement that Avista document its action to seek out, negotiate, and attain the best insurance at the lowest costs and file with the Commission such documentation, with explanatory narratives, in Avista's annual filing beginning September 1, 2023. Subject to this condition, we determine that the Settling Parties' agreement to create an Insurance Balancing Account, including the proposed baselines for electric and natural gas, is in the public interest and should be approved.

4. WILDFIRE

147 As previously discussed, the Settling Parties agree to 16 performance metrics related to wildfires and to move the filing date for the Wildfire Deferral from July 31 to September 1 as well as the effective date for the Wildfire Deferral from October 1 to November 1.[189] In addition to these terms already discussed, the Settling Parties agree to accept Avista's proposal to update its Wildfire Expense Balancing Account baseline to $5.1 million, as initially filed by Avista, for the duration of the MYRP.[190]

148 Public Counsel does not oppose any of the above terms of the Settlement. Instead, Public Counsel proposes several general modifications to Avista's Wildfire Plan. In particular, Public Counsel recommends that the Commission require Avista to clarify the definitions, purpose, and cost basis of wildfire activities in order to provide the Commission and ratepayers information on what wildfire activities customers are paying for with supporting evidence for cost recovery.[191] Public Counsel also proposes adjustments to decrement wildfire expenses and capital additions.[192]

Commission Determination

149 Public Counsel proposes revenue requirement adjustments to Avista's wildfire expenses and capital additions.[193] While the Settling Parties agree to update the Wildfire Balancing Account baseline, the Settlement does not accept Avista's initially-filed proposals related to wildfire adjustments for purposes of calculating an agreed revenue requirement.[194] We find it sufficient and appropriate, therefore, to further address Public Counsel's proposed adjustments to Avista's wildfire expenses and capital additions only as part of this Order's discussion of the Settlement's revenue requirement agreements.[195] Below, we turn to Avista's Wildfire Resiliency Plan and Public Counsel's proposed modifications.

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[189] *Supra* Sections A.1.x., A.1.xv.b.

[190] Settlement at 9, ¶ 16(a) and accompanying notes; *see* Andrews, Exh. EMA-1T, 57:16-59:17.

[191] Tam, Exh AT-1T at 11:19-12:2.

[192] Tam, Exh. AT-1T at 10:16-19; Coppola, Exh. SC-1CT at 25:22-26:19, 80:9-12.

[193] *See* Brief of Public Counsel at 19, 33-34, ¶¶ 40, 74-75; Tam, Exh. AT-1T at 10:16-19; Coppola, Exh. SC-1CT at 25:22-26:19, 80:9-12.

[194] *See* Settlement at 4-5, 9, ¶¶ 10, 16(a).

[195] *See infra,* Section A.6.

150 We find the Settlement's wildfire-related terms appropriate and find insufficient cause to condition our approval of these terms. Avista's Wildfire Resiliency Plan was first published in May of 2020. It has four major categories: grid hardening, enhanced risk-based vegetation management practices, grid control and monitoring technology and use of Dry Land Mode, and emergency operations and planning.[196] In the 2020 Avista GRC Final Order, the Commission approved a two-way balancing account to track variability in wildfire expenses, setting the initial baseline at $3.065 million.[197] The Settlement proposes to update the account's baseline to $5.1 million for the duration of the MYRP.[198]

151 Public Counsel recommends that the Commission require several changes to Avista's Wildfire Resiliency Plan to "clarify the use and definitions of terminology and purpose of activities; improve risk and fire event tracking; add reliability metrics; and improve communications, outreach, and stakeholder collaboration with a clear communications and outreach plan with associated metrics."[199] Regarding terminology, Public Counsel requests that the Commission issue specific guidance, in these consolidated proceedings or in Docket U-210254, regarding wildfire plan elements including a glossary of terms for standardization purposes.[200] Public Counsel further asserts that Avista could improve mitigation components of the Plan by having the Company specify the exact purpose of each wildfire program component and what risk each component attempts to mitigate.[201] Public Counsel recommends that Avista track and report additional wildfire metrics related to risk events, ignition events, reliability, and communications and outreach.[202]

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[196] Howell, Exh. DRH-1T at 7:10-20.

[197] 2020 Avista GRC Final Order at 81-91, ¶¶ 231-259 and accompanying notes; Joint Testimony, Exh. JT-1T at 24:5-8.

[198] Settlement at 9, ¶ 16(a) and accompanying notes.

[199] Public Counsel Brief at 38-39, ¶ 85; Tam, Exh AT-1T at 11:19-12:2. As the Commission has become aware that the term "stakeholder" is non-inclusive and historically problematic, we are working to substitute terms like "interested persons," "participants," "persons," or "non-company parties," depending on the situation. We urge others to do the same.

[200] Public Counsel Brief at 39, ¶ 86; Tam, Exh AT-1T at 16:11-16.

[201] Public Counsel Brief at 40, ¶ 87; Tam, Exh AT-1T at 16:19-20.

[202] Public Counsel Brief at 40-43, ¶¶ 88-95; Tam, Exh AT-1T at 30:17-31:9; 32:7-9; 37:13-39. Public Counsel's requests include one that the Commission adopt best practices from "California Energy Safety and issue specific guidance in Docket U-210254 which should include uniform, regular risk event and ignition reporting requirements across all Washington investor-owned utilities." Brief of Public Counsel at 41, ¶ 90; *see* Tam, Exh. AT-1T at 31:17-32:4.

152 Avista indicates that it will be incorporating many of Public Counsel's recommendations as helpful and constructive improvements.[203] Avista agrees to add a glossary of terms into its reports and will make an effort to use the same terminology in most wildfire documents to promote consistency and understanding.[204] In addition, Avista contends it cannot enforce standardization of terminologies with other utilities, but agrees to be open to updating, improving, and refining its own definitions and descriptions in light of these interactions.[205] Avista also updated and provided a new table to better describe how programs will mitigate wildfires, detailing the work category, program, primary purpose, and mitigation value.[206] Avista provided a second table to detail the distributed grid hardening treatment with the risk reduction outcome expected.[207]

153 For Public Counsel's other critiques, Avista responds that it is either currently working on or improving numerous aspects of its Wildfire Resiliency Plan, including: equipment replacement; wildfire metrics for performance measures; tracking of pole fires and fiberglass cross-arm replacements alongside each other; limitations of existing Outage Management System; the need for geographic tracking of risk events and ignitions; additional metrics used by California utilities; tracking of outages and ignitions from trees outside the utility corridor; tracking outages during different Dry Land Mode settings; tracking wildfire-related communication and outreach metrics; improve Access and Functional Needs outreach; provide translated wildfire-related materials; and engaging with community-based organizations related to special-needs and limited English proficiency customers.[208] Avista explains that some of the improvement areas are due to technical constraints during the transition of new programs.

154 We are satisfied with Public Counsel's and Avista's dialogue in these consolidated proceedings and Avista's adoption of many of Public Counsel's recommendations. We find that the record demonstrates Avista's openness to feedback and willingness to adopt constructive suggestions. Many of Public Counsel's suggestions have either already been adopted or will be adopted by Avista when technically feasible. We decline to require or condition approval of the Settlement upon Avista adopting additional proposals but

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[203] Howell, Exh. DRH-5T at 3:18-22.

[204] *Id.* at 3:23-27, and 26:6-9.

[205] *Id.* at 26:14-27:6.

[206] *Id.* at 28:1-23.

[207] *Id.* at 29:1-30:1.

[208] *Id.* at 3:18-27, 10:4-15:9; 16:1-19:14; 21:15-25:22; 26:6-27:6; 28:1-37:20.

expect Avista to remain open to more improvements going forward and to continue its involvement and participation in Docket U-210254, which is a more appropriate forum for pursuing many of Public Counsel's recommendations.[209] We encourage Public Counsel to redeliver its suggestions and recommendations, in particular those that have universal effect for Washington's investor-owned utilities, in Docket U-210254 to help promote, among other things, standardization of wildfire terminology and risk event and ignition reporting concerns that might aid further development of utility preparedness.

155 Accordingly, we determine that the Settlement's wildfire terms, exclusive of the expense and capital additions that we include in our discussion of the Settlement's revenue requirement terms, should be approved without condition.

5. COST OF CAPITAL

156 The Settling Parties agree to an ROR of 7.03 percent for both years covered by the Settlement.[210] Like the revenue requirement for both electric and natural gas operations discussed later in this Order, this term of the settlement is a results-only agreement. The Settlement identifies no component of the cost of capital used to calculate the agreed ROR, namely: return on equity (ROE), cost of debt, and capital structure. In a footnote to their joint testimony (Footnote 8), however, the Settling Parties provide hypothetical components illustrating how the agreed ROR "could be derived using Avista's currently-authorized Return on Equity of 9.4 percent, 48.5 percent equity layer, 51.5 percent debt layer, and a 4.8 percent cost of debt that was updated during the case."[211] The Settling Parties state that this would produce "a result within the zone of reasonableness."[212]

157 Public Counsel opposes the Settlement's proposed ROR of 7.03 percent. In addition, Public Counsel opposes all hypothetical components of the proposed ROR that are implied by Footnote 8: the capital structure, ROE, and cost of debt. Table 6, below, illustrates Avista's currently authorized cost of capital, Avista's actual cost of capital reported to the Commission in its 2021 Commission Basis Report, and the cost of capital positions presented in this proceeding.

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[209] Docket U-210254 is the Commission's docket for utility wildfire preparedness.

[210] Settlement at 5, ¶ 11.

[211] Joint Testimony, Exh. JT-1T at 14, n. 8.

[212] *Id.*

Table 6. Cost of Capital Positions

Component	Current	Settlement	Public Counsel	*Initial Filing*[213]	*2021 CBR*[214]	*Footnote 8* [215]
Equity	48.5 %	-	45.6 %	*48.5 %*	*47.56%*	*48.5 %*
ROE	9.4 %	-	8.75%	*10.25%*	*9.4 %*	*9.4 %*
Weighted Cost	4.56%	-	3.99%	*4.97%*	*4.47%*	*4.56%*
Debt	51.5 %	-	54.4 %	*51.5 %*	*52.44%*	*51.5 %*
Cost	4.97%	-	4.54%	*4.54%*	*4.78%*	*4.8 %*
Weighted Cost	2.56%	-	2.47%	*2.34%*	*2.51%*	*2.47%*
ROR	**7.12%**	**7.03%**	**6.46%**	*7.31%*	*6.98%*	*7.03%*

Commission Determination

158 We find the Settlement's agreed ROR of 7.03 percent appropriate. The record supports the cost of capital terms agreed by the Settling Parties and we find that the Settlement's agreed ROR falls within a range of reasonableness. In this case, the Commission received three cost of capital testimonies: Avista's initial testimony, Public Counsel's opposition testimony, and the Settling Parties' rebuttal testimony (Avista's witnesses).[216] Ultimately, we find that the Settlement's agreed ROR is supported by the record and falls within a

[213] With its support of the Settlement and the Settling Parties' proposal to a results-only ROR of 7.03 percent, Avista no longer supports the testimony and evidence it initially filed regarding cost of capital.

[214] *See* Avista's 2021 Electric & Natural Gas CBRs, Dockets UE-220288 and UG-220289 (Apr. 25, 2022).

[215] The cost of capital elements provided as hypothetical illustration only are not agreed to by the Settling Parties and are not included as a term in the Settlement. Settling Parties provide the information in Footnote 8 only as a hypothetical illustration of how the ROR *could be derived* using Avista's currently authorized capital structure, ROE, and updated cost of debt. *See* Response to BR-7.

[216] *See, e.g.,* Garrett, Exh. DJG-1T at 9:1-12, stating "In my opinion, an authorized ROE greater than the 8.75 percent ROE I recommend would be unreasonable." *See, e.g.,* McKenzie, Exh. AMM-1T at 6:1-4, stating "Based on the results of my analyses shown on Exh. AMM-4, and giving less weight to extremes at the high and low ends of the range, I conclude that the cost of equity for the proxy group of utilities is in the 9.5 percent to 10.9 percent range."

range of reasonableness and find Public Counsel's arguments unconvincing that the agreed ROR is unsupported and unreasonable.

159 Public Counsel's arguments regarding cost of capital, like most of its opposition testimony, are presented in contrast to Avista's initial filing. Specifically, Public Counsel focuses its testimony on components of cost of capital not specified in the Settling Parties' agreement. Public Counsel's argument might have been more persuasive if it were focused more on its opposition to the Settlement terms that we must evaluate.[217] Public Counsel's proposed cost of capital would reduce the initial filing's revenue requirement in the first rate year by $23.0 million for electric and $5.8 million for natural gas, and in the second rate year by $0.9 million for electric and $0.2 million for natural gas.[218] Public Counsel's direct recommendation regarding the Settlement's ROR is that the Commission should reject it because it fails to reduce the initial filing's revenue requirement *as much as* Public Counsel's.[219] We find this argument unpersuasive.

160 Public Counsel focuses its arguments on ROE and capital structure, while accepting the initial filing's cost of debt. Public Counsel witness Garrett argues that the agreed ROR is unreasonable because it is derived from an implied ROE of 9.68 percent.[220] Garrett also argues that the level of equity in the capital structure proposed by Avista in its initial filing is too high.[221] Again these arguments focus opposition on Avista's initial filing, instead of the Settlement, which is what we must evaluate and consider. This flaw is particularly fatal given the lack of ROE, capital structure, or cost of debt enumerated in

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[217] Public Counsel witness Coppola testifies that

> Public Counsel's lower cost of capital represents the largest adjustment to Avista's proposed revenue requirement, reflecting primarily the excessive ROE rate of 10.25 percent the Company proposed and an inflated equity ratio of 48.5 percent. The Commission should not accept the Company's overstated rate of return, and instead should accept Public Counsel's proposed overall cost of capital . . . .

Coppola, Exh. SC-1CT at 16:13-14.

[218] *Id.* at 16:4-7.

[219] The Settlement ROR would reduce the initial filing's revenue requirement in the first rate year by only $7.6 million for electric and $1.9 million for natural gas, and in the second rate year by only $0.3 million for electric and $0.1 million for natural gas. *Id.* at 16:18-17:8.

[220] Garrett, Exh. DJG-1T at 9:1-4; 15, Figure 3. Garrett uses Avista's currently authorized capital structure and the cost of debt in the initial filing. *Id.* Garrett also argues that an ROE of 9.4 percent is unreasonable. *Id.* at 56:3-14.

[221] *See* Garrett, Exh. DJG-1T at 57:2-64:7.

the Settlement. The only element of cost of capital agreed by the Settling Parties is the resulting ROR, which they present as a fair end result that falls within the range of reasonableness supported by the testimony in these consolidated proceedings and as the result of a negotiated settlement. Nevertheless, we examine the evidence presented by Public Counsel and explain our determinations.

161 Public Counsel employs CAPM and DCF models supporting ROE results of 7.5 percent and 8.3 percent.[222] Avista witness McKenzie, on behalf of the Settling Parties, critiques Public Counsel's analyses, arguing that they misapply risk philosophies and are undermined by methodological flaws.[223] We agree and note, first, flaws with Public Counsel's over reliance on long-term forecast of Gross Domestic Product (GDP) from the Congressional Budget Office (CBO) due to CBO's own characterization of its projections as "very uncertain" and exacerbated by the unknown effects of the pandemic, and, second, Public Counsel's reliance on a market risk premium based upon the assumption that a long term growth rate would equal the then-current yield on United States' Treasury bonds.[224] During these consolidated proceedings, the CIP inflation increased to over 9 percent.[225] In part due to changing economic conditions since its filed testimony, Public Counsel's proposals based upon assumptions of a 3.8 percent nominal growth rate are simply too tenuous to be persuasive.[226] Thus, we determine the Settlement's agreed ROR should not be modified based upon Public Counsel's ROE arguments and proposal.

162 We are likewise unpersuaded by Public Counsel's arguments that the Settlement's agreed ROR should be modified by Public Counsel's proposed capital structure. Public Counsel recommends a capital structure with an equity ratio of 45.6 percent, which is less than Avista's current authorized ratio of 48.5 percent.[227] Public Counsel argues that a utility, like Avista, would have an incentive to keep less equity and fund its operations with a greater portion of debt than reflected in its authorized capital structure because equity

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[222] Garrett, Exh. DJG-1T at 56:4-6.

[223] McKenzie, Exh. AMM-15T at 5:6-10, 25:6-13, 26:3-28:8, 32:3-36:16, 37:7-38:2, 47:15-48:1; Ehrbar, Exh. PDE-2T at 4:9-11.

[224] *See* Garrett, Exh. DJG-1T at 36:3-46:21, 50:11-53:12; Garrett, Exh. DJG-6, Garrett, Exh. DJG-8; McKenzie, Exh. AMM-15T at 35:10-36:2, 39:5-13.

[225] McKenzie, Exh. AMM-15T at 8:15-19.

[226] *See id.*; Garrett, Exh. DJG-1T at 43:3-44:4; McKenzie, Exh. AMM-15T at 35:19-36:2 and accompanying notes.

[227] Garrett, Exh. DJG-1T at 64:9-11.

receives a larger return than debt, and debt has a lower cost.[228] We are reassured by testimony supporting the Settlement that establishes Avista's intent and practice of maintaining a level of equity near its authorized level. We find no concern at this time that Avista is manipulating its level of equity in the ways Public Counsel says are possible.[229] Further, due to the terms' results-only nature, the level of equity and debt is undefined and, therefore, impossible for us to determine without upsetting the Settlement. In addition, Avista's recent CBRs add support to the conclusion that Avista is not at this time manipulating its authorized level of equity. The CBRs show the Company's actual equity ratio as of December 31, 2021, at 47.56 percent, which is closer to Avista's authorized equity ratio than Public Counsel's proposed equity ratio.[230] Thus, we determine the Settlement's agreed ROR should not be modified based on Public Counsel's capital structure proposal.

163 The resulting ROR that Public Counsel recommends is 6.46 percent and would represent a 66 basis point decrement upon Avista's currently-authorized ROR if adopted.[231] Public Counsel's recommendation is based upon a 7.9 percent ROE, 4.45 percent cost of debt, and an equity ratio of 45.6 percent. The Settling Parties argue that Public Counsel's proposal is unreasonably low. Avista witness McKenzie, on behalf of the Settling Parties, provides the most updated five-year average ROE of 9.44 percent and a median of 9.49 percent approved by state utility commissions.[232] With this context, the Settling Parties argue that Public Counsel's estimate of Avista's cost of equity as 7.9 percent is not credible, fails to meet accepted benchmarks, and would be an extreme result falling "far below the lowest ROE awarded by any state regulatory commission in modern history."[233] We agree, but recognize that basing our approval of ROE on the results of other state utility commissions represents a circular and self-fulfilling argument because those commissions may be making decisions the same way. Public Counsel's recommendation to set an ROR of 6.46 percent based, in part, upon decrementing Avista's currently authorized ROE by approximately 150 basis points below the average

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[228] *See* Garrett, Exh. DJG-1T at 56:16-60:15.

[229] Thies, TR at 433:7-438:2.

[230] *See* Avista's 2021 Electric & Natural Gas CBRs, Dockets UE-220288 and UG-220289 (Apr. 25, 2022).

[231] Garrett, Exh. DJG-1T at 3:1–7; Coppola, Exh. SC-1CT at 11:3-4.

[232] McKenzie, Exh. AMM-15T at 5:3-5. McKenzie's data is taken from S&P Global Market Intelligence, Major Rate Case Decisions – January-June 2022.

[233] Ehrbar, Exh. PDE-2T at 3:19-24 (citing McKenzie, Exh. AMM-15T); *see* McKenzie, Exh. AMM-15T at 4:11-19:9.

allowed ROE for other electric utilities in the first half of 2022 would be a shock to Avista's financial integrity and impact its ability to attract capital on reasonable terms.[234] The record's demonstrated and explained economic circumstances scarcely justify any consideration of authorizing an unprecedented decrement to Avista's authorized ROR. Ultimately, we find Public Counsel's analyses and recommendations unconvincing and unpersuasive because they are too speculative and unreliable.

164 ROR is the most important element of cost of capital for regulatory purposes. For example, the ROR is reported in Avista's annual CBR and used in Avista's decoupling mechanism to trigger a refund to customers. Prior to this GRC, that earnings test would return half the Company's earnings that exceeded its authorized ROR (currently 7.12 percent).[235] The Settlement replaces this earnings test with language from RCW 80.28.425(6), triggering a refund to customers of *all* earnings more than one-half percent above Avista's authorized ROR.[236]

165 The Settlement's agreement would reduce Avista's currently authorized ROR from 7.31 percent to 7.03 percent. Using Avista's currently authorized ROR would create a refund threshold of 7.81 percent, but the Settlement lowers the threshold for a refund of *all* earnings to 7.53 percent. While the Settlement increases Avista's revenue requirement, the agreed decrement to Avista's ROR is a gradual step that benefits Avista's ratepayers. The give and take of the Settling Parties through negotiation of this term is, therefore, readily apparent in achieving a fair balance of opposing interests. Accordingly, we determine that the Settlement's agreed ROR is a fair end result that falls within a range of reasonableness, that it is supported by the record, and that it should be approved.

6. OVERALL REVENUE REQUIREMENT

166 As described above in Table 1, Avista proposed in its initial filing an annual revenue increase for Rate Year 1 for its electric operations of approximately $52.9 million, or 9.6 percent, and for its natural gas operations of approximately $10.9 million, or 9.5 percent. For Rate Year 2, Avista proposed an annual revenue increase for its electric operations of

[234] *See* McKenzie, Exh. AMM-15T at 20:18-21:21.

[235] Avista Tariff Schedules 75 (electric) and 175 (natural gas).

[236] Settlement at 20, ¶ 28(e); Ehrbar, Exh. PDE-1T at 37:14-38:24. One-half percent above the agreed ROR of 7.03 percent.

approximately $17.1 million, or 2.8 percent, and an increase for its natural gas operations of $2.2 million, or 1.7 percent.[237]

167 The Settlement provides for a $38.0 million annual increase to Avista's electric revenues, and a $7.5 million annual increase to its natural gas revenues in Rate Year 1. In Rate Year 2, the Settling Parties agree to an additional $12.5 million annual increase to Avista's electric revenues, and $1.5 million to its natural gas revenues.[238] The Settlement also includes a proposal to return the Residual Tax Customer Credit of $25.5 million for electric (approximately $12.8 million annually) and of $12.5 million for natural gas (approximately $6.3 million annually) to partially offset the revenue increases.

168 The Settling Parties' agreement regarding Avista's revenue requirement during the MYRP is a "results-only" settlement.[239] The Settling Parties agree that the overall resulting rate increases in the MYRP are equitable, fair, just, reasonable, and sufficient, and with the exception of certain items (*e.g.*, ROR), do not agree to any specific adjustments necessary to reach the agreed revenue requirement. Specifically, no individual adjustments made to net operating income or rate base were enumerated to calculate the revenue requirement. The parties attest that the results-only Settlement represents a give-and-take on multiple issues that characterizes settlement discussions and reflects a reasonable balance of differing interests.[240]

169 While Public Counsel accepts nearly all the Settlement's terms, it contests the overall revenue requirement and argues that the Commission should adopt a revenue requirement that relies on its adjustments to the revenue requirement models presented in Avista's initial filing.

170 In general, the revenue requirement is the increase or decrease in additional or reduced annual revenue derived from a calculation using a modified historical test year based on

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[237] Vermillion, Exh. DPV-1T at 18:11-17.

[238] Joint Testimony, Exh. JT-1T at 2:15-22.

[239] Previously, the Commission has described such agreements as "black-box" settlements. However, as we have become aware that this description has negative connotations that reinforce anti-Blackness by using colorist language, we intend to reference such agreements as "results-only" or "results-focused" settlements. Similarly, as noted above, we intend to substitute for the historically problematic term "stakeholder" terms such as "interested persons," "participants," "persons," or "non-company parties," depending on the situation. We urge parties before the Commission to adopt the same or similarly informed and updated language.

[240] Joint Testimony, Exh. JT-1T at 12:3-9.

adjustments to a company's currently authorized ROR to its rate base, expenses, and revenues. A results-focused Settlement means that its revenue requirement components are neither articulated in a way that allows others to reproduce the calculation nor identified for purposes of allowing any numerical increase or decrease.

171 Table 7, below, summarizes the revenue requirement proposals and adjustments presented by Avista's initial filing, Public Counsel's opposition testimony, and the Settlement.

172 **Table 7. Revenue Requirement Summary (*before* Residual Tax Customer Credit)**
(in millions)

Position		**Electric**		**Natural Gas**	
		Rate Year 1	Rate Year 2	Rate Year 1	Rate Year 2
Initial Filing		**$ 52.9**	**$ 17.1**	**$ 10.9**	**$ 2.2**
Public Counsel Adjustments to Initial Filing	*ROR Reduction*	*$ (23.0)*	*$ (0.9)*	*$ (5.8)*	*$ (0.3)*
	O&M Reductions	$ (10.4)	$ (4.9)	$ (2.1)	$ (0.9)
	Rate Base Reductions	$ (7.2)	$ (8.7)	$ (1.4)	$ (0.8)
	O&M Offsets Reversal	$ 0.2	$ (0.2)	$ (0.04)	$ (0.01)
	EIM Benefit	$ (12.1)	-	-	-
Public Counsel		**$ 0.4**	**$ 2.8**	**$ 1.7**	**$ 0.2**
Settlement		**$ 38.0**	**$ 12.5**	**$ 7.5**	**$ 1.5**

Commission Determination

173 Ultimately, we find the revenue requirement Settlement terms balance appropriately with all terms of the Settlement, are supported by the record, and result in rates across the MYRP that are equitable, fair, just, reasonable, and sufficient. We are not troubled by the results-only nature of the Settlement's revenue requirement terms. Results-only revenue requirement agreements that propose fair and just end results without specifying most, or any, underlying adjustments used to arrive at the resulting revenue requirement would be troubling only if the record, and Settlement, lacked sufficient support demonstrating that

the revenue requirement are equitable, fair, just, reasonable, and sufficient. Here, the Settlement's terms are supported sufficiently, including explanations of the delicate balance struck between the Settling Parties in consideration of the revenue requirement and the non-revenue related terms.

174 In evaluating settlements, we consider the entire record. Here, the record for our consideration includes all initial testimony and exhibits, the Settlement and supporting testimony and exhibits, and the testimony and exhibits opposing the Settlement. The Settlement's proposed revenue requirement provide no indications as to any adjustment that may be included in or excluded from the resulting revenue requirement calculations. Considering Public Counsel's opposition, this has two consequences. First, a results-only revenue requirement provides approval for no investment or adjustment for which Avista sought recovery in this case. By approving the proposed revenue requirement, the rate base approved in Avista's most recent rate case remains undisturbed and no determination relating to prudence or any party's proposed adjustments would be affected.

175 Second, should we agree with Public Counsel on any of its proposed adjustments to the revenue requirement, we would be unable to identify whether the adjustment advocated for had already been incorporated into and made part of the results-only revenue requirement terms and would, therefore, be unable to effectuate any single adjustment. Taking into consideration our rejection of Public Counsel's cost of capital proposals, the revenue requirement proposed by Public Counsel is similar enough to the agreed revenue requirement that it could be calculated by selecting and rejecting some, but not all, of Public Counsel's adjustments. This illustrates the probability that some, but perhaps not all, of the considerations raised by Public Counsel to arrive at its proposed revenue requirement may already have been considered by the Settling Parties. We cannot, however, speculate upon which issues the Settling Parties entered into negotiated agreements and, ultimately, determined to resolve their further disputes by agreeing to the results-only revenue requirement. All the Settling Parties agree the revenue requirement amounts are fair even if they are unable to enumerate the specific adjustments agreed to in order to arrive at the fair, just, and reasonable end results.

176 This is different and distinct from our recent Cascade Final Order. That case presented a settlement that adopted much of the company's initial filing, including the enumeration of adjustments to arrive at an agreed revenue requirement. The Commission was able to determine in that case which revenue requirement adjustments the settling parties adopted that could be modified. Here, we cannot. Instead, we must consider the aggregate and

whether the results-only revenue requirement to which the Settling Parties agreed represents, when considered as part of the Settlement as a whole and balanced by the numerous non-revenue terms, a fair, just, and reasonable end result. Here, we determine that the end-results revenue requirement is supported by an appropriate record and, in the context of the entirety of the Settlement, is in the public interest and should be approved. We explain in greater detail, below.

177 Rather than responding to the merits of the resulting revenue requirement in the context of the entire Settlement, which contains many terms Public Counsel asserts are in the public interest, Public Counsel responds primarily to the merits of the proposals and adjustments presented in Avista's initial testimony, relying on its adjustments to Avista's revenue requirement models to present its own revenue requirement recommendations. Public Counsel's proposed revenue requirement reductions stem from adjustments to the Settlement's cost of capital, which we have previously addressed in this Order, eight expense items in the Company's initial filing, and 16 capital additions included in the Company's initial filing.

178 The specific expense items Public Counsel recommends adjusting are: Insurance Expense, Vegetation Management, Customer Service Expense, Pension Expense and Other Post-Employment Benefits Expense, Miscellaneous Operations and Maintenance Expense, Information Systems and Information Technology Expense, and CETA Labor Expense.[241] The capital additions Public Counsel recommends adjusting are: Distribution Management System, Gas Non-Revenue Program, EV Transportation, Customer Experience Platform, Customer Transaction Systems, Distribution System Enhancements, Electric Relocation and Replacement Program, Energy Delivery Modernization, Energy Resources Modernization, Gas Aldyl-A Pipe Replacement Program, Gas Meter Change Program, Substation – New Distribution Station Capacity Program, Substation – Station Rebuilds Program, Wildfire Resiliency Plan, Wood Pole Management, and Enterprise and Control Network Infrastructure.[242]

179 Public Counsel opposes the Settlement's agreed revenue requirement on two bases. First, Public Counsel argues that the proposed revenue requirement is excessive given current economic conditions and, if the Commission were to accept the Settlement's revenue

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[241] Coppola, Exh. SC-1CT at 18:1-25:17, 25:18-27:8, 27:9-30:5, 30:8-32:9, 33:3-36:3, 36:7-38:12, 38:14-41:4.

[242] *Id.* at 46:14-49:9, 49:11-50:18, 51:2-53:18, 54:3-57:16, 57:18-60:12, 60:14-63:9, 63:13-68:4, 68:6-72:3, 72:5-74:13, 74:18-79:4, 79:6-84:3, 84:5-86:14, 86:16-89:4.

requirement, the resulting bill impacts would unfairly compound the effects of inflation on customers.[243] Further, Public Counsel argues that growing corporate profit margins are partially responsible for inflation growth and that the Company seeks to earn excessive profits at a time when its customers are struggling.[244] Second, Public Counsel argues that the proposed revenue requirement is inequitable. Referencing the relevant statute for MYRPs, Public Counsel argues that the revenue requirement and resulting rate increase will disproportionately burden low-income and marginalized customers who are already experiencing the impacts of high inflation and other economic challenges.[245] Because of this, Public Counsel argues that the Settlement does not result in equitable rates.[246]

180 Public Counsel's presentation is neither persuasive nor well-founded. The Settling Parties' revenue requirement agreements are results-focused and provide no detail as to which adjustments may have been negotiated by the Settling Parties to reach the resulting agreements. Public Counsel's strategy of recommending adjustments to a results-only revenue requirement makes it difficult, if not impossible, for the Commission to effectuate any of Public Counsel's positions because we cannot determine which, if any, of Public Counsel's positions were already adopted or considered in the negotiations of the Settling Parties when arriving at the agreed revenue requirement. Thus, contrary to Public Counsel's arguments, we find its presentation cannot serve as an appropriate basis to decrement the Settlement's revenue requirement. We decline to break the results-only terms of the Settlement's revenue requirement in order to specify or enumerate any of the adjustments proposed by Public Counsel that might be considered in a fully litigated proceeding or a settlement that enumerated specific adjustments.

181 Avista's initial filing and Public Counsel's adjustments to that filing are record evidence that provide essential context for our evaluation of what balance the Settling Parties have struck between their revenue requirement agreements and the Settlement's other non-revenue terms. However, Avista no longer supports the revenue requirement proposed in its initial filing. That filing does not provide insight into the formulation of the Settling Parties' results-only revenue requirement agreements. Likewise, Public Counsel's arguments against Avista's initial filing provide no insight into what reductions to the

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[243] Dahl, Exh. CJD-1T at 13:9-14:2.

[244] *Id.* at 14:9-19.

[245] RCW 80.28.425 permits the Commission to consider environmental health and greenhouse gas emissions reductions, health and safety concerns, economic development, and equity in determining whether rates are in the public interest.

[246] Dahl, Exh. CJD-1T at 17:10-18:2.

results-only revenue requirement agreements could be justified. In consideration of all the record evidence, we are persuaded that the many terms in the Settlement are fair, just, and reasonable and represent an appropriately negotiated balance between the needs of the Company and the needs of its customers.

182 In addition, we are not merely approving rates that will remain static without oversight of Avista's performance. We assure Public Counsel and Avista's customers that the regulation of Avista going forward will be quite the opposite. For all capital additions during the MYRP, Avista will annually file in these consolidated dockets support for the additions that will be reviewed by the parties and the Commission to determine if any refunds are due customers. We accept and adopt the Settlement's many performance metrics, requiring that Avista file reports on these metrics with the Commission, and place additional assessment measures (pursuant to RCW 80.28.425(7)) for evaluating the MYRP going forward. We address and explain this in greater detail in Section C of this Order. We fully expect, encourage, and welcome Public Counsel's and other ratepayer representatives' engagement in the evaluating investments in the provisional capital review process, evaluating Avista's performance during the MYRP reporting periods, in the Docket U-210590 performance-based ratemaking collaborative, as the regulation of Washington's investor-owned utilities continues to move towards more performance-based regulation as required by statute.

183 Accordingly, for the reasons explained above, we determine that the Settlement's revenue requirement terms should be approved. Based on the decisions we make in this Order for the purposes of authorizing rates that are equitable, fair, just, reasonable, and sufficient, we authorize an increase to Avista's revenue requirement prior to the inclusion of the Residual Tax Customer Credit as set forth in the Settlement of approximately $38.0 million, or 6.9 percent over base rates, for the Company's electric operations in Rate Year 1 of the MYRP, and $12.5 million, or 2.1 percent over base rates, for the Company's electric operations in Rate Year 2 of the MYRP. For the Company's natural gas operations, we authorize an increase of $7.5 million, or 6.6 percent over base rates, in Rate Year 1 of the MYRP, and $1.5 million, or 1.2 percent over base rates in Rate Year 2.

B. SETTLEMENT DETERMINATION

184 Having reviewed the Settlement, its supporting evidence, and all evidence in the record, we conclude that the Settlement is lawful, supported by an appropriate record, and consistent with the public interest, subject to the conditions outlined in this Order.

Accordingly, we determine that approval of the Settlement subject to conditions in concert with the other findings we have made and explained, above, will establish rates, terms, and conditions for Avista's electric and natural gas service to Washington customers that are equitable, fair, just, reasonable, and sufficient. We therefore approve the Settlement subject to the conditions outlined in paragraphs 78, 85, 99, 112, and 146.

185 The Commission's procedural rules require, if we condition our approval of a settlement on terms that are not included in the settlement agreement, as we do here, that we provide the Settling Parties with an opportunity to accept or reject the Commission's conditions.[247] If any of the Settling Parties reject any of the conditions or does not unequivocally and unconditionally accept all of the conditions of our approval of the Settlement as set out in this Order, the Commission will notify the parties that it deems the Settlement to be rejected and will return the adjudication to its status at the time the Commission suspended the procedural schedule for the purpose of considering the settlement subject to compliance with any statutory deadline.[248] Because the statutory deadline in this case is December 21, 2022, the Commission would be unable to complete this proceeding absent the Company's agreed extension of the suspension date.[249] Accordingly, if any of the Settling Parties objects to any of the conditions of our approval of the Settlement in this Order, the Settlement will be deemed denied on the basis that it proposes rates that are not equitable, fair, just, reasonable, or sufficient.

186 We authorize and require Avista to make a compliance filing by December 14, 2022, consistent with the Settlement's terms, our directions and conditions in this Order in these consolidated dockets to recover in prospective rates its revenue deficiency.

C. PERFORMANCE MEASURES PURSUANT TO RCW 80.28.425(7)

187 The Commission must, by law, "determine a set of performance measures that will be used to assess a gas or electrical company operating under a multiyear rate plan."[250] This statutory obligation is placed on the Commission, not any company or party to a GRC. Measures that the Commission might determine appropriate *may* be based on a company's filing, record testimony and evidence, or the proposals made by a company or

[247] WAC 480-07-750(2)(b).

[248] WAC 480-07-750(2)(b)(ii); WAC 480-07-750(2)(c).

[249] WAC 480-07-750(2)(c).

[250] RCW 80.28.425(7) (emphasis added).

other party throughout the proceeding.[251] The Commission's determination, therefore, need not be based upon a company's initial filing, the record testimony and evidence, or the proposals made by a company or party throughout the proceeding. It is not only within the Commission's authority and its discretion to determine a set of performance measures to assess an MYRP, but a requirement of law.

188 As the Settling Parties noted during hearing, the Commission has initiated a proceeding in Docket U-210590 to examine and establish performance metrics, performance incentives and penalties.[252] The Commission's efforts in that docket are proceeding in parallel with the efforts to establish performance measures in this and other general rate case proceedings. Because the Settlement was filed before the Commission issued a Notice of Opportunity to File Written Comment in Docket U-210590 on August 5, 2022, the Settlement's 92 performance metrics do not necessarily reflect the Commission's regulatory goals and desired outcomes or design principles provided in Docket U-210590, which is the Commission's collaborative proceeding concerning performance-based ratemaking.

189 The Settlement proposes 92 performance metrics to be recorded and tracked, but these metrics are not specifically measures appropriate for evaluating Avista's operations under the MYRP. The Settlement's 92 performance metrics also fail to aid the Commission in meeting its statutory obligation because the Settlement lacks detailed information related to how the Commission should use the 92 metrics to evaluate Avista's MYRP or provide all the agreed metric calculations.

190 We therefore determine that certain measures, independent and aside from the 92 metrics included in the Settlement, are necessary for the Commission's future assessment of Avista's operations under the MYRP. We adopt the measures outlined in Table 8, below, regarding operational efficiency, company earnings, affordability, and energy burden. All required reporting should use the same formatting for reporting usage by kilowatt-hours and therms as identified in paragraph 56, above.

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[251] RCW 80.28.425(7).

[252] Section (1) of Engrossed Substitute Senate Bill 5295, Chapter 188, Laws of 2021, directs the Commission initiate a proceeding to address performance based regulation, among other things: "To provide clarity and certainty to stakeholders on the details of performance-based regulation, the utilities and transportation commission is directed to conduct a proceeding to develop a policy statement addressing alternatives to traditional cost of service rate making, including performance measures or goals, targets, performance incentives, and penalty mechanisms."

191

Table 8. MYRP Performance Measures and Outcomes

Topic	Measure/Calculation	Outcome[253]
Operational Efficiency	O&M Total Expense *divided by* Operating Revenue	Assesses how much expense was incurred for every dollar earned. Results at 1.00 or greater might reflect reduced efficiency in controlling O&M spending.
	Operating Revenue *divided by* AMA Total Rate Base and[254] Operating Revenue *divided by* EOP Total Rate Base	Assesses efficient use of rate base to generate revenue. Results less than 1.00 or excessively low results might reflect reduced efficiency in utilizing rate base to generate revenue.
	Current Assets *divided by* Current Liabilities[255]	Assesses liquidity of current assets covering current liabilities. Results less than 1.00 might reflect issues or concerns with liquidity.
Earnings	Net Income *divided by* Operating Revenue	Assesses the amount of net profit gained through revenues earned. Results should be multiplied by 100, to calculate a percentage result, and compared to the authorized ROR.
	Retained Earnings *divided by* Total Equity	Assesses the amount of earnings retained by a company compared to its total equity. Excessively low or high deviations might indicate that the company is paying out more earnings than reinvesting or that the company is retaining more than it needs, respectively. This metric will require baseline information to understand reinvesting and payout patterns.
Affordability[256]	Average Annual Bill Impacts (by Census Tract)	Assesses the average annual residential bill impacts to better understand, over time and by location, affordability of residential rates using the same average energy usage from year to year for better comparability over time.
	Average Annual Bill Impacts (by Zip code)	
Energy Burden[257]	Average Annual Bill *divided by* Average Median Income (by Census Tract)	Assesses the average energy burden of residential customers over time and by location. Results greater than 6 percent indicate energy burden concerns.[258]
	Average Annual Bill *divided by* Average Median Income (by Zip code)	

192 The measures we require Avista to track and report, outlined above, will provide essential and critically important business and customer equity data for the Commission's evaluation of Avista's performance during this MYRP. We also observe that the measures we require, outlined above, will likely continue to be consequential, even beyond this MYRP, for assessing the Company's performance during future MYRPs. Performance-based ratemaking is an iterative process and flexibility is critical. We encourage the parties to these consolidated proceedings to continue to participate in Docket U-210590 through collaboration with the Commission to further assess and define these metrics

193 Likewise, we would find extraordinary benefit from all the historical data related to these measures. At this time, we will not require Avista to search, collect, compile, and provide to the Commission *all* historical data it might have related to these measures. For now, we find that only recent history is necessary for our ability to understand and evaluate Avista's performance at the end of this MYRP. Thus, we require Avista to make a compliance filing within 45 days of this Order to provide the measures and calculations outlined in Table 8, above, for the years 2019-2022 (beginning January 1 and ending December 31 of each year) in order to establish a baseline for our understanding and evaluation. In addition, we require Avista to report the performance measures outlined in Table 8, above, for each year of the MYRP (beginning January 1 and ending December 31 of each year and within 45 days of the end of the reporting period). We will utilize the information gathered through these measures to evaluate the MYRP only, for now, at its conclusion and consider such in our determinations of Avista's next GRC and future MYRPs.

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[253] Outcome descriptions are approximate. Baseline data is required prior to a full understanding of outcomes and results.

[254] Provide results for both calculations but indicate in report whether the Commission authorized the use of AMA or EOP.

[255] "Current" means all current assets that can be converted into cash within one year and all current liabilities with maturities within one year.

[256] These measures are similar to metric 1 in Attachment B to the Settlement. These measures track both by census tract and by zip code. Avista should provide separate results for electric-only customers, gas-only customers, and combined electric and gas customers.

[257] These measures are similar to the metric 2 in Attachment B to the Settlement. These measures track both by census tract and by zip code. Avista should provide separate results for electric-only customers, gas-only customers, and combined electric and gas customers.

[258] *See* Chapter 480-100 WAC.

FINDINGS OF FACT

Having discussed above in detail the evidence received in this proceeding concerning all material matters, and having stated findings and conclusions upon issues in dispute among the Parties and the reasons therefore, the Commission now makes the following summary of those facts, incorporating by reference pertinent portions of the preceding detailed findings:

194 (1) The Commission is an agency of the State of Washington vested by statute with the authority to regulate rates, regulations, practices, accounts, securities, transfers of property and affiliated interests of public service companies, including electric and natural gas companies.

195 (2) Avista is a "public service company," an "electrical company," and "gas company" as those terms are defined in RCW 80.04.010 and used in Title 80 RCW. Avista provides electric and natural gas utility service to customers in Washington.

196 (3) Avista's currently effective rates were determined by the Commission's Final Order in *Wash. Utils. & Transp. Comm'n v. Avista Corp. d/b/a Avista Utils.*, Dockets UE-200900, UG-200901, and UE-200894 *(Consolidated)*, Order 08/05 (Sep. 27, 2021).

197 (4) On January 21, 2022, Avista filed with the Commission revisions to its currently effective Tariffs WN U-28, Electric Service, and WN U-29, Natural Gas Service, proposing a two-year rate plan with increases for its electric and natural gas operations for Rate Year 1 effective December 21, 2022, and for Rate Year 2 effective December 21, 2023.

198 (5) Avista initially requested an increase in its annual electric revenue requirement of approximately $52.9 million (9.6 percent) in Rate Year 1 and of approximately $17.1 million (2.8 percent) in Rate Year 2, and an increase to its annual natural gas revenue requirement of approximately $10.9 million (9.5 percent) in Rate Year 1 and of approximately $2.2 million (1.7 percent) in Rate Year 2.

199 (6) Avista initially requested to partially offset its requested increases with the Residual Tax Customer Credit of approximately $25.5 million for electric and $12.5 million for natural gas. This modified Avista's initial request for an increase

during Rate Year 1 to approximately $40.1 million (7.4 percent) for electric and $4.6 million (2.5 percent) for natural gas.

200 (7) On May 27, 2022, the Commission entered Order 07/01, consolidating Dockets UE-220053 and UG-220054 with Docket UE-210854 pursuant to Staff's unopposed motion to consolidate. Avista had filed in Docket UE-210854 its Electric Service Reliability Reporting Plan pursuant to Washington Administrative Code (WAC) 480-100-393, modifying its previous plan.

201 (8) On June 28, 2022, the Settling Parties filed the Settlement, which proposes to resolve all disputed issues and is attached to this Order as Appendix A. Public Counsel contests certain terms of the Settlement, but either supports or does not oppose the other terms.

202 (9) Subject to the conditions we outline in paragraphs 78, 85, 99, 112, and 146 of this Order, the Settlement proposes equitable, reasonable, fair, just, and well-balanced resolutions, supported by the record, to all disputed issues: overall revenue requirement; cost of capital; cost of service, rate spread, and rate design; the Residual Tax Customer Credit; Colstrip investments, tracker, and Tariff Schedule 99; power costs; the insurance expense balancing account; the escalation study; capital planning; distributional equity analysis; capital projects review; natural gas transition issues; transportation electrification; performance-based ratemaking; low-income issues; the CCA; small business energy efficiency; electric service reliability report plan; depreciation rates and regulatory amortizations; annual filing dates; annual reporting obligations of Docket U-210151; software licensing; decoupling earnings test; and wildfire issues including the wildfire expense balancing account.

203 (10) Avista's currently effective electric and natural gas rates do not provide sufficient revenue to recover the costs of its operations.

204 (11) The performance measures outlined in paragraph 191 and their related reporting requirements are fair, reasonable, consistent with applicable law, in the public interest, and will provide necessary information to allow the Commission to evaluate Avista's operations during the MYRP.

CONCLUSIONS OF LAW

Having discussed above all matters material to this decision, the Commission now makes the following summary conclusions of law, incorporating by reference pertinent portions of the preceding detailed conclusions:

205 (1) The Commission has jurisdiction over the subject matter of, and parties to, this proceeding.

206 (2) Avista is an electric company, a natural gas company, and a public service company subject to Commission jurisdiction.

207 (3) At any hearing involving a proposed change in a tariff schedule the effect of which would be to increase any rate, charge, rental, or toll theretofore charged, the burden of proof to show that such increase is just and reasonable will be upon the public service company. RCW 80.04.130 (4). The Commission's determination of whether the Company has carried its burden is adjudged based on the full evidentiary record.

208 (4) Avista's existing rates for electric and natural gas service are neither equitable, fair, just, reasonable, nor sufficient, and should be adjusted prospectively after the date of this Order.

209 (5) Subject to the conditions in paragraphs 78, 85, 99, 112, and 146, the rates, terms, and conditions in the Settlement are equitable, fair, just, reasonable, and sufficient.

210 (6) The Commission should approve the Settlement subject to the conditions in paragraphs 78, 85, 99, 112, and 146, because it is lawful, supported by an appropriate record, consistent with the public interest in light of all the information available to the Commission. The Settlement, subject to conditions, should be incorporated by reference into the body of this Order, as if set forth in full.

211 (7) The Commission is legally obligated by RCW 80.28.425(7) to determine a set of performance measures that will be used to assess Avista's operations under the MYRP.

212 (8) The Commission's determination of a set of performance measures need not be based upon a company's initial filing, the record testimony and evidence, or the proposals made by a company or party throughout the proceeding.[259]

213 (9) The Commission should adopt the performance measures outlined in paragraph 191 and Avista should be authorized and required to make necessary and sufficient future compliance filings in accordance with the directions and conditions of this Order.

214 (10) Avista should be authorized and required to make a compliance filing within 45 days of this Order to provide the measures and calculations outlined in paragraph 191 for the years 2019-2022 (beginning January 1 and ending December 31 of each year).

215 (11) Avista should be authorized and required to make an annual compliance filing to report the performance measures outlined paragraph 191 for each year of the MYRP (beginning January 1 and ending December 31 of each year and within 45 days of the end of the reporting period).

216 (12) Avista should be authorized and required to make a compliance filing by December 14, 2022, and make future compliance filings consistent with the directions and conditions in this Order in these consolidated dockets to recover in prospective rates its revenue deficiency prior to the inclusion of the Residual Tax Customer Credit of approximately $38.0 million for its electric operations in Rate Year 1, $12.5 million for its electric operations in Rate Year 2, $7.5 million for its natural gas operations in Rate Year 1, and $1.5 million for its natural gas operations in Rate Year 2.

217 (13) The Commission should authorize and require Avista to replace the existing decoupling earnings test with the earnings test provided in RCW 80.28.425(6), including accruing ROR on the balance of the decoupling deferral, and deferring any earnings greater than 0.5 percent above its authorized ROR, consistent with the Settlement and RCW 80.28.425(6).

218 (14) The Commission should authorize and require all Settling Parties to separately notify the Commission by December 19, 2022, by a letter to the Commission

[259] *See* RCW 80.28.425(7).

Secretary filed in these consolidated dockets whether each accepts the conditions of approval set by this Order on the settlement stipulation.

219 (15) The Commission Secretary should be authorized to accept by letter, with copies to all Parties to this proceeding, filings that comply with the requirements of this Order.

220 (16) The Commission should retain jurisdiction over the subject matter and the Parties to effectuate the terms of this Order.

ORDER

THE COMMISSION:

221 (1) Rejects the proposed tariff revisions Avista Corporation d/b/a Avista Utilities filed in these dockets on January 21, 2022, and suspended by prior Commission order.

222 (2) Determines the settlement stipulation is lawful, supported by an appropriate record, and consistent with the public interest and therefore approves it subject to the conditions set by the Commission in paragraphs 78, 85, 99, 112, and 146.

223 (3) Authorizes and requires replacing the existing decoupling earnings test with the earnings test provided in RCW 80.28.425(6), including accruing a rate of return on the balance of the decoupling deferral, and deferring any earnings greater than 0.5 percent above its authorized rate of return, consistent with the settlement stipulation and RCW 80.28.425(6).

224 (4) Authorizes and requires all Settling Parties to separately notify the Commission by December 19, 2022, by a letter to the Commission Secretary filed in these consolidated proceedings whether each accepts the conditions of approval set by this Order on the settlement stipulation.

225 (5) Adopts the performance measures outlined in paragraph 191.

226 (6) Authorizes and requires Avista Corporation d/b/a Avista Utilities to make all compliance filings determined by this Order in these consolidated dockets, including all tariff sheets that are necessary and sufficient to effectuate the terms of this Order as well as including the compliance filing within 45 days of this

Order to provide the measures and calculations outlined in paragraph 191 for the years 2019-2022 (beginning January 1 and ending December 31 of each year).

227 (7) Authorizes the Commission Secretary to accept by letter, with copies to all Parties to this proceeding, filings that comply with the requirements of this Order.

228 (8) Retains jurisdiction to effectuate the terms of this Order.

DATED at Lacey, Washington, and effective December 12, 2022.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DAVID W. DANNER, Chairman

ANN E. RENDAHL, Commissioner

MILT DOUMIT, Commissioner

APPENDIX A

MULTIPARTY SETTLEMENT STIPULATION

Who Will Pay for Legacy Utility Costs?

Lucas W. Davis, Catherine Hausman

Abstract: The growing "electrify everything" movement aims to reduce carbon dioxide emissions by transitioning households and firms away from natural gas toward electricity. This paper considers what this transition means for the customers who are left behind. Using historical evidence from growing and shrinking US natural gas utilities, we show that utilities add pipelines but rarely remove them, even when the customer base from which to recover costs is shrinking. Correspondingly, we find that utility revenues decrease less than one for one when a customer base is shrinking, consistent with higher bills for remaining customers. We then use our empirical estimates to predict how customer bills might increase in the future for different levels of building electrification. We highlight the equity implications of our results and conclude by discussing alternative utility financing options such as recouping fixed costs through taxes rather than prices.

JEL Codes: L95, L97, Q40, Q48, R11

Keywords: natural monopoly, stranded costs, sunk costs, natural gas, energy utilities, building electrification, inequality, energy transition, energy justice

NATURAL MONOPOLIES TYPICALLY RECOVER FIXED COSTS by spreading fees out over their customer base across time, whether through per-unit fees, per-customer fees, or a combination. In the United States, this is true of privately held utilities, municipally run utilities, and utilities run by other governmental agencies (e.g., federal) across a

Lucas W. Davis is at the University of California, Berkeley (lwdavis@berkeley.edu). Catherine Hausman is at the University of Michigan (chausman@umich.edu). We have not received any financial compensation for this project, nor do we have any financial relationships that relate to this research. We thank Marshall Blundell for excellent assistance with the utility service territory data. We are thankful to Severin Borenstein, Eva Lyubich, Justin Kirkpatrick, William Wheeler, and seminar and conference participants at the University of Illinois, Midwest Energy Fest, Western Economic Association, University of California Berkeley, University of Hawaii, Environmental Protection Agency, Resources for the Future, and Indiana University for helpful comments.
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broad range of goods: electricity, natural gas, water, wastewater services, garbage collection, and more. Seldom discussed in the literature is that in times of a shrinking customer base, this approach can lead to difficulties recovering fixed costs; either prices must rise, or costs (such as maintenance of infrastructure) must be cut.

This dynamic is important for understanding the effects of environmental policies that target utilities. In particular, this issue is currently coming to a head with US natural gas utilities due to a growing number of policies aimed at transitioning customers away from natural gas toward electricity.[1] Building electrification has been called "a linchpin solution for decarbonization" (National Academies of Sciences, Engineering, and Medicine 2021), and recent proposals for a transition to carbon neutrality rely on scenarios in which the vast majority of the building stock is transitioned to all electric in a few decades (Larson et al. 2020; National Academies of Sciences, Engineering, and Medicine 2021; Williams et al. 2021).

This paper considers what such a transition would look like for the natural gas customers who are left behind. The current push for building electrification is still in its early stages, so it is too soon for an empirical analysis of how utility behavior responds to this policy push. Instead, we use historical evidence from growing and shrinking utilities. Although mostly driven by reasons other than building electrification, this evidence is nonetheless a valuable opportunity to learn how utilities change their operations and finances when large numbers of customers enter or exit.

First, we demonstrate that both customer base growth and customer base loss are commonplace among US natural gas distribution utilities during our sample period of 1997–2019. We observe, for example, 320 utilities that experienced five or more consecutive years of customer growth, and 250 utilities that experienced five or more consecutive years of customer base decline. Although the total number of natural gas customers in the United States has increased 25% over this time period, many specific regions have lost population, and we show that customer base declines are associated with net migration patterns. For example, Alabama Gas Corp—a large utility serving Birmingham and much of central Alabama—has consistently experienced a shrinking customer base at the same time the city of Birmingham has lost population.

Second, we examine what these customer base changes mean for utility operations. For most natural gas distribution utilities, the pipeline infrastructure is the single largest asset and the single largest fixed cost. We compile annual data on the total number of pipeline miles operated by each utility and test how this responds to changes in the customer base. We find that when utilities are growing, they add pipelines. A 10% increase

1. A number of policies have been introduced to encourage electrification, including municipal bans on natural gas in new construction, electric preferred building codes, and subsidies for heat pumps. These policies are in part motivated by the ongoing decline in emissions from the electricity sector (Holland et al. 2020), which means that transitioning households and firms from natural gas to electricity could significantly reduce environmental damages.

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in the number of residential customers leads to a 4% increase in the length of the distribution network. However, when utilities are shrinking, they do not remove pipelines. A 10% decrease in the number of residential customers has a precisely estimated 0% effect on the length of the distribution network. Utilities add pipelines but rarely remove them, even when the customer base from which to recover costs is shrinking.[2]

Third, we test for changes in utility finances. As with pipelines, we find that utility revenues respond asymmetrically to changes in the customer base. New customers lead to one-to-one revenue increases, with a 10% increase in residential customers increasing revenues by 10%. In contrast, customer losses lead to a less than one-to-one decrease in revenue, with a 10% decrease in residential customers decreasing revenues by only about 5%. This pattern implies that remaining customers make up about half of the lost revenue through increased prices. The remaining half may represent cost savings, or it may represent losses to shareholders, an issue we discuss. While previous white papers have pointed to the possibility of bill impacts, we provide the first empirical evidence on the magnitude of these effects using comprehensive data and a quasi-experimental strategy.

These increased bills for remaining customers have significant equity implications. We show that many shrinking utilities in our data serve cities with high rates of poverty and with large African American populations in parts of the Rust Belt and Appalachia and in some rural areas. Looking forward, the current push for building electrification is likely to lead to a very different pattern of customer exit. Nonetheless, in both cases there is a set of remaining customers left facing higher bills, and our results underscore the potential for these impacts to be highly uneven across income levels and racial groups.

We use our empirical estimates to predict how customer bills might increase in the future for different levels of building electrification, absent regulatory changes. We find that bill impacts are modest as small numbers of households transition away from natural gas: for a 20% reduction in residential gas customers, we calculate bill increases of around $40 per year for remaining customers. However, impacts increase nonlinearly as an increasing number of households leave natural gas. For a 40% reduction in customers, we calculate bill increases of $115 per year.

To understand how customer exit could lead to these outcomes, we next examine ancillary data on categories of expenditures for a sample of large US natural gas utilities. We show that a substantial portion of expenditures are fixed costs that, at least in the short run, are unlikely to change as customers leave natural gas service. This includes capital costs (25%), maintenance and operations (10%), and administrative expenses such as pension payments (10%).

Finally, we discuss various alternatives for financing legacy costs. While the norm has been to pay for these costs through monthly bills, we explore, for example, the

2. A similar asymmetry arises with "durable housing" and the idea that it is relatively easy to build more homes as demand increases but that those homes remain even after demand decreases (Glaeser and Gyourko 2005).

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possibility of collecting hook-up and exit fees. We also raise the possibility of shifting costs to utility shareholders, across utilities, or to the general tax base. With each alternative we briefly discuss the likely impacts for remaining customers as well as the broader implications for efficiency and equity.

Several features of the natural gas market make it a particularly good setting for such an analysis. First, natural gas distribution is a quintessential natural monopoly, making it an ideal setting for studying what happens to legacy utility costs during market transitions. Second, even relative to other utilities like electricity distribution companies, both the physical pipeline infrastructure and financial data such as revenue are particularly well observed, a product of the highly regulated nature of the industry. We note that the industry is regulated in part precisely because it is a natural monopoly but also because proper maintenance of the distribution network is important for safety and environmental reasons—inadequate maintenance can lead to pipeline explosions and to methane leaks. Finally, natural gas has historically provided important services (heating, cooking, and water heating) to a large portion of US households and firms. As of 2019, natural gas was used in the United States by 70 million households and 6 million commercial establishments, and sales in these two sectors totaled $70 billion.

Our paper contributes to a broader literature on infrastructure investment, fixed cost recovery, and the optimal regulation of natural monopolies. This literature has emphasized a number of regulatory challenges in this environment, including how to create incentive-compatible regulations that allow for cost-minimization without sacrificing infrastructure quality or other goals (Bonbright 1941; Averch and Johnson 1962; Viscusi et al. 2005; McRae 2015). We consider a previously understudied dynamic issue: customer base loss and the recovery of legacy infrastructure costs. While we focus on natural gas in our empirical example, the mechanisms we document are likely to apply to other natural monopolies that recover fixed costs by spreading fees across customers, including water utilities, urban transit, the transition from landlines to wireless, the impact of rooftop solar on electricity distribution, and so forth.[3]

Our paper also contributes to a broader literature on natural gas utilities. Natural gas combustion currently makes up around one-third of total US fossil-fuel related CO_2 emissions (Environmental Protection Agency 2021), and papers exploring how the natural gas sector contributes to climate change include Newell and Raimi (2013), Hausman and Kellogg (2015), Mason et al. (2015), and Marks (2022). Focusing on distribution utilities, Hausman and Muehlenbachs (2019) look at regulatory impacts on the incentives for environmental and safety protection. Natural gas rate design has been explored

3. Cost recovery difficulties associated with customer base changes have been pointed out for water utilities (Beecher et al. 1990; Beecher et al. 1992; Faust et al. 2016; Beecher 2020; Swain et al. 2020); and Galster (2017) makes this connection for population loss and the provision of city services. Gabel and Burns (2012) similarly discuss cost recovery issues in the transition from landlines to wireless and voice-over internet.

by Knittel (2003), Davis and Muehlegger (2010), Borenstein and Davis (2012), Hausman (2019), and Auffhammer and Rubin (2021). Perhaps most closely related is the work on bypass, which examines industrial customer retention (Laffont and Tirole 1990), for instance, at the time of deregulation of wholesale natural gas prices.[4]

Our paper speaks directly to policy issues around building electrification. Davis (2021) empirically examines the customer decision making around home heating technologies, calculating willingness to pay to avoid an all-electric transition. A number of white papers have examined costs and benefits of building electrification in California (Bilich et al. 2019; Greenlining Institute 2019; Gridworks 2019; Mahone et al. 2019; Aas et al. 2020). But we are not aware of any statistical analysis applying to the broader United States.

Our work also speaks to questions of the incidence of environmental policies, an issue explored at depth in Bento (2013) and Fullerton and Muehlegger (2019). In particular, our analysis is related to a recent and growing literature on equity issues in energy transitions. This is crucial for analyzing climate policies, including how to best structure them and who will be the winners and losers of the policies. For instance, Van der Ploeg and Rezai (2020) discuss how an unanticipated transition could result in billions of dollars in stranded assets in fossil fuel industries.

Most closely related in this vein is the work examining how rooftop solar can push fixed cost recovery onto low-income customers (Burger 2019; Borenstein et al. 2021)—this is a function of high mark-ups in high-solar penetration areas like California. In contrast, the mechanism in our paper is a function of customer losses, which applies even when fixed costs are recovered through fixed fees. Thus the standard rate reforms that are frequently suggested for rooftop solar would still lead to fixed cost recovery issues and equity challenges in our setting. A similar mechanism could apply to the electricity sector in future scenarios with so-called "grid defection," in which the installation of storage along with the rooftop solar allows a customer to disconnect from an electric utility altogether (Gorman et al. 2020). More broadly, the equity issues we document may interact with preexisting equity issues in residential energy markets (Reames 2016; Carley and Konisky 2020; Lyubich 2020).

Finally, our results on economic and racial inequities also contribute to the literature on rural depopulation (Johnson and Lichter 2019) and on shrinking cities (Beauregard 2009), where a combination of economic forces and racial antagonism has been identified

4. Relatedly, studies of electricity market deregulation have emphasized the crucial role played by stranded costs, i.e., utility investments which would be unrecoverable in a deregulated market. White (1996, 242) argues that "this stranded cost problem is by far the most controversial aspect of regulatory reform in the electric power industry." Borenstein and Bushnell (2015, 443) argue that US electricity market deregulation was motivated largely by "an opportunity to shift responsibility for paying the sunk costs of what were considered uneconomic stranded assets." Although the catalyst is quite different (deregulation vs. energy transition), the economics of these fixed, mostly sunk costs is similar to the legacy costs that would be borne in a transition away from natural gas.

(Boustan 2010; Galster 2017). We empirically show that these broad migration patterns in the United States can directly impact the ability of utilities to provide the basic services that households require. While we focus on natural gas, similar mechanisms are expected in water and other utility services.

1. DATA

1.1. Data Sources

Our empirical analysis takes advantage of the unusually rich data available for the US natural gas distribution sector. The highly regulated nature of this sector means that detailed information is available from multiple government agencies, including the Department of Energy and the Department of Transportation. We are able to observe key aspects relating to both physical infrastructure and to the utilities' financials, including sales, revenues, and prices.

Our core data set is an annual panel describing essentially the universe of US natural gas distribution utilities for the years 1997–2019. Most of this information comes from an annual census of natural gas distribution utilities conducted by the US Department of Energy's Energy Information Administration (EIA).

This EIA-176 data set reports customer count, volume sold, and revenue collected by end-user sector (e.g., residential vs. commercial).[5] These data also report the utility's ownership structure (investor-owned, municipal, etc.).[6] For utilities that operate across multiple states, there is a separate entry for each state's operations. From EIA, we also observe average citygate prices at the state level, that is the average price (in dollars per thousand cubic feet [mcf]) paid by utilities in that state when purchasing natural gas. We deflate all revenue and prices by the annual consumer price index from the Federal Reserve Economic Data (FRED), reporting all dollar amounts in 2019 dollars.

One of our primary outcome variables is "net revenue," which we calculate by taking total utility revenue and subtracting off the portion of revenue that is collected to pay for purchasing natural gas. These additional revenues are collected to pay for pipeline investments, maintenance and operations, administrative salaries, and other costs. Whereas natural gas purchases can be easily adjusted upward and downward in response to changes in customer counts and fluctuating consumption levels, this net revenue stream is how the utility pays for fixed costs. Focusing on net revenue means that throughout the analysis we

5. Our analysis throughout ignores industrial customers, as they make up a very small fraction of total customers and because there is too little change in the number of industrial customers to support an empirical analysis.

6. We simplify the designations somewhat by combining some categories. For instance, we combine "investor-owned utilities" and "privately owned utilities," regardless of whether they are, for instance, publicly traded. We also group into the "municipal" category some rural cooperatives and a few other kinds of government-run agencies such as county-run utilities. See the appendix for details.

are able to largely ignore variation in natural gas commodity prices, weather, macroeconomic shocks, and other factors that lead to short-run fluctuations in utility total revenue.

Our other key data source is an annual utility-level census (1997–2019) from the Pipeline and Hazardous Materials Safety Administration (PHMSA) at the Department of Transportation. Natural gas distribution utilities are required under federal law to submit annual reports to PHMSA. This information is used by PHMSA and other government agencies to enforce pipeline safety regulations, track and investigate incidents, and plan inspections. Utilities are required to submit separate reports for each state in which they operate.

The primary variable we use from this data set is the total "distribution main mileage" per utility per year. Distribution mains are the pipelines that carry natural gas under city streets. To merge the EIA and PHMSA data, we use a fuzzy string match on utility names and an exact match on the state within which the utility operates. We are able to match 83% of the EIA observations to PHMSA data (representing 87% of residential customers). See the appendix (available online) for details.

Finally, we collect weather data from the National Oceanic and Atmospheric Administration (NOAA), specifically annual heating and cooling degree days at the state level.

1.2. Summary Statistics

Table 1 provides summary statistics. Our sample consists of an unbalanced panel with around 1,300 utilities per year. Of these, around one-quarter are investor-owned utilities and three-quarters municipal utilities. The summary statistics reveal the tremendous variation in utility size, including substantial skew. The mean number of residential customers is 41,000, but the median number is 1,000. This skewness reflects the fact that there are many small municipally operated natural gas utilities, as well as a much smaller number of large investor-owned utilities like Southern California Gas Company, which serves nearly six million households.

Our main specification limits the sample in a few ways to reduce measurement error. First, we focus on utilities for which at least 90% of residential customers are "bundled," rather than "retail choice." Fewer than 2% of utilities are dropped because of this exclusion. Second, we assign new utility identification numbers when we observe an annual residential customer change of more than 20 log points or a commercial change of more than 50 log points. These large changes likely indicate service territory adjustments, mergers, or acquisitions rather than true customer growth or loss. In specifications using differences, this assignment of a new identification number drops the year with the large change but keeps subsequent years. Third, we drop a small number of extreme outliers for the other variables, which we attribute to clerical errors and other reporting mistakes. See the appendix for details.

Finally, in our regression analysis we focus on utility-years that are part of at least a two-year period of sustained growth or loss. That is, we drop observations where a utility grows in one year, shrinks in the next, and so forth. We do this for two reasons.

Table 1. Summary Statistics

	N	Mean	Median	SD	Min	Max
Residential:						
Customers, '000s	29,392	41.31	1.07	229.60	.00	5,607.69
Bundled customers, proportion	29,392	1.00	1.00	.01	.90	1.00
Dummy, customer base growing	27,671	.51	1.00	.50	.00	1.00
Sales, bcf	29,388	2.91	.06	14.58	.00	277.72
Average price, $/mcf	29,382	13.56	12.95	5.41	.58	445.40
Revenue, '000,000s	28,977	27.54	.72	129.95	.00	3,515.88
Net revenue, '000,000s	28,644	17.44	.37	86.02	.00	2,101.42
Per customer, '000s	28,630	.37	.35	.19	.00	3.40
Per mcf	28,641	6.99	6.27	4.02	.00	52.48
Citygate price, $/mcf	29,392	6.77	6.13	2.53	2.03	36.07
Miles of pipeline, '000s	24,452	.77	.06	3.07	.00	51.25
= 1 if investor-owned utility	29,392	.24	.00	.43	.00	1.00
= 1 if municipal utility	29,392	.76	1.00	.43	.00	1.00

Note. This table provides summary statistics for our main estimation sample, an unbalanced panel covering the period 1997–2019, with approximately 1,300 natural gas distribution utilities per year. The sample excludes a small number of utilities for which more than 10% of customers buy natural gas from a retail choice provider. There are fewer observations for the "Dummy, customer base growing" variable because it cannot be calculated for the first year a utility appears in the sample. There are fewer observations for the "Miles of pipeline" variable because of imperfect matches across data sources. Commercial customer summary statistics are in the appendix. bcf = billion cubic feet; mcf = thousand cubic feet.

First, for our thought experiment of a utility losing customers because of electrification, we are interested in sustained patterns of loss. Second, if the miles and customer counts are measured at different times in a year, the year-on-year changes may not match up in time. This would be most concerning if a utility grows in one part of a year but shrinks in another part of the year. In the appendix, we show results relaxing this and each of the other sample selection criteria.

2. GROWING AND SHRINKING UTILITIES

We are interested in how utility operations and infrastructure investments respond to changes in the size of the customer base. Of course, historical evidence of these patterns is only valuable to the degree that utilities actually experience meaningful changes in the customer base. In this section, we describe the patterns of customer base growth and loss over the past two decades. Absent from most policy discussions about the energy transition is ex post evidence on how utilities have historically managed customer base loss. We show that such experiences are commonplace, and we argue that important lessons can be drawn from these utilities.

2.1. Preliminary Graphical Evidence

Figure 1 plots residential customer counts over time for a random 4% of utilities. We normalize each utility's count to 1 at the beginning of the sample. As illustrated by the figure, there are widely differing experiences across utilities. Even though the US population is growing, a substantial portion of utilities lose customers over this 22-year period. There are many utilities that grow by 20% or more, but also many utilities that shrink by 20% or more.

The figure also reveals considerable persistence in both growth and loss. Recall that table 1 shows that about half of all utility-year observations involve customer base loss; figure 1 illustrates that this is not due to one-year "blips." For example, we observe around 320 utilities that experience five or more consecutive years of customer base growth but also around 250 utilities that experience five or more consecutive years of customer base loss.

2.2. Compositional Patterns

To better understand the patterns driving these periods of growth and loss, we summarize in table 2 the "proportion growing" variable across different utility types. Investor-owned

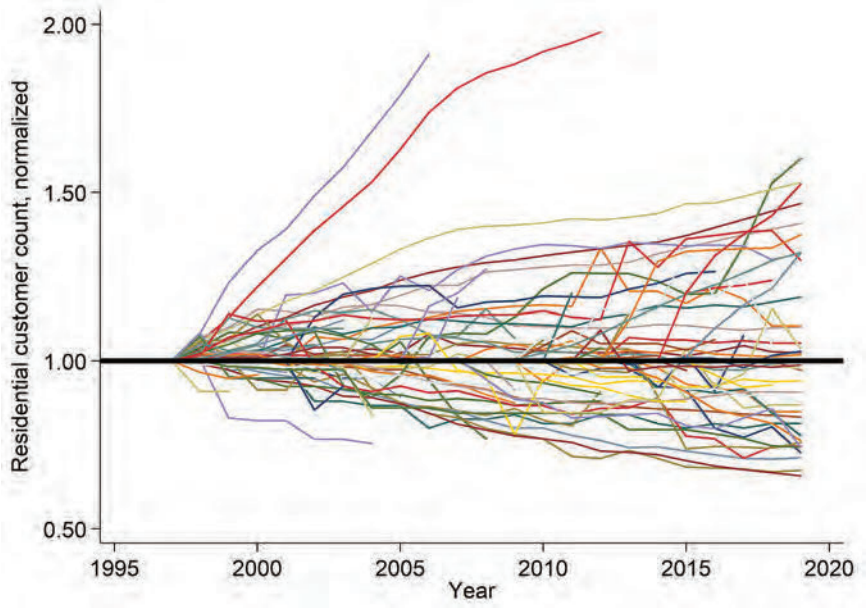

Figure 1. We observe growing and shrinking utilities. This figure shows residential customer counts for a random 4% sample of utilities, normalized to 1 in their first year. Large changes have been assigned a new utility ID to account for the possibility of mergers and acquisitions. The graph has been zoomed in to a maximum of 2.0 on the *y*-axis; the two utilities with the largest growth continued on an upward trend (not shown).

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Table 2. What Types of Utilities Are Growing?

	N	Proportion with Residential Growth
All utility-years	24,543	.52
By ownership type:		
Investor-owned utilities	6,094	.71
Municipally owned utilities	18,449	.46
By number of residential customers in first year:		
1 million or more	156	.92
100,000–1 million	1,811	.82
10,000–100,000	2,695	.75
1,000–10,000	8,710	.56
100–1,000	10,678	.39
1–100	493	.31
By time period:		
1997–2007	10,921	.54
2008–19	13,622	.51
By geographic region:		
New England (CT, MA, ME, NH, RI, VT)	504	.89
Pacific (CA, OR, WA)	465	.83
Mountain (AZ, CO, ID, MT, NM, NV, UT, WY)	1,230	.74
Middle Atlantic (NJ, NY, PA)	642	.70
East North Central (IL, IN, MI, OH, WI)	3,134	.55
West North Central (IA, KS, MN, MO, ND, NE, SD)	4,541	.54
East South Central (AL, KY, MS, TN)	5,483	.53
South Atlantic (DC, DE, FL, GA, MD, NC, SC, VA, WV)	3,640	.48
West South Central (AR, LA, OK, TX)	4,904	.37

Note. This table describes our main estimation sample, classifying observations along several different dimensions. For each subset of the sample, the table reports the total number of utility-year observations as well as the proportion of utility-year observations for which the residential customer base grew.

utilities are more likely to be growing than are municipal utilities, but even for investor-owned utilities more than one-quarter of utility-year observations are not growing. The high loss portion in municipally owned utilities is likely related to rural depopulation in the United States, discussed further below.

In addition, we find that medium and large utilities tend to be growing, while small utilities tend to be shrinking. For these statistics we measure the number of residential customers during the first year the utility appears in our sample. The proportion of all utility-year observations growing is monotonic across size categories, ranging from 92% for very large utilities to 31% for very small utilities.

Finally, we see a clear geographic pattern. The regions with the most customer growth include New England and the West ("Pacific" in the census region nomenclature), with over 80% growth in each. The regions with the most customer loss include the South Atlantic and the Gulf Coast/Oklahoma/Texas area ("West South Central" in the census region nomenclature). These geographic differences are difficult to interpret by themselves, because different regions have different utility sizes and different utility ownership patterns, for historical reasons. As such, we next analyze these regional differences separately for investor-owned utilities and municipal utilities.

2.3. Additional Geographic Evidence

In figure 2, we provide two maps aimed at better understanding the geographic pattern. We plot, at the state level, the proportion of utility-year observations with residential customer growth for investor-owned utilities (fig. 2*A*) versus municipal utilities (fig. 2*B*). The high proportion of growth in New England reflects that the region is served only by investor-owned utilities and not by any municipal utilities. In contrast, the high proportion of growth in the Pacific region is seen in both the investor-owned and municipal utility maps.

These maps suggest that customer base changes are somewhat correlated with regional population changes. Western states such as New Mexico, Washington, Utah, Nevada, and Idaho experienced growth at all investor-owned utilities in all years. Notably, all of these states also experienced substantial population growth over the 1997–2019 time period, with Nevada, Arizona, and Utah experiencing the largest population growth rates in the country. In contrast, West Virginia lost population over this time period, and southern states like Mississippi and Louisiana had fairly slow population growth rates compared to much of the country.

To corroborate this pattern, we merged population estimates from the US Census Bureau with the geographic boundaries of US natural gas distribution utilities as of 2017.[7] This exercise is imperfect because it fails to capture changes in service territory boundaries over time and because overlapping service territory boundaries and other issues introduce measurement error. Nevertheless, we are able to show using these merged data that population changes are highly correlated with changes in residential customer counts, particularly for larger utilities. Although there are many factors driving residential customer counts, it seems clear that population changes are the primary driver. See table A3 (tables A1–A11 are available online).

2.4. Anecdotal Evidence from Selected Utilities

The correlation between customer count changes and population changes matches anecdotes from several utilities. In a rate case filing for DTE—a large utility serving Detroit and southeast Michigan—one analyst testified that "the poor local economic

7. Details are in the appendix.

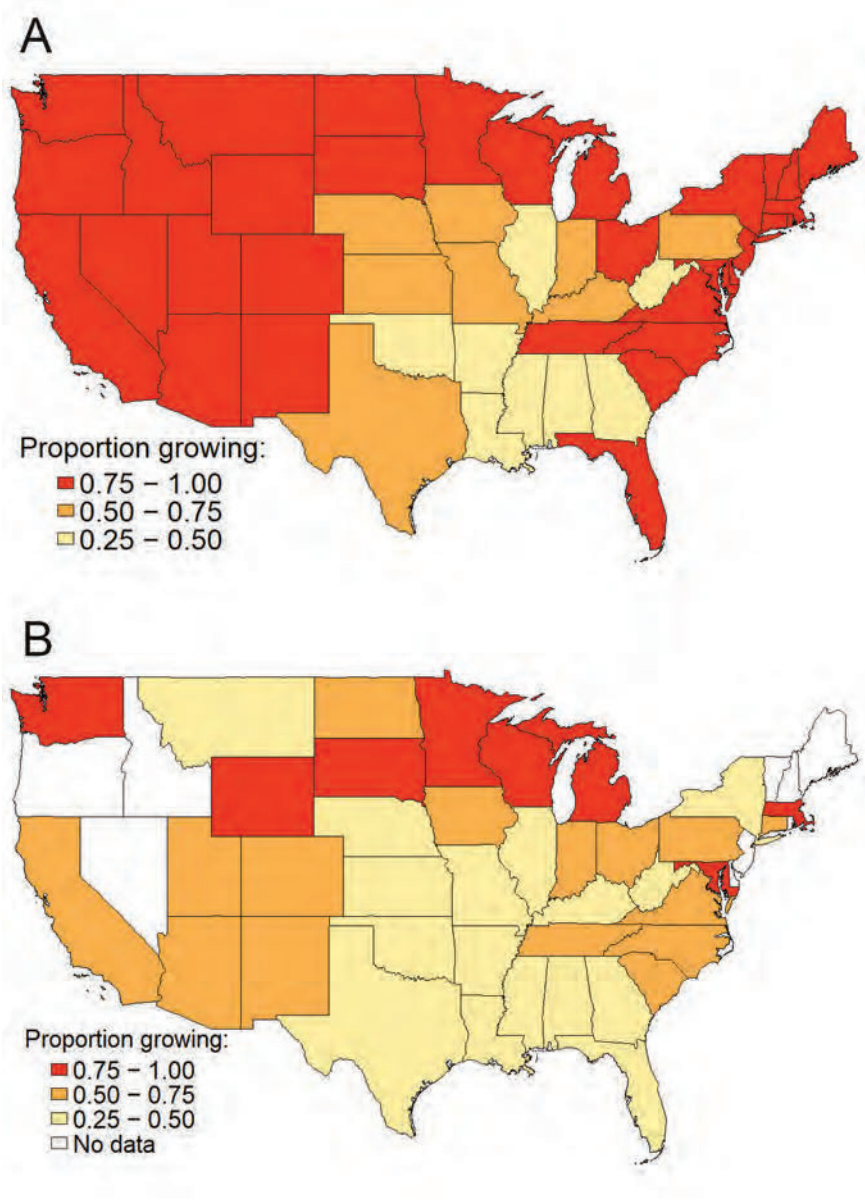

Figure 2. Regional patterns in residential customer base changes. These maps show by state the proportion of utility-year observations with residential customer growth separately for investor-owned (*A*) and municipally owned (*B*) utilities. White states in panel *B* do not have any municipal utilities.

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conditions in DTE Gas's service territory as well as declining population exacerbate the effect of declining sales in increasing the downside risk that DTE Gas may not be able to fully recover its fixed costs."[8] National Fuel, serving upstate New York and parts of Pennsylvania (such as Pittsburgh) similarly argued that "it grapples with a declining population and a weak economy in its service territory" (Robinson 2001). A rate case for Centerpoint Arkla (Arkansas) discusses related challenges, with a growing number of pipeline miles but a decreasing number of customers: "declining revenues and increasing costs make it difficult, if not impossible, for the Company to recover its cost of service."[9]

An especially compelling case study is that of Philadelphia Gas Works, the largest municipally owned gas distribution utility in the country. A white paper details the financial struggles, noting: "The challenging demographics of PGW's customer base are a byproduct of Philadelphia's shrinking population and high concentration of poverty. The City has lost nearly 30% of its population over the past half-century." The report goes on to note implications for prices that we discuss further below: "with a declining customer base characterized by a high concentration of poverty, the need for additional price increases to cover fixed expenses seems inevitable" (Economy League of Greater Philadelphia 2008).

Municipal utilities tend to serve rural populations, and as such their customer base loss (with the exception of some urban utilities like Philadelphia Gas Works) may reflect rural depopulation. For this utility type, Cairo Public Utility Co. of Illinois provides a clear case study. A series of news articles from 2017 summarizes the financial challenges facing this rural utility and the high bills facing its customers. As one of the articles notes, "[utility administrators] said that part of the issue with Cairo Public Utility Co. is that they are managing a system that was originally built for 20,000 people, and today Cairo is home to only about 2,500" (Smith 2017).

In contrast to these anecdotes from rural areas, the Rust Belt, and parts of the Southeast, utilities in the Southwest and the West note a very different experience. For instance, the annual report for Southwest Gas (serving Arizona, Nevada, and California), notes, "Southwest Gas remains among the top utilities for customer growth with 26,000 net new customer additions in 2015. This is due in part to a growing economic recovery across Southwest Gas service territories," going on to describe how projected population growth rates in its major metro areas are much higher than for the United States as a whole.[10]

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8. LARA Filing U-17999-0002, December 18, 2015, DTE Energy Company, Testimony, case no. U-17999. https://mi-psc.force.com/s/filing/a00t0000005pl9SAAQ/u179990002 (accessed May 18, 2021).

9. Docket no. 04-121-U, filed December 3, 2004. http://www.apscservices.info/pdf/04/04-121-u_35_1.pdf (accessed February 2, 2021).

10. Southwest Gas 2015 Annual Report. https://www.swgas.com/www/flipbooks/Swgas_Annual_Report_2015/mobile/index.html#p=2 (accessed May 18, 2021).

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Similarly, Questar Gas's annual report notes, "The population of the Company's service area in Utah continues to grow faster than the national average."[11]

Overall, the main takeaway is that many US natural gas utilities have faced years of customer base loss. This is especially true of small utilities and of municipal utilities, and a major factor appears to be population changes. The experience of these utilities might be informative as policies seek to transition building energy use from natural gas to electricity. We next turn to an empirical examination of utility operations and finances.

3. RESULTS

3.1. Pipelines

We begin by examining the relationship between the physical pipeline network and the number of customers. Figure 3 plots the relationship between the log change in pipeline miles and the log change in residential customer counts. The figure also shows a histogram of log residential customer count changes—matching the summary statistics in table 2, the histogram shows that roughly half of residential customer changes are positive and half are negative.[12]

A clear positive relationship emerges in figure 3. As utilities grow, they add pipelines. However, a clear asymmetry is also visible. In addition to the scatterplot (with markers sized by initial utility size), we overlay a lowess smoother. Importantly, this lowess smoother does not impose any asymmetry—but one emerges naturally. With growth in the residential count, that is, on the right-hand side of the plot, there is an upward-sloping, nearly linear fit between the log growth in miles and the log growth in residential customers. With loss in the customer count, that is, on the left-hand side of the plot, there is essentially no change in the log mile count. There is a slight upward tick on the far left side of the plot, but there are almost no observations in that region, as shown in the histogram along the bottom. In contrast, there is a substantial mass of observations closer to the origin, that is, at around zero to five log points of loss. Typically when a utility loses a small percentage of customers, it experiences no change in its pipeline miles.

We next formalize this intuition with two sets of regressions. First, we regress the log change in pipeline miles on the log change in residential and commercial customer counts. The regression takes the form:

$$\Delta \ln M_{i,t} = \alpha + \beta \Delta \ln R_{i,t} + \gamma \Delta \ln C_{i,t} + \varepsilon_{i,t}, \quad (1)$$

11. Questar Gas 1999 Annual Report. https://www.sec.gov/Archives/edgar/data/68589/0000068589-99-000002.txt (accessed May 18, 2021).

12. In the appendix, we show a histogram for the change in log miles. Five percent of observations involve a reduction in log miles from one year to the next; these observations have a median log change of −0.006.

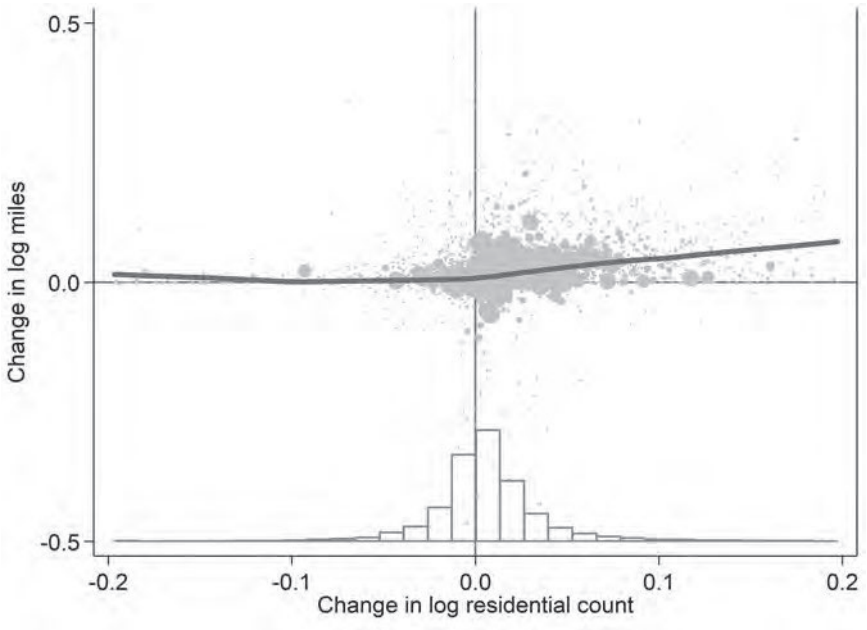

Figure 3. The asymmetric relationship between pipelines and customers. The thick dark line shows a lowess fit. The lowess has been fit to the full estimation sample, but the scatterplot is zoomed in to [−0.5, 0.5] on the *y*-axis to make the lowess slope more visible. A histogram for changes in residential counts is included at the bottom of the figure. Color version available as an online enhancement.

where $M_{i,t}$ is the miles of pipeline mains at utility i in year t, $R_{i,t}$ is the count of residential customers, and $C_{i,t}$ is the count of commercial customers. Standard errors are clustered by utility to account for serial correlation.

We use logs to ease comparisons across large and small utilities. We use differencing because we are interested in what happens as utilities grow or shrink, rather than in cross-sectional differences between large and small utilities. One could instead use fixed effects, which we show in the appendix. In our baseline specification, we do not use any controls, as we do not expect there to be factors that require a utility to grow its pipeline network other than the growth of its customer base, but we examine specifications with additional controls in the appendix.

Table 3, column 1, shows the estimation results for equation (1). A 10% increase in the residential customer count is associated with a roughly 2.5% increase in pipeline miles, statistically significant at the 1% level. A 10% increase in the commercial customer count is associated with a 0.3% increase in pipeline miles, statistically significant at the 1% level. The magnitude difference between the residential and commercial estimates is intuitive: as shown in the appendix, the typical utility has 10 times as many residential

Table 3. The Impact of Customer Base Changes on Pipeline Infrastructure

	Pipeline Miles (log) (1)	Pipeline Miles (log) (2)
Residential customers (log)	.249***	
	(.023)	
Commercial customers (log)	.034***	
	(.011)	
Residential customers (log), when growing		.385***
		(.037)
Residential customers (log), when shrinking		–.001
		(.039)
Commercial customers (log), when growing		.028
		(.020)
Commercial customers (log), when shrinking		–.007
		(.016)
Constant	.011***	.003***
	(.000)	(.001)
Observations	9,538	9,538
R^2	.04	.06
Miles per 100 residential customers	1.09	
When growing		1.68
When shrinking		–.01
p-value: null of symmetry:		
Residential		.00
Commercial		.18
Combined		.00

Note. This table shows point estimates and standard errors corresponding to two separate least squares regressions. In both columns the dependent variable is the total number of miles of pipeline mains in logs. The regressions are estimated in differences. The *p*-value rows show the results of tests that the growing and shrinking coefficients are equal to one another. The "miles per 100 customers" rows show the marginal effects at the median values of the dependent variable and the median customer count. The sample includes annual observations from 1997 to 2019, with around 400 utilities per year. Residential customer log changes of more than 0.2 (in absolute value) and commercial log changes of more than 0.5 (in absolute value) are dropped, as they likely indicate service territory changes. The sample is limited to periods when the utility grew or shrank for two or more consecutive years, matching the policy thought experiment in the paper. Alternative samples and specifications are shown in the appendix. Standard errors are clustered by utility.

* Significant at the 10% level.

** Significant at the 5% level.

*** Significant a the 1% level.

customers as commercial customers, so a 1% change in residential customers is a much larger change in customers than is a 1% change in commercial customers. This can be seen by looking at level effects of the estimates at the median values. The elasticity of 0.25 for residential customers translates into 1.1 miles for every 100 residential customers,

as shown at the bottom of the table. The elasticity of 0.03 for commercial customers translates into 1.3 miles for every 100 commercial customers (not shown, for space).

3.2. Asymmetric Impacts

The first regression results, however, mask important differences between periods of customer base growth and loss. Once a pipeline is built, a utility is unlikely to remove it or to stop selling gas via it. This is particularly true if customer base loss is geographically dispersed, for instance, if driven by urban vacancy rates.

We next estimate an asymmetric specification, allowing for differential impacts of customer growth and loss:

$$\Delta M_{i,t} = \alpha + \sum_{s \in R,C} \beta_s^+ (\Delta N_{i,t}^s)^+ + \sum_{s \in R,C} \beta_s (\Delta N_{i,t}^s) + \sum_{s \in R,C} \eta_s \mathbf{1}(\Delta N_{i,t}^s)^+ + \varepsilon_{i,t}. \quad (2)$$

For the sake of brevity, we omit "ln" in the equation above but all variables are in logs as in equation (1). The dependent variable $\Delta M_{i,t}$ is again the log change in pipeline miles for utility i in year t. The coefficient β_s^+ is the impact of the log change in customer counts for sector s (residential or commercial) at utility i ($\Delta N_{i,t}^s$) when the log change is strictly positive, and β_s is the impact when the log change is weakly negative. Because $(\Delta N_{i,t}^s)^+$ is an interaction term between the log change in customer counts $\Delta N_{i,t}^s$ and an indicator for whether that change is positive, we also include this indicator on its own: $\mathbf{1}(\Delta N_{i,t}^s)^+$. We expect the coefficient on this indicator to be close to zero, as we do not expect a differential change in miles for utilities with very slightly positive versus very slightly negative customer count changes.

Results are presented in the second column of table 3. In keeping with figure 3, this specification shows statistically and economically significant asymmetry in the impact of a changing customer base on pipeline infrastructure. A 10% increase in the number of residential customers is associated with a 3.9% increase in pipeline length. This coefficient is precisely estimated, and statistically different from 0.25, the coefficient in column 1. In contrast, for decreases in the number of residential customers, the typical utility sees essentially no decrease in the number of miles; the coefficient is –0.001 and is not statistically different from zero. As shown at the bottom of the table, symmetry can be rejected at the 1% level for the residential specification. As in the symmetric specification, the coefficient for commercial count growth is fairly small, and again, there is essentially no response for commercial loss.

The evidence in table 3 implies less than one-for-one pipeline growth in response to residential customer increases. This is somewhat surprising. However, there are several likely explanations. First, residential customers do not make up all of the utility network; one must also consider commercial customers. That is, when a utility grows its residential customer base by 1%, it is not growing its entire customer base by 1%. So, a test of the linear combination across sectors is a more appropriate comparison. Second, some of the time when utilities are growing, they are adding customers to existing neighborhoods and

therefore not constructing new pipelines. Finally, there may be differences in the timing of when utilities measure the addition of new pipelines versus the addition of new customers (e.g., year-end vs. mid-year). In the appendix, we consider long-run estimates that address these latter two potential explanations, using an error correction model. The long-run results again show an asymmetry, with a larger coefficient when growing (0.65) and a near-zero coefficient when shrinking.

Finally, it is worth noting that the constant is positive and statistically significant in both columns. The positive constant implies that even a utility with flat residential and commercial counts tends to see a modest increase in pipeline miles. This is consistent with some churn within the service territory, for instance, if urban customers leave the city center to move to new suburban developments within the same utility's service territory.

3.3. Finances

We next perform a similar analysis using data on utility revenues. Utilities collect revenue from customers to pay for capital and operating costs, and we want to understand how these revenues respond to changes in the customer base. Part of our motivation for the paper is that many categories of utility expenditures are likely to be "legacy costs" that do not necessarily disappear as customers leave the system.

We use regression specifications very similar to the specifications used for pipeline miles. Specifically, we regress net revenue (total revenue collected minus gas costs, as described above) on customer counts. We begin with a symmetric specification, as in equation (1) and then proceed to an asymmetric specification, as in equation (2). As with the pipeline analysis, we drop large changes in customer counts that likely indicate mergers, acquisitions, and so forth.

These specifications differ from the estimation with pipeline miles in a few ways. First, our sample size is larger, as we can now include the utilities for which we were unable to merge the EIA data on customer counts and revenues with the PHMSA data on pipeline miles. Second, because we observe net revenue separately for the residential and commercial sectors (whereas we only observed combined miles), we can now estimate separate regressions by sector.

These regressions are designed to ask, "If the customer base grows or shrinks, while weather remains unchanged and while the quantity sold to the typical customer remains unchanged, what happens to a utility's revenue net of gas costs?" Accordingly, we introduce three new control variables. We include the log change in quantity sold per customer (also in differences). Utility net revenues are directly impacted by changes in quantity, as the typical utility includes a substantial per-unit mark-up to cover fixed costs. As a result, exogenous changes in quantity consumed per customer as a result of weather changes or economic shocks can substantially change net revenues. In addition, we include weather, both heating degree days and cooling degree days (also in differences). Together, this quantity sold variable and the two weather variables assist in two ways. First, they reduce noise in the net revenue variable and thus improve the precision of our estimates. Second, it is

possible that new customers and departing customers have different consumption patterns. Thus growing or shrinking the customer base could change the average quantity sold and thus net revenues. By controlling for quantity sold per customer, our primary specification purges our estimates of the customer base impact of this effect on average.

Results are shown in table 4 (for brevity, we display only the coefficients on customer counts; point estimates on the control variables are shown in table A6). The first column shows that a 10% change in residential customers is associated with a roughly 6.5% change in residential net revenue. The estimate in column 2 is slightly higher for commercial. These estimates translate into roughly $200 of net revenue per residential customer and $1,000 per commercial customer.

Table 4. The Impact of Customer Base Changes on Net Revenue

	Residential Net Revenue (1)	Commercial Net Revenue (2)	Residential Net Revenue (3)	Commercial Net Revenue (4)
Customers (log)	.65***	.75***		
	(.09)	(.06)		
Customers (log), when growing			1.01***	.86***
			(.13)	(.10)
Customers (log), when shrinking			.47**	.77***
			(.20)	(.11)
Constant	.00*	.00*	.00	.01**
	(.00)	(.00)	(.01)	(.01)
Observations	14,437	14,017	14,437	14,017
R^2	.02	.08	.02	.08
Dollars per customer	211	988		
When growing			328	1,137
When shrinking			152	1,015
p-value: null of symmetry			.02	.53

Note. This table reports point estimates and standard errors corresponding to four separate least squares regressions. The dependent variable in cols. 1 and 3 is net revenue from the residential sector, in logs. The dependent variable in cols. 2 and 4 is net revenue from the commercial sector, in logs. The regressions are estimated in differences. The *p*-value rows show the results of tests that the growing and shrinking coefficients are equal to one another. The "dollars per customer" rows show the marginal effects at the median values of the dependent variable and the median customer count. The sample includes annual observations from 1997 to 2019, with around 600 utilities per year. Residential customer log changes of more than 0.2 (in absolute value) and commercial log changes of more than 0.5 (in absolute value) are dropped, as they may indicate service territory changes. The sample is limited to periods when the utility grew or shrank for two or more consecutive years, matching the policy thought experiment in the paper. Alternative samples and specifications are shown in the appendix. Standard errors are clustered by utility.

* Significant at the 10% level.

** Significant at the 5% level.

*** Significant a the 1% level.

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Columns 3 and 4, however, show marked asymmetry, particularly for residential customers. Although the point estimates suggest less asymmetry for commercial customers, the standard errors are wide enough that we are hesitant to draw strong distinctions between customer classes. A utility that adds 10% more residential customers increases its net revenue by 10%, an elasticity of one. This translates into $328 per customer (as shown at the bottom of the table), roughly matching the median net revenue per customer in our sample (table 1). This is intuitive if utilities do not change their pricing structure when they are growing, so that new customers translate directly into new revenues.

In contrast, a utility that experiences a 10% decrease in residential customers decreases its net revenue by only 5%. It is intuitive that this is not equal to zero (and is statistically different from zero at the 5% level), since costs may fall when a customer departs. These may represent falling costs of service provision (e.g., meter reading becomes easier with fewer customers), or they may represent decreased returns to investors, as we discuss below.

However, it is also important to note that the growing and shrinking estimates are statistically different from one another at the 5% level, as shown in the bottom row of the table. In level terms, losing one customer translates into a revenue decrease of $152, whereas gaining one customer translates into a revenue increase of $328. That is, utilities with shrinking customer bases do not experience shrinking revenues at a one-for-one rate. This asymmetry is interesting and important because it indicates that utility shareholders are not bearing the full brunt of legacy costs. With shrinking utilities, it appears that ratepayers are bearing a large share of these costs—consistent with utilities raising prices to increase total revenue collection per customer for those customers who continue to receive natural gas service.

A hypothetical numerical example is helpful. Suppose a utility initially has 10,000 customers and collects $300 per customer each year, so that its net revenue is $3 million. It then loses 5% of its residential customer base, that is 500 customers. If prices do not change, net revenue would be $2.85 million. But according to the estimates in table 4, the utility's residential net revenue would decrease by 2.5%, leaving it with a net revenue of $2.925 million. This translates into $308 per customer—prices for the remaining customers have risen by about 2.5%. We further explore this under future potential scenarios below.

3.4. Robustness Checks and Additional Specifications

In the appendix, we show a large number of robustness checks and additional specifications, ultimately concluding that our results on the impacts of a changing customer base on pipeline miles and on net revenue collected are robust.

Results for the impact of customer base changes on pipeline miles are shown in table A4. We include utilities with a large fraction of retail choice customers; this adds around 300 observations but essentially does not change the point estimates. We next include large year-on-year customer changes that likely indicate mergers, acquisitions, and so forth.

We next include one-year periods of growth or loss. This has the greatest impact on our observation count of any robustness check—in the raw data, many utility-year observations are one-year blips in either customer growth or customer loss. This is especially true because we drop the observations that experience such a blip in either the residential or the commercial sector. The robustness check that includes these one-year periods yields qualitatively similar coefficients and conclusions. Most importantly, the asymmetry we see in customer growth or loss is still notable in this robustness check. The coefficient on residential customer growth is somewhat smaller, which is intuitive if pipeline miles do not need to grow in response to one-year blips that do not represent sustained customer growth.

We include utilities with small mile counts, which somewhat attenuates the coefficient on growing miles but does not change our conclusions about asymmetry.[13] We next include large changes in miles that may indicate measurement error. Alternatively, we use a more stringent definition of outliers in this variable.

We next limit the sample just to investor-owned utilities, dropping municipal utilities. Alternatively, we limit the sample to medium and large utilities, that is, those with at least 10,000 residential customers in every year. Next we include the additional weather and quantity-per-customer controls that we include in the net revenue specifications. Next we add either year effects or fixed effects, while still estimating the regression in differences.

Across all of these additional specifications, we continue to find an asymmetric impact of customer base changes on miles. The estimates for residential customer growth are all qualitatively similar, and all specifications have comparable statistical significance. The impact of customer loss is generally close to zero. The one exception is the specification that limits the sample to investor-owned utilities. For that specification, we are unable to precisely estimate the impact of residential customer loss because, as we show in table 2, most investor-owned utilities are growing over our sample period.

We similarly estimate several additional specifications for the net revenue variable, concluding that our main results are robust (tables A7, A8). We estimate regressions using alternative samples as we did for the miles specification (e.g., including retail choice, limiting to investor-owned utilities, etc.). In addition, we include a specification that has both residential and commercial counts on the right-hand side, a specification with an alternative net revenue measurement, and a specification that limits the sample to just those utilities for which we observe pipeline miles. Across this broad suite of robustness checks, we continue to estimate a coefficient close to 1 when residential customer count is growing and a coefficient of around 0.5 when the residential customer count is shrinking. As with the miles specification, we lose power on the shrinking coefficient when we limit to investor-owned utilities; we also lose power when we limit to large utilities or when we add fixed effects (akin, in this differences specification, to

13. This is explored in greater depth in table A5.

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utility-specific trends). Commercial results are similarly robust across these additional specifications.

To summarize, we show that growing utilities add new pipeline infrastructure, but utilities with shrinking customer bases continue to maintain the same amount of legacy pipeline infrastructure. In keeping with this, utility revenues rise (with an elasticity of one) when the customer base grows but shrink by a smaller amount when the customer base shrinks. That is, prices for remaining customers rise. We next turn to a discussion of the implications for equity across customers as well as an examination of utility expenditures.

4. DISCUSSION AND POLICY IMPLICATIONS

4.1. Income and Racial Equity

Increasing prices for remaining customers at a shrinking utility will clearly have equity implications. This is true both historically, for the customer base shrinking that we observe in our sample, and in the future, for example, with customers leaving the utility due to building electrification. As customers leave natural gas service, they stop paying for the pipeline infrastructure that they leave behind. How this interacts with income, racial, or other inequality depends on the characteristics of the customers who leave, as well as on the characteristics of the customers who get left behind.

Table 5 describes the eight utilities that experienced the largest loss in residential customers as well as the eight utilities that experienced the largest increase in residential customers. These 16 utilities are generally large utilities (almost all have more than 100,000 residential customers at the beginning of our sample, and the largest serves more than 4 million residential accounts). They are generally investor-owned utilities, with the exception of the municipally operated Philadelphia Gas Works and a municipal utility in Albany, GA. And, they generally experienced prolonged periods of either growth or loss over our time period, as opposed to one-time changes (fig. A2; figs. A1–A8 are available online).

For each utility, we list the largest city served, according to the utility's website. Our data are at the utility level, not household level, and we do not have demographic or socioeconomic information about the composition of customers who exit or enter natural gas service, nor do we have comprehensive information on service territories over time. Nonetheless, broader city-level demographic and socioeconomic information for the largest city served can shed light on the type of communities that have experienced customer loss and gain.

We list four demographic characteristics for each city: the population change over the 2000–2019 period, the percentage of the city's population that is Black or African American, the poverty rate, and the annual per capita income (in thousands of dollars).[14]

14. The socioeconomic variables are reported at the city level by the Census Bureau using data from the American Community Survey five-year estimates; we report vintage year 2019 estimates.

There are several striking features of table 5. First, the utilities with the largest customer losses generally serve cities with declining or flat populations. Several cities experienced large losses in population: Birmingham, AL, and Charleston, WV, each with a drop of 13%; also Mobile, AL, Albany, GA, and Shreveport, LA. In contrast, the utilities with the largest customer gains generally served cities with growing populations: Aurora, IL, experienced a 37% increase in population and Las Vegas 35%. The growing utilities nearly all serve states in the West and Southwest, consistent with regional demographic trends in the United States over this time period.

Second, the utilities with large customer losses overwhelmingly serve cities with large African American populations. With the exceptions of Charleston, WV, and Lawton, OK, the largest cities served by the shrinking utilities have populations that are 40% or more African American. In contrast, the utilities with growing customer bases generally serve cities with much smaller African American populations. A number of economic and social forces may be at play here; Beauregard (2009) identifies several factors responsible for shrinking cities over the 1980–2000 period, including suburbanization, racial antagonisms, and more. For instance, one important force behind migration in the United States has been White flight and suburbanization, the latter frequently racially restricted. While most work has emphasized the postwar period, Crowder and South (2008) and Beauregard (2009) suggest that this legacy continues in more recent decades. Future work could look at whether historical White flight has led to a stranded pipeline infrastructure that must be maintained by the remaining African American population.

Table 5 also shows a pattern of income inequality that is correlated with shrinking or growing customer bases. The median poverty rate in the large cities served by shrinking utilities is 23%, and the median rate for the growing utilities is 16%. Similarly, the median per capita income in the shrinking sample is $27,000, compared to $34,000 in the growing utilities. This pattern matches that explored by Faust et al. (2016), who examine water infrastructure management in four shrinking cities. They focus on the Rust Belt and not the South but, like us, show that the shrinking cities have low incomes, and therefore "shrinking cities face not only a decline in [water] customers but also the inability of the existing customers to afford drastically increasing rates" (133). The pattern is also consistent with the vicious cycle of urban economic decline described by both Faust et al. (2016) and Galster (2017); the latter writes that "selective outflow renders the city increasingly occupied by the disadvantaged," noting also that "out-mobility of disadvantaged households who are African-American or Latino may be further constrained by illegal discrimination in housing markets outside of declining cities" (357).

The evidence on mostly larger, mostly urban utilities in table 5 complements the evidence shown earlier on declining residential customer counts for municipal utilities (table 2), which are typically small and rural. This customer base loss for municipalities is intuitive given the rural depopulation of much of the United States. As Johnson and Lichter (2019, 4) write, "population loss has seemingly become the new demographic norm across broad regions of rural America."

Table 5. Demographic Characteristics of Shrinking and Growing Utilities

State	Utility	Initial Residential Count	Change	Largest City Served	Pop. Change 2009–19	% Black or African American	Poverty Rate	Income per Capita $000's
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
A. Utilities with Largest Customer Loss								
AL	Alabama Gas Corp	423,130	−29,865	Birmingham	−13	70	26	24
AR	Centerpoint Energy Arkla	386,572	−25,949	Little Rock	8	42	17	36
AL	Spire Gulf Inc	95,021	−16,279	Mobile	−7	52	21	27
OK	Centerpoint Energy Arkla	100,850	−13,385	Lawton	0	20	19	24
PA	Philadelphia Gas Works	492,945	−10,100	Philadelphia	5	42	24	28
WV	Hope Gas Inc	111,216	−9,553	Charleston	−13	16	21	35
LA	Centerpoint Energy Entex	116,781	−9,085	Shreveport	−6	57	26	26
GA	Albany Water Gas & Light Comm	16,298	−5,864	Albany	−7	74	31	20

B. Utilities with Largest Customer Gain									
IL	Nicor Gas	1,722,299	342,511	Aurora	37	10	11	31	
NV	Southwest Gas Corporation	337,465	393,567	Las Vegas	35	12	15	31	
UT	Questar Gas Company	560,717	411,496	Salt Lake City	10	3	17	37	
CO	Pub Service Co of Colorado	889,902	419,749	Denver	31	9	13	44	
AZ	Southwest Gas Corporation	598,050	453,019	Phoenix	27	7	18	29	
TX	Centerpoint Energy Entex	1,103,814	545,829	Houston	18	23	20	33	
CA	Pacific Gas	3,493,097	791,719	San Jose	13	3	9	47	
CA	Southern California Gas	4,599,840	1,007,849	Los Angeles	8	9	18	35	

Note. This table describes the eight natural gas utilities in our sample which experienced the largest loss in residential customers along with the eight utilities which experienced the largest gain in residential customers from 1997 to 2019. Columns 3 and 4 list the initial count of residential customers and the change in residential customers over our sample, respectively. The last four columns provide demographic statistics from the US Census Bureau for the largest city served by each utility.

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Overall, we highlight three equity-related implications of our work. All three are suggestive, but future work could explore these on a national scale. First, we show patterns of customer base loss in predominantly African American cities, which may contribute to higher energy bills for urban African American populations. Second, rural depopulation may also lead to a rural/suburban divide in energy bills and infrastructure quality. Finally, if future electrification leads to inequality in energy expenditures (an issue we next explore in depth), it may be worth investigating how these future issues interact with the past inequities described above.

4.2. Simulating Bill Impacts of Customer Exit

As we discuss above, building electrification is emerging as a central policy issue for climate change mitigation. Our results point to a thorny issue during a transition period in which some, but not all, buildings electrify. If building electrification occurs in a geographically dispersed manner, utilities will need to continue to pay for pipeline networks but will have fewer customers to bear these costs. As we show above, shrinking customer bases lead to rising prices for remaining customers, with implications for equity. In this section, we explore potential price impacts in greater detail. We focus on the residential sector, for which the equity implications are clearest, but we note that similar mechanisms are at play in the commercial sector. We assume throughout this analysis that there is no cross-subsidization across sectors, that is, the revenue requirement in the residential sector does not depend on what occurs in the commercial sector, consistent with traditional utility practice.

In figure 4 we plot (thick, middle line) the implications of the estimates from table 4 for a rise in prices under different magnitudes of natural gas customer exit. Specifically, in a scenario in which 0% of residential natural gas customers exit, we assume that the typical customer pays $328 per year in net revenue.[15] Then we assume that each 1% of lost gas customers leads to a 0.53% rise in prices for everyone else, based on the 0.47 coefficient in column 3 of table 4.

Figure 4 shows that bill impacts are small when only a small percentage of customers exit the natural gas sector but increase substantially as a higher percentage of customers exit. To understand why this relationship is nonlinear, imagine that all customers but one exit, and that remaining customer must cover all of the utility's legacy costs. Recent papers on US economy-wide decarbonization assume a rapid electrification of residential buildings (Aas et al. 2020; Larson et al. 2020; National Academies of Sciences, Engineering, and Medicine 2021; Williams et al. 2021). Larson et al. (2020) and Williams et al. (2021) assume something on the order of a 15% reduction in natural gas residential customers by 2030 and 40% or more by 2040. Our estimates imply that customer

15. Our estimate for net revenue at growing utilities in table 4 is $328; it is also similar to the median residential net revenue value of $350 in table 1.

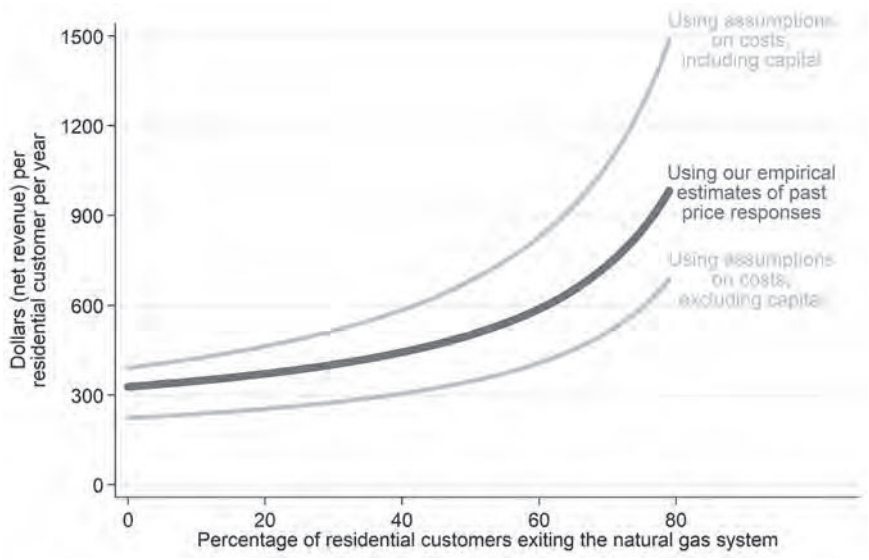

Figure 4. Utility bills rise nonlinearly with customer exit. This figure plots how the net revenue per residential customer (i.e., bill totals net of gas costs) changes as other customers exit, for instance, because they switch to electric heating and cooking. The thick, middle line uses empirical estimates from past utility behavior, specifically the estimates in table 4. The top and bottom lines provide approximate bounds for these estimates, calculated based on financial data from a sample of utilities as described in section 4.3. The upper and lower bounds reflect a representative utility at the beginning and end of the depreciation schedule, respectively. If gas costs were included, it would simply shift all three lines up by a constant amount, equal to around $300 per customer per year (table 6) but fluctuating with weather, macroeconomic conditions, and natural gas wholesale prices. Color version available as an online enhancement.

exit of this level this would translate into annual bill increases of $31 and $116 per customer, respectively. These higher natural gas bills will then prompt additional customer exit, in the natural gas version of the "utility death spiral."[16]

This general pattern is similar to previous calculations by policy analysts. Gridworks (2019) calculates a roughly 100% increase in residential natural gas bills for a 60% decrease in residential gas demand in California (although note that figure includes gas

16. Several previous papers document a negative price elasticity of demand for natural gas. Davis and Muehlegger (2010) estimate short-run elasticities of –0.28 and –0.21 for residential and commercial customers, respectively. Hausman and Kellogg (2015) estimate short-run elasticities of –0.11 and –0.09 and long-run elasticities of –0.20 and –0.23 for residential and commercial customers, respectively. Auffhammer and Rubin (2021) estimate a medium-run elasticity of –0.20. Finally, Davis (2021) shows that natural gas prices also matter for extensive margin decisions, with a 10% increase in natural gas prices increasing adoption of electric heating by 2 percentage points.

commodity costs, which we have not included). As another point of comparison, a California Energy Commission analysis (Aas et al. 2020) describes a scenario in which prices increase by 80% by 2030 and 480% by 2050, although that includes other cost drivers too.

Nonetheless, it is important to emphasize that these calculations are based on our empirical analysis of past customer losses. However, under a transition away from natural gas, the composition of customer exit could be quite different from the historical pattern. Moreover, utility and regulator behavior could change, for example, resulting in larger reductions in maintenance expenditures than have been observed historically. To better understand how the impact of future electrification might differ from the past impact of customer base loss, and to inform potential policy options, we next examine data on expenditure patterns at US natural gas utilities and discuss how different categories of expenditure might change with widespread building electrification.

4.3. Utility Expenditures

In this section, we turn to financial data from an ancillary data source in order to provide additional details about the different categories of utility expenditures. The American Gas Association (AGA), a large trade organization, conducts an annual benchmarking survey of around 80 natural gas distribution utilities. The utilities represented are a mix of investor-owned and municipal utilities. They are not a random sample, but together they represent a substantial portion (around 70%) of all customers nationwide. Details on this AGA report, and the calculations we make using it, are in the appendix.

In table 6, we describe the expenditures of a typical natural gas distribution utility. Perhaps not surprisingly, the single largest expenditure is purchasing natural gas (over $300 per residential customer per year). Recall that our previous analysis netted out this expenditure to focus on fixed costs related to pipelines.

The second largest expenditure for a typical utility (around $170 per residential customer per year) is for past capital expenditures. The largest capital expenditures are main and service pipelines, but examples of smaller categories are compressor station equipment, building structures, tools, and trucks. The capital expenditures category is composed of both annual write-downs of past capital (i.e., depreciation)—around $63 per residential customer per year—and a payment to investors for their return on past capital expenditures (around $105). At any given utility, this amount will depend on depreciation to date as well as the rate of return allowed by utility regulators. These first two categories, expenditures for natural gas and capital expenditures, together account for about two-thirds of total utility expenditures.

The remaining one-third consists of operating expenditures and taxes. The next category ($85 per residential customer per year) is administrative expenses, including salaries to executives, pension payments, and so forth. Distribution operations and maintenance (averaging around $66 per residential customer annually) refers to labor and materials for operating and maintaining the distribution network (pipelines as well

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Table 6. Expenditure Categories for US Natural Gas Distribution Utilities

Category	Example	Average Dollars per Customer Annually	Assumed Portion Leaving with the Customer
Gas cost	Cost of purchasing natural gas	312	1.0
Capital-related expenditures:			
Depreciation	Annual write-down of past capital expenditures	63	.0
Return on net utility plant	Return for investors on past capital expenditures	105	.0
Operations-related expenditures:			
Administrative	Administrative salaries, outside services, pensions, injuries and damages, customer assistance, advertising	85	.5
Distribution operations and maintenance	Maintenance of distribution mains, service lines, and meters	66	.1
Accounts	Meter reading, customer records, and uncollectibles	25	.9
Taxes	Sales, income, property, etc.	47	.6
Total expenditures		703	.6

Note. This table was constructed by the authors based on financial data from the American Gas Association's "2016–2018 Performance Benchmarks for Natural Gas Utilities" report EA 2020-03. The last column shows the assumptions we make regarding what portion of the category's expenditures are eliminated when a customer leaves; for instance, a utility no longer needs to purchase any gas for that customer (first row) but must still recover all of its past capital expenditures (second and third rows). Note that the "Total expenditures" row at the bottom includes gas costs and is therefore higher than the net revenue plotted in fig. 4. The 0.6 calculations in the "Taxes" and "Total" rows reflect a weighted average of the assumed portion for the individual categories. Details on the AGA report and on the assumed portion column are in the appendix.

as customer meters). Finally, utilities have expenditures related to servicing accounts ($25 per residential customer per year), which includes meter reading but also expenses related to nonpayment.

The last column of table 6 shows our assumptions about how each of these categories of expenditure change in response to customer base loss. First, we assume that 100% of expenditures on natural gas are eliminated when a customer exits. The utility no longer needs to procure natural gas on that customer's behalf so these costs are clearly marginal

to the customer. Second, we assume that 0% of past capital expenditures are eliminated when a customer exits, reflecting the fact that these are a sunk cost that must still be recovered even when a customer exits.[17]

Third, we assume that between 10% and 90% of operating expenses are eliminated when a customer exits, with the exact percentage varying across categories. We assume that half of administrative expenses are eliminated but half are not. Pensions, for instance, must still be paid when a customer exits. However, expenditures on customer assistance can presumably decrease as there are fewer customers to assist. In contrast, we assume that almost none of the distribution operations and maintenance expenditures are eliminated—since the pipeline network has not changed, the same amount of maintenance must be conducted for safety to not be compromised.[18] We assume that some are eliminated because, for instance, the departing customer's meter may no longer need the same maintenance. We assume that most customer-related account expenditures are eliminated, as a meter reader is no longer needed for that household. We assume that not all of these expenses are eliminated since, for instance, a utility without internet-connected meters must still send a person down the street to read nearby meters of remaining customers, so the cost of meter reading does not decrease one for one in some cases. For taxes, we use the weighted average portion from the other categories.

Based on these assumptions, we plot two additional lines in figure 4, intended to represent upper and lower bounds. As explained earlier, this figure describes how net revenue per customer would change under increasing levels of customer exit, and the central estimate is based on our empirical estimates in table 4. We construct the bounds using cost information and baseline assumptions from table 6. For the upper bound, we use all cost categories, including the two categories of capital costs. For the lower bound, we include all cost categories except for the two categories of capital costs.

The upper and lower bounds can be thought of as the price paths for a representative utility at the beginning and end of the depreciation schedule. Going forward, natural gas utilities may choose to cease new capital investments if they expect a high degree of building electrification. Without new capital investments, the capital cost component of bills would decrease until eventually reaching zero as these assets are fully depreciated. Thus we would expect the actual price path to be between these upper and lower bounds, but closer to the lower bound in the long run.

Overall, this bounding exercise yields price paths that are remarkably similar to the path we constructed using our empirical estimates. This similarity provides reassurance that our empirical estimates are broadly representative, even though the utilities that experienced customer losses during our sample period tend to be municipally owned,

17. While cost disallowances are relatively rare in practice, there is precedent for public utility commissions to disallow cost recovery, as we discuss in the following section.

18. It is also possible that a struggling utility would cut back on maintenance (Evans and Gilpatric 2017). We discuss potential policy implications in the Conclusion.

smaller, and rural. Probably the most important take-away from the broader analysis is that a considerable portion of capital and operating expenses is not eliminated by customer exit. This is consistent with our empirical analysis of net revenue as well as with these calculations based on financial data, and it implies that under electrification scenarios remaining natural gas customers can expect significantly rising bills.

4.4. Policy Alternatives

The main takeaway from our empirical analysis is that as customers exit natural gas service, this increases bills for customers left behind. These bill increases have important implications for equity, and we show that there has tended historically to be a pronounced pattern in which these remaining customers disproportionately come from disadvantaged groups. In this section, we discuss alternative options for utility financing that could break this historical pattern, and what these alternatives could mean for efficiency and equity.[19]

4.4.1. Changing the Composition of Customer Exit

We first discuss a set of policies that would change the composition of customer exit. For example, one type of policy intervention would be to subsidize building electrification for low-income households or other disadvantaged groups, thereby changing the composition of customer exit (and perhaps accelerating overall electrification). While this approach could improve equity, simply funding low-income electrification projects will still result in higher natural gas bills for remaining users, which may prove burdensome for low- and middle-income customers who do not enroll in the program. Some of these customers may prefer natural gas over electricity (Davis 2021), may fail to qualify if they are middle income (Forrester and Reames 2020), or may have trouble accessing the program (Fowlie et al. 2015; Raissi and Reames 2020). In addition, such a policy by itself would not solve the underlying financial difficulties of the natural gas utility.

A related set of policies would target electrification policies geographically. Targeted electrification has been suggested as one way to reduce ongoing operations and maintenance costs; in this scenario, whole areas are electrified so that entire sections of the pipeline network can be shut down. One could imagine targeting based on safety and climate goals, particularly in areas where aging pipelines would otherwise be replaced to prevent methane leaks and pipeline accidents—incurring capital costs that would need to be paid by future customers. Such a targeted electrification policy could lead to a more equitable or a less equitable transition, depending on which areas are targeted. Of course, this policy alone does not solve the problem of how to pay for system-wide legacy costs.

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19. These alternative policies have been previously discussed in Bilich et al. (2019), Greenlining Institute (2019), Gridworks (2019), Mahone et al. (2019), Aas et al. (2020), Larson et al. (2020), Karas et al. (2021), National Academies of Sciences, Engineering, and Medicine (2021), and Williams et al. (2021).

4.4.2. Changing How Utility Customers Pay

Another set of policies would change how customers pay for natural gas service. For example, one alternative would be to accelerate the depreciation schedules used by utility commissions in rate making. Accelerated depreciation allows the utility to recover capital costs more quickly, meaning that these investments remain in the rate base for fewer years. This approach could reduce the degree to which these capital costs are shifted over time onto a smaller set of remaining customers. However, this approach does not address the problem of ongoing maintenance costs associated with sparsely used pipelines; as we show above, these are not trivial. Another limitation of accelerated depreciation is that it will, in the short term, raise prices for remaining customers even further.

Other related policies would target more directly the underlying incentive problems. Fundamentally, utility financing relies on a stable or growing customer base to recover past costs; in this way, incentives for customer entry and exit are not correctly aligned. One could imagine pricing schemes that correctly align incentives for customer entry and exit. For instance, customers could pay hook-up fees that cover the future stream of capital and operations and maintenance costs, so that if they later exit, they are not leaving remaining customers on the hook.

This approach has some promise but also faces challenges. Utilities have generally wanted to grow their customer base to bring in new sources of revenue, and a high connection fee disincentivizes future growth (Sherman and Visscher 1982).[20] This kind of policy may also face pushback from ratepayer advocates who value energy access.

A closely related alternative would be to charge exit fees. That is, customers departing the system would be asked to cover a portion of the capital and operations and maintenance costs they leave behind. Our empirical analysis implies that exit fees would need to be large—in excess of $1000 per household—if they were to completely cover the present discounted value of legacy costs. Such a solution could be very effective at reducing cost shifts but is likely to be politically and logistically challenging and would, of course, be highly unpopular with customers, who would correctly claim that they were not warned about such fees when they initially signed up for natural gas service. In addition to these substantial obstacles, exit fees would delay the transition of households away from on-site consumption of fossil fuels.

20. It is worth noting that the discussion around widespread customer loss is relatively new—as recently as 2013, some states were instead investigating policy issues related to natural gas distribution extensions, because of low commodity prices induced by fracking. Costello (2013, 35) discusses rate-setting principles in this setting, for instance "growth should pay for itself by requiring new customers to pay the full costs for extending service to their areas"—but does not consider how this principle might account for the potential exit of customers in the future.

4.4.3. Shifting Costs to Utility Owners

There is also the possibility that utility owners would bear some of these legacy costs. For the hundreds of investor-owned and privately owned utilities in the United States, legacy costs could be disallowed or partially disallowed by regulators, thereby mitigating additional price increases. Cost disallowances would shift the burden away from ratepayers and toward shareholders and other owners. Municipal utilities are not privately owned, so this alternative does not apply. There is a large literature in law and economics on the question of what costs can be disallowed by regulators versus what costs they must allow utilities to recover. Prominent court cases like *Hope Natural Gas Co.*, *Market Street Railway*, and *Duquesne Light Co.* have considered this question in a number of different contexts. While *Hope* offers utilities the right to a fair rate of return, the *Market Street* decision by the Supreme Court makes clear that this does not protect a utility from market forces that are rendering its service obsolete. See, for example, Kahn (1997), Graffy and Kihm (2014), and Raskin (2014).

Some of the questions that have arisen in these and related cases are (1) whether the investments were prudent at the time they were made, versus whether the investments continue to be economically viable (i.e., used and useful), (2) whether the utility's very existence is at risk, (3) whether the utility has an obligation to serve remaining customers, and (4) whether the risk faced by the utility arises from market forces or from actions taken by regulators. In some of these cases, commissions have allowed utilities to recover investment costs themselves (i.e., depreciation) but not a rate of return on those investments (Rose 1996). Any whole or partial disallowances would decrease the value of the utility, leading shareholders to bear some of these legacy costs.

It is still too early to say what approach utility commissions will take. From an economic perspective, there are clear efficiency benefits from making sure that shareholders have some "skin in the game." A central tenet of law and economics is that agents should bear the costs of their actions. Utilities are constantly making long-term investments and the threat of disallowances helps encourage utilities to make these decisions efficiently, for example, avoiding expensive pipeline replacement projects in locations undergoing rapid building electrification. On the other hand, it is unrealistic to think that shareholders could be made responsible for the entire legacy gas infrastructure. Disallowing too many of these costs would raise the cost of capital for utilities, making it hard for them to finance basic operations and potentially leading to bankruptcy.

4.4.4. Paying for Costs Elsewhere

In addition, there are policy alternatives that would involve shifting legacy costs out of the natural gas sector altogether. One possibility is that customers of electric utilities could instead cover the transition costs associated with the electrification transition. How this is structured would depend on whether the same utility serves gas and electric customers and, if not, on the way in which each utility is regulated. In the United States there are large numbers of both "single-fuel" (selling only natural gas) and "dual-fuel"

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utilities (selling both natural gas and electricity) (Knittel 2003). An interesting question moving forward is whether dual-fuel utilities might begin cross-subsidizing natural gas customers by increased revenue collection from electricity customers. This type of cross-subsidization has not been widely done historically and tends to go against the utility ethos of "cost allocation." In addition, electricity rates already include considerable fixed costs of their own, resulting in a price per unit of electricity that exceeds social marginal cost in most parts of the United States (Borenstein and Bushnell 2022).

Finally, utility fixed costs could be recovered through the general tax base rather than from utility customers. This could include transfers from federal, state, or local government. Indeed, this is done for other natural monopolies, such as the postal service. This approach has also been proposed for electric utilities facing declining cost recovery because of residential rooftop solar adoption (Borenstein et al. 2021).[21] A variant on this would use cap and trade or carbon tax revenues, rather than the general tax base.[22]

4.4.5. Summary

To summarize, a number of policies have been suggested. Our results can contribute to these discussions in a number of ways. First, by recognizing that the transition difficulties associated with electrification are fundamentally a result of the way that natural monopolies in the United States recover their fixed costs, proposals that address the underlying issue can be crafted. Second, we point out that there are multiple issues to be addressed, and as such multiple policies may be needed: capital cost recovery, ongoing maintenance cost recovery for safety and environmental reasons, and equity issues. Fully addressing all of these will likely require a combination of policies. Finally, researchers and policy makers may be able to learn from successful policies used in other domains (natural gas, electricity, water, transportation), since the underlying market structure is similar and the underlying economic issues nearly the same.

5. CONCLUSION

The utility business is often thought of as stable and predictable. But we show that US natural gas utilities have experienced a surprisingly large amount of recent change, with many utilities consistently gaining customers while other utilities consistently lost customers over our sample period, 1997–2019. Our paper leverages these changes to test

21. Beecher (2020) also discusses the possibility of funding fixed costs via local property taxes, arguing that it may be less regressive than current pricing structures (although note that local taxes would not decouple cost recovery from migration impacts).

22. Such a policy has been proposed for low-income energy assistance; see Fowlie (2021). A related policy has also been proposed for a more general reform of electricity sector pricing (Shawhan 2016). The pros and cons of recovering fixed costs through the general tax base are discussed in Viscusi et al. (2005)—particularly political economy questions and incentives to control costs.

how utility operations and finances evolve during growth and loss. We show that utilities expand the distribution network during years of customer growth but rarely shrink the network during periods of customer loss. Moreover, we find that utility revenues increase one for one during years of growth but decrease by only half as much during years of loss, implying that remaining customers make up the difference through increased prices.

These dynamics have important implications for a growing set of climate policies aimed at transitioning households and firms away from natural gas toward electricity. We show that during our sample period the utilities experiencing customer losses tended to be in cities with higher poverty rates and a higher percentage of African American residents. Future energy transitions will not follow the exact same pattern, but our results nonetheless highlight the potential for bill impacts to be distributed across households in ways that exacerbate existing societal inequalities. In addition, we use simulation evidence and ancillary data on typical expenditures for US natural gas utilities to show the large potential magnitude of bill impacts. Based on our empirical estimates, for example, we show that bills can be expected to increase by $115 dollars per year in response to 40% of residential customers exiting the system. In our calculations, residential bills increase sharply and nonlinearly in response to additional customer exit.

These dynamics also have major implications for efficiency. A central theme in energy economics is the importance of pricing energy efficiently (Borenstein and Bushnell 2022). Putting more fixed costs into retail prices threatens to increase deadweight loss for remaining customers. At the same time, higher retail prices for natural gas will also accelerate the transition away from natural gas, prompting further exits, and thus additional price increases, in the natural gas version of the "utility death spiral." Of course, if the environmental externalities of natural gas are very large, this is a "virtuous cycle" in that it accelerates decarbonization. While these dynamics will not last forever, an energy transition of this magnitude affects a large number of US households and businesses, so it is critical to trace out the implications for both efficiency and equity.

Our findings are also relevant for ongoing policy debates about how to handle aging infrastructure in the natural gas system, which carries safety risks and environmental risks. Several of the states that are leading on building electrification are also states working to ameliorate methane leaks and explosion risks (e.g., California, Massachusetts, and New York). Future work could examine the optimal suite of policies to meet multiple goals, especially in older utility service territories with aging pipelines. Future work could also investigate whether there are perverse incentives for utilities with customer base loss—either to cut back on important maintenance, as in Evans and Gilpatric (2017), or to overinvest in capital-intensive replacement projects to earn a future rate of return (Averch and Johnson 1962).

Finally, it is worth highlighting that this issue of legacy utility costs is not unique to this particular sector. While our analysis focuses on natural gas distribution utilities, customer exit raises similar challenges for funding inter- and intrastate natural gas pipeline

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infrastructure. As the amount of gas flowing through these long-distance pipelines decreases, the fixed costs associated with these investments are spread over a smaller number of customers. The extent to which this occurs in the future depends not just on what happens with building electrification but also on whether a transition away from natural gas occurs in the industrial and electric power sectors. More generally, our work highlights a broader dynamic that can occur in many sectors with large fixed costs, including public transportation, water distribution, mail delivery, and traditional telephone service.

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PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 904

Staff's Line Extension Allowance Model

April 18, 2024

NW Natural
Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2025
Workpaper: Line Extension Allowance Model - Supplemental
Concentric Energy Advisors
Supplemental Filing Workpaper for NW Natural/2000, Kravitz-Therrien
UG 490 OPUC DR 378 Attachment 2

Directives in Order No. 22-388:

- The company's best reasonable estimate of present and future CPP compliance costs;
- An analysis of how each new customer addition changes the costs of CPP compliance for other customers;
- An explanation of how the proposed LEA incorporates and recognizes the costs of CPP compliance;
- An analysis supporting the company's assumptions about the expected time frame over which new customers will remain on the system, and how changing policy dynamics were factored in; and
- A demonstration of the expected year-by-year economic impact on existing customers from the addition of new customers under the proposed LEA, such that the "breakeven" year is shown, along with the costs and benefits expected in other years, and a demonstration of when rate-based investments for customer additions covered by the LEA are depreciated and removed.

Testimony Exhibits*:	Description:
Exhibit 1902R	DCF Summary Example

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Exhibit 1903	Existing System Revenue Requirements
Exhibit 1904	New System Non-Growth Capital Expenditures Revenue Requirements
Exhibit 1905R	Supporting DCF Assumptions
Exhibit 1906R	CPP Proxy Costs
Exhibit 1907R	Economic Impact on Existing Customers

**Note: Exhibits with an "R" indicate revised exhibits for Supplemental Testimony. See tabs in this workbook for these exhibits with formulae intact.*

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DCF - Exh 1902R (2001) Page 3 of 51

			Year 1	Year 2	Year 3	Year 4	Year 5
1	Revenue from New Connection Tariff	*Exh 1905R*	684	1,026	1,026	1,026	1,026
2	Proxy CPP Revenue	*Exh 1906R*	28	41	488	541	667
3	Proxy CPP Cost	*Exh 1906R*	(335)	(335)	(3,000)	(3,000)	(3,000)
4	Nominal Change in Base Rate Revenue per Customer	*Exh 1903*	0	(22)	(44)	(66)	(88)
5	Contribution to New Non-Growth Capex	*Exh 1904*	44	101	149	192	233
6	Operations & Maintenance		(79)	(79)	(79)	(79)	(79)
7	Franchise Tax	2.74%	(19)	(28)	(28)	(28)	(28)
8	Property Tax	1.50%	66	62	62	62	62
9	Net Before Taxes		389	766	(1,426)	(1,352)	(1,207)
10	Income Tax	27.00%	105	207	(385)	(365)	(326)
11	Net After Tax		284	559	(1,041)	(987)	(881)
12	Tax Benefit on Investment		(45)	(86)	(80)	(74)	(68)
13	Total Operating Cash (ROR Analysis)	$4,419	239	473	(1,121)	(1,060)	(950)

		Rate	Year 1	Year 2	Year 3	Year 4	Year 5
1	Plant		(4,419)	(4,419)	(4,419)	(4,419)	(4,419)
2	Depreciation (per model term)	6.667%	295	295	295	295	295
3	Net Plant		(4,124)	(4,124)	(4,124)	(4,124)	(4,124)
4	Deferred Taxes		35	(51)	(131)	(205)	(273)
5	Net Rate Base		(4,159)	(4,073)	(3,993)	(3,920)	(3,851)
6	Average Rate Base		(4,289)	(4,116)	(4,033)	(3,956)	(3,886)
	Basis for interest expense		-2,145	-2,058	-2,017	-1,978	-1,943

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			Year 1	Year 2	Year 3	Year 4	Year 5
Tax Depreciation			**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**
1	**Tax Depreciation Rate**		3.75%	7.22%	6.68%	6.18%	5.71%
2	**Plant Additions**		(4,419)				
3	**Total Tax Depreciation**		(166)	(319)	(295)	(273)	(252)
4	**Tax Benefit @**	27.00%	(45)	(86)	(80)	(74)	(68)
Book Depreciation							
1	**Book Depreciation Rate**		6.67%	6.67%	6.67%	6.67%	6.67%
2	**Plant Additions**		(4,419)				
3	**Book Depreciation**		(295)	0	0	0	0
4	**Total Book Depreciation**		(295)	0	0	0	0
5	**Total Tax Depreciation**		(166)	(319)	(295)	(273)	(252)
6	**Difference**		129	(319)	(295)	(273)	(252)
7	**Deferred Taxes**	27.00%	35	(86)	(80)	(74)	(68)
	20 year MACRS		3.75%	7.22%	6.68%	6.18%	5.71%

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			Year 6	Year 7	Year 8	Year 9	Year 10
1	Revenue from New Connection Tariff	*Exh 1905R*	1,026	1,026	1,026	1,026	1,026
2	Proxy CPP Revenue	*Exh 1906R*	792	873	1,004	1,134	1,265
3	Proxy CPP Cost	*Exh 1906R*	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)
4	Nominal Change in Base Rate Revenue per Customer	*Exh 1903*	(110)	(132)	(155)	(177)	(199)
5	Contribution to New Non-Growth Capex	*Exh 1904*	269	302	333	362	390
6	Operations & Maintenance		(79)	(79)	(79)	(79)	(79)
7	Franchise Tax	2.74%	(28)	(28)	(28)	(28)	(28)
8	Property Tax	1.50%	62	62	62	62	62
9	Net Before Taxes		(1,069)	(977)	(837)	(699)	(563)
10	Income Tax	27.00%	(289)	(264)	(226)	(189)	(152)
11	Net After Tax		(780)	(713)	(611)	(510)	(411)
12	Tax Benefit on Investment		(63)	(58)	(54)	(53)	(53)
13	Total Operating Cash (ROR Analysis)	$4,419	(843)	(771)	(665)	(564)	(464)

		Rate	Year 6	Year 7	Year 8	Year 9	Year 10
1	Plant		(4,419)	(4,419)	(4,419)	(4,419)	(4,419)
2	Depreciation (per model term)	6.667%	295	295	295	295	295
3	Net Plant		(4,124)	(4,124)	(4,124)	(4,124)	(4,124)
4	Deferred Taxes		(336)	(394)	(448)	(501)	(555)
5	Net Rate Base		(3,788)	(3,730)	(3,676)	(3,623)	(3,570)
6	Average Rate Base		(3,820)	(3,759)	(3,703)	(3,649)	(3,596)
	Basis for interest expense		-1,910	-1,880	-1,852	-1,825	-1,798

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			Year 6	Year 7	Year 8	Year 9	Year 10
Tax Depreciation			**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**
1	**Tax Depreciation Rate**		5.29%	4.89%	4.52%	4.46%	4.46%
2	**Plant Additions**						
3	**Total Tax Depreciation**		(234)	(216)	(200)	(197)	(197)
4	**Tax Benefit @**	27.00%	(63)	(58)	(54)	(53)	(53)
Book Depreciation							
1	**Book Depreciation Rate**		6.67%	6.67%	6.67%	6.67%	6.67%
2	**Plant Additions**						
3	**Book Depreciation**		0	0	0	0	0
4	**Total Book Depreciation**		0	0	0	0	0
5	**Total Tax Depreciation**		(234)	(216)	(200)	(197)	(197)
6	**Difference**		(234)	(216)	(200)	(197)	(197)
7	**Deferred Taxes**	27.00%	(63)	(58)	(54)	(53)	(53)
	20 year MACRS		5.29%	4.89%	4.52%	4.46%	4.46%

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			Year 11	Year 12	Year 13	Year 14	Year 15
1	Revenue from New Connection Tariff	*Exh 1905R*	1,026	1,026	1,026	1,026	1,026
2	Proxy CPP Revenue	*Exh 1906R*	1,395	1,481	1,566	1,652	1,738
3	Proxy CPP Cost	*Exh 1906R*	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)
4	Nominal Change in Base Rate Revenue per Customer	*Exh 1903*	(221)	(243)	(265)	(287)	(309)
5	Contribution to New Non-Growth Capex	*Exh 1904*	416	440	462	483	502
6	Operations & Maintenance		(79)	(79)	(79)	(79)	(79)
7	Franchise Tax	2.74%	(28)	(28)	(28)	(28)	(28)
8	Property Tax	1.50%	62	62	62	62	62
9	Net Before Taxes		(429)	(341)	(255)	(171)	(88)
10	Income Tax	27.00%	(116)	(92)	(69)	(46)	(24)
11	Net After Tax		(313)	(249)	(186)	(125)	(64)
12	Tax Benefit on Investment		(53)	(53)	(53)	(53)	(53)
13	Total Operating Cash (ROR Analysis)	$4,419	(366)	(302)	(239)	(178)	(118)

		Rate	Year 11	Year 12	Year 13	Year 14	Year 15
1	Plant		(4,419)	(4,419)	(4,419)	(4,419)	(4,419)
2	Depreciation (per model term)	6.667%	295	295	295	295	295
3	Net Plant		(4,124)	(4,124)	(4,124)	(4,124)	(4,124)
4	Deferred Taxes		(608)	(661)	(714)	(768)	(821)
5	Net Rate Base		(3,516)	(3,463)	(3,410)	(3,357)	(3,303)
6	Average Rate Base		(3,543)	(3,490)	(3,437)	(3,383)	(3,330)
	Basis for interest expense		-1,771	-1,745	-1,718	-1,692	-1,665

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			Year 11	Year 12	Year 13	Year 14	Year 15
Tax Depreciation			**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**
1	**Tax Depreciation Rate**		4.46%	4.46%	4.46%	4.46%	4.46%
2	**Plant Additions**						
3	**Total Tax Depreciation**		(197)	(197)	(197)	(197)	(197)
4	**Tax Benefit @**	27.00%	(53)	(53)	(53)	(53)	(53)
Book Depreciation							
1	**Book Depreciation Rate**		6.67%	6.67%	6.67%	6.67%	6.67%
2	**Plant Additions**						
3	**Book Depreciation**		0	0	0	0	0
4	**Total Book Depreciation**		0	0	0	0	0
5	**Total Tax Depreciation**		(197)	(197)	(197)	(197)	(197)
6	**Difference**		(197)	(197)	(197)	(197)	(197)
7	**Deferred Taxes**	27.00%	(53)	(53)	(53)	(53)	(53)
	20 year MACRS		4.46%	4.46%	4.46%	4.46%	4.46%

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			Year 16	Year 17	Year 18	Year 19	Year 20
1	Revenue from New Connection Tariff	*Exh 1905R*	1,026	1,026	1,026	1,026	1,026
2	Proxy CPP Revenue	*Exh 1906R*	1,823	1,909	1,994	2,080	2,166
3	Proxy CPP Cost	*Exh 1906R*	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)
4	Nominal Change in Base Rate Revenue per Customer	*Exh 1903*	(585)	(585)	(585)	(585)	(585)
5	Contribution to New Non-Growth Capex	*Exh 1904*	519	535	549	561	571
6	Operations & Maintenance		(79)	(79)	(79)	(79)	(79)
7	Franchise Tax	2.74%	(28)	(28)	(28)	(28)	(28)
8	Property Tax	1.50%	62	62	62	62	62
9	Net Before Taxes		(261)	(160)	(61)	37	133
10	Income Tax	27.00%	(70)	(43)	(16)	10	36
11	Net After Tax		(191)	(117)	(44)	27	97
12	Tax Benefit on Investment		(53)	(53)	(53)	(53)	(53)
13	Total Operating Cash (ROR Analysis)	$4,419	(244)	(170)	(97)	(26)	44

		Rate	Year 16	Year 17	Year 18	Year 19	Year 20
1	Plant		(4,419)	(4,419)	(4,419)	(4,419)	(4,419)
2	Depreciation (per model term)	6.667%	295	295	295	295	295
3	Net Plant		(4,124)	(4,124)	(4,124)	(4,124)	(4,124)
4	Deferred Taxes		(874)	(927)	(981)	(1,034)	(1,087)
5	Net Rate Base		(3,250)	(3,197)	(3,144)	(3,090)	(3,037)
6	Average Rate Base		(3,277)	(3,224)	(3,170)	(3,117)	(3,064)
	Basis for interest expense		-1,638	-1,612	-1,585	-1,559	-1,532

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			Year 16	Year 17	Year 18	Year 19	Year 20
Tax Depreciation			**Year 16**	**Year 17**	**Year 18**	**Year 19**	**Year 20**
1	**Tax Depreciation Rate**		4.46%	4.46%	4.46%	4.46%	4.46%
2	**Plant Additions**						
3	**Total Tax Depreciation**		(197)	(197)	(197)	(197)	(197)
4	**Tax Benefit @**	27.00%	(53)	(53)	(53)	(53)	(53)
Book Depreciation							
1	**Book Depreciation Rate**		6.67%	6.67%	6.67%	6.67%	6.67%
2	**Plant Additions**						
3	**Book Depreciation**		0	0	0	0	0
4	**Total Book Depreciation**		0	0	0	0	0
5	**Total Tax Depreciation**		(197)	(197)	(197)	(197)	(197)
6	**Difference**		(197)	(197)	(197)	(197)	(197)
7	**Deferred Taxes**	27.00%	(53)	(53)	(53)	(53)	(53)
	20 year MACRS		4.46%	4.46%	4.46%	4.46%	4.46%

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			Year 21	Year 22	Year 23	Year 24	Year 25
1	Revenue from New Connection Tariff	*Exh 1905R*	1,026	1,026	1,026	1,026	1,026
2	Proxy CPP Revenue	*Exh 1906R*	2,251	2,337	2,422	2,508	2,593
3	Proxy CPP Cost	*Exh 1906R*	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)
4	Nominal Change in Base Rate Revenue per Customer	*Exh 1903*	(585)	(585)	(585)	(585)	(585)
5	Contribution to New Non-Growth Capex	*Exh 1904*	580	587	594	600	605
6	Operations & Maintenance		(79)	(79)	(79)	(79)	(79)
7	Franchise Tax	2.74%	(28)	(28)	(28)	(28)	(28)
8	Property Tax	1.50%	62	62	62	62	62
9	Net Before Taxes		227	320	413	504	594
10	Income Tax	27.00%	61	87	111	136	161
11	Net After Tax		166	234	301	368	434
12	Tax Benefit on Investment		(27)	0	0	0	0
13	Total Operating Cash (ROR Analysis)	$4,419	139	234	301	368	434

		Rate	Year 21	Year 22	Year 23	Year 24	Year 25
1	Plant		(4,419)	(4,419)	(4,419)	(4,419)	(4,419)
2	Depreciation (per model term)	6.667%	295	295	295	295	295
3	Net Plant		(4,124)	(4,124)	(4,124)	(4,124)	(4,124)
4	Deferred Taxes		(1,114)	(1,114)	(1,114)	(1,114)	(1,114)
5	Net Rate Base		(3,011)	(3,011)	(3,011)	(3,011)	(3,011)
6	Average Rate Base		(3,024)	(3,011)	(3,011)	(3,011)	(3,011)
	Basis for interest expense		-1,512	-1,505	-1,505	-1,505	-1,505

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			Year 21	Year 22	Year 23	Year 24	Year 25
Tax Depreciation			**Year 21**	**Year 22**	**Year 23**	**Year 24**	**Year 25**
1	**Tax Depreciation Rate**		2.23%	0.00%	0.00%	0.00%	0.00%
2	**Plant Additions**						
3	**Total Tax Depreciation**		(99)	0	0	0	0
4	**Tax Benefit @**	27.00%	(27)	0	0	0	0
Book Depreciation							
1	**Book Depreciation Rate**		6.67%	6.67%	6.67%	6.67%	6.67%
2	**Plant Additions**						
3	**Book Depreciation**		0	0	0	0	0
4	**Total Book Depreciation**		0	0	0	0	0
5	**Total Tax Depreciation**		(99)	0	0	0	0
6	**Difference**		(99)	0	0	0	0
7	**Deferred Taxes**	27.00%	(27)	0	0	0	0
	20 year MACRS		2.23%	0.00%	0.00%	0.00%	0.00%

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	Description		Year 1	Year 2	Year 3
	Revenue Requirement Calculations				
1	Gross Plant		$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881
2	Accumulated Depreciation		$ (1,590,754,661)	$ (1,751,597,209)	$ (1,912,439,757)
3	Net Plant		$ 2,412,638,220	$ 2,251,795,672	$ 2,090,953,124
4	Deferred Taxes		$ (435,773,775)	$ (406,722,190)	$ (377,670,605)
5	Average Rate Base (Plant related)		$ 1,976,864,445	$ 1,845,073,482	$ 1,713,282,519
6	Pre-Tax ROR		8.7947%	8.7947%	8.7947%
7	Return and Taxes		$ 173,859,475	$ 162,268,843	$ 150,678,211
8	Book Depreciation		160,842,548	160,842,548	160,842,548
9	O&M		539,667,000	539,667,000	539,667,000
10	Property Taxes	1.5%	36,189,573	33,776,935	31,364,297
11	Franchise Tax and Comm Fees	2.7%	25,661,801	25,267,154	24,872,507
12	Annual Revenue Requirement		$ 936,220,397	$ 921,822,480	$ 907,424,564
13	No. of Customers		652,270	652,270	652,270
14	Existing Plant Revenue Requirement Per Customer		$ 1,435.33	$ 1,413.25	$ 1,391.18
15	YoY Change			$ (22.07)	$ (22.07)
16	Cumulative Change		$ -	$ (22.07)	$ (44.15)
17	Depreciation Expense (based on model term rate)	6.67%	$ 160,842,548	$ 160,842,548	$ 160,842,548
18	Deferred Tax Amortization (based on model term rate)		$ 29,051,585	$ 29,051,585	$ 29,051,585
19	Net Utility Plant		$ 1,964,464,000		

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	Description	Year 4	Year 5	Year 6	Year 7
	Revenue Requirement Calculations				
1	Gross Plant	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881
2	Accumulated Depreciation	$ (2,073,282,305)	$ (2,234,124,853)	$ (2,394,967,401)	$ (2,555,809,949)
3	Net Plant	$ 1,930,110,576	$ 1,769,268,028	$ 1,608,425,480	$ 1,447,582,932
4	Deferred Taxes	$ (348,619,020)	$ (319,567,435)	$ (290,515,850)	$ (261,464,265)
5	Average Rate Base (Plant related)	$ 1,581,491,556	$ 1,449,700,593	$ 1,317,909,630	$ 1,186,118,667
6	Pre-Tax ROR	8.7947%	8.7947%	8.7947%	8.7947%
7	Return and Taxes	$ 139,087,580	$ 127,496,948	$ 115,906,316	$ 104,315,685
8	Book Depreciation	160,842,548	160,842,548	160,842,548	160,842,548
9	O&M	539,667,000	539,667,000	539,667,000	539,667,000
10	Property Taxes	28,951,659	26,539,020	24,126,382	21,713,744
11	Franchise Tax and Comm Fees	24,477,860	24,083,213	23,688,567	23,293,920
12	Annual Revenue Requirement	$ 893,026,647	$ 878,628,730	$ 864,230,813	$ 849,832,896
13	No. of Customers	652,270	652,270	652,270	652,270
14	Existing Plant Revenue Requirement Per Customer	$ 1,369.11	$ 1,347.03	$ 1,324.96	$ 1,302.89
15	YoY Change	$ (22.07)	$ (22.07)	$ (22.07)	$ (22.07)
16	Cumulative Change	$ (66.22)	$ (88.29)	$ (110.37)	$ (132.44)
17	Depreciation Expense (based on model term rate)	$ 160,842,548	$ 160,842,548	$ 160,842,548	$ 160,842,548
18	Deferred Tax Amortization (based on model term rate)	$ 29,051,585	$ 29,051,585	$ 29,051,585	$ 29,051,585
19	Net Utility Plant				

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	Description	Year 8	Year 9	Year 10	Year 11
	Revenue Requirement Calculations				
1	Gross Plant	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881
2	Accumulated Depreciation	$ (2,716,652,497)	$ (2,877,495,045)	$ (3,038,337,593)	$ (3,199,180,141)
3	Net Plant	$ 1,286,740,384	$ 1,125,897,836	$ 965,055,288	$ 804,212,740
4	Deferred Taxes	$ (232,412,680)	$ (203,361,095)	$ (174,309,510)	$ (145,257,925)
5	Average Rate Base (Plant related)	$ 1,054,327,704	$ 922,536,741	$ 790,745,778	$ 658,954,815
6	Pre-Tax ROR	8.7947%	8.7947%	8.7947%	8.7947%
7	Return and Taxes	$ 92,725,053	$ 81,134,422	$ 69,543,790	$ 57,953,158
8	Book Depreciation	160,842,548	160,842,548	160,842,548	160,842,548
9	O&M	539,667,000	539,667,000	539,667,000	539,667,000
10	Property Taxes	19,301,106	16,888,468	14,475,829	12,063,191
11	Franchise Tax and Comm Fees	22,899,273	22,504,626	22,109,979	21,715,332
12	Annual Revenue Requirement	$ 835,434,980	$ 821,037,063	$ 806,639,146	$ 792,241,229
13	No. of Customers	652,270	652,270	652,270	652,270
14	Existing Plant Revenue Requirement Per Customer	$ 1,280.81	$ 1,258.74	$ 1,236.67	$ 1,214.59
15	YoY Change	$ (22.07)	$ (22.07)	$ (22.07)	$ (22.07)
16	Cumulative Change	$ (154.51)	$ (176.59)	$ (198.66)	$ (220.74)
17	Depreciation Expense (based on model term rate)	$ 160,842,548	$ 160,842,548	$ 160,842,548	$ 160,842,548
18	Deferred Tax Amortization (based on model term rate)	$ 29,051,585	$ 29,051,585	$ 29,051,585	$ 29,051,585
19	Net Utility Plant				

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	Description	Year 12	Year 13	Year 14	Year 15
	Revenue Requirement Calculations				
1	Gross Plant	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881
2	Accumulated Depreciation	$ (3,360,022,689)	$ (3,520,865,237)	$ (3,681,707,785)	$ (3,842,550,333)
3	Net Plant	$ 643,370,192	$ 482,527,644	$ 321,685,096	$ 160,842,548
4	Deferred Taxes	$ (116,206,340)	$ (87,154,755)	$ (58,103,170)	$ (29,051,585)
5	Average Rate Base (Plant related)	$ 527,163,852	$ 395,372,889	$ 263,581,926	$ 131,790,963
6	Pre-Tax ROR	8.7947%	8.7947%	8.7947%	8.7947%
7	Return and Taxes	$ 46,362,527	$ 34,771,895	$ 23,181,263	$ 11,590,632
8	Book Depreciation	160,842,548	160,842,548	160,842,548	160,842,548
9	O&M	539,667,000	539,667,000	539,667,000	539,667,000
10	Property Taxes	9,650,553	7,237,915	4,825,276	2,412,638
11	Franchise Tax and Comm Fees	21,320,685	20,926,038	20,531,391	20,136,745
12	Annual Revenue Requirement	$ 777,843,313	$ 763,445,396	$ 749,047,479	$ 734,649,562
13	No. of Customers	652,270	652,270	652,270	652,270
14	Existing Plant Revenue Requirement Per Customer	$ 1,192.52	$ 1,170.44	$ 1,148.37	$ 1,126.30
15	YoY Change	$ (22.07)	$ (22.07)	$ (22.07)	$ (22.07)
16	Cumulative Change	$ (242.81)	$ (264.88)	$ (286.96)	$ (309.03)
17	Depreciation Expense (based on model term rate)	$ 160,842,548	$ 160,842,548	$ 160,842,548	$ 160,842,548
18	Deferred Tax Amortization (based on model term rate)	$ 29,051,585	$ 29,051,585	$ 29,051,585	$ 29,051,585
19	Net Utility Plant				

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	Description	Year 16	Year 17	Year 18	Year 19
	Revenue Requirement Calculations				
1	Gross Plant	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881
2	Accumulated Depreciation	$ (4,003,392,881)	$ (4,003,392,881)	$ (4,003,392,881)	$ (4,003,392,881)
3	Net Plant	$ -	$ -	$ -	$ -
4	Deferred Taxes	$ -	$ -	$ -	$ -
5	Average Rate Base (Plant related)	$ -	$ -	$ -	$ -
6	Pre-Tax ROR	8.7947%	8.7947%	8.7947%	8.7947%
7	Return and Taxes	$ -	$ -	$ -	$ -
8	Book Depreciation	-	-	-	-
9	O&M	539,667,000	539,667,000	539,667,000	539,667,000
10	Property Taxes	-	-	-	-
11	Franchise Tax and Comm Fees	15,209,155	15,209,155	15,209,155	15,209,155
12	Annual Revenue Requirement	$ 554,876,155	$ 554,876,155	$ 554,876,155	$ 554,876,155
13	No. of Customers	652,270	652,270	652,270	652,270
14	Existing Plant Revenue Requirement Per Customer	$ 850.69	$ 850.69	$ 850.69	$ 850.69
15	YoY Change	$ (275.61)	$ -	$ -	$ -
16	Cumulative Change	$ (584.64)	$ (584.64)	$ (584.64)	$ (584.64)
17	Depreciation Expense (based on model term rate)	$ 160,842,548	$ 160,842,548	$ 160,842,548	$ 160,842,548
18	Deferred Tax Amortization (based on model term rate)	$ 29,051,585	$ 29,051,585	$ 29,051,585	$ 29,051,585
19	Net Utility Plant				

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	Description	Year 20	Year 21	Year 22	Year 23
	Revenue Requirement Calculations				
1	Gross Plant	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881
2	Accumulated Depreciation	$ (4,003,392,881)	$ (4,003,392,881)	$ (4,003,392,881)	$ (4,003,392,881)
3	Net Plant	$ -	$ -	$ -	$ -
4	Deferred Taxes	$ -	$ -	$ -	$ -
5	Average Rate Base (Plant related)	$ -	$ -	$ -	$ -
6	Pre-Tax ROR	8.7947%	8.7947%	8.7947%	8.7947%
7	Return and Taxes	$ -	$ -	$ -	$ -
8	Book Depreciation	-	-	-	-
9	O&M	539,667,000	539,667,000	539,667,000	539,667,000
10	Property Taxes	-	-	-	-
11	Franchise Tax and Comm Fees	15,209,155	15,209,155	15,209,155	15,209,155
12	Annual Revenue Requirement	$ 554,876,155	$ 554,876,155	$ 554,876,155	$ 554,876,155
13	No. of Customers	652,270	652,270	652,270	652,270
14	Existing Plant Revenue Requirement Per Customer	$ 850.69	$ 850.69	$ 850.69	$ 850.69
15	YoY Change	$ -	$ -	$ -	$ -
16	Cumulative Change	$ (584.64)	$ (584.64)	$ (584.64)	$ (584.64)
17	Depreciation Expense (based on model term rate)	$ 160,842,548	$ 160,842,548	$ 160,842,548	$ 160,842,548
18	Deferred Tax Amortization (based on model term rate)	$ 29,051,585	$ 29,051,585	$ 29,051,585	$ 29,051,585
19	Net Utility Plant				

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	Description	Year 24	Year 25
	Revenue Requirement Calculations		
1	Gross Plant	$ 4,003,392,881	$ 4,003,392,881
2	Accumulated Depreciation	$ (4,003,392,881)	$ (4,003,392,881)
3	Net Plant	$ -	$ -
4	Deferred Taxes	$ -	$ -
5	Average Rate Base (Plant related)	$ -	$ -
6	Pre-Tax ROR	8.7947%	8.7947%
7	Return and Taxes	$ -	$ -
8	Book Depreciation	-	-
9	O&M	539,667,000	539,667,000
10	Property Taxes	-	-
11	Franchise Tax and Comm Fees	15,209,155	15,209,155
12	Annual Revenue Requirement	$ 554,876,155	$ 554,876,155
13	No. of Customers	652,270	652,270
14	Existing Plant Revenue Requirement Per Customer	$ 850.69	$ 850.69
15	YoY Change	$ -	$ -
16	Cumulative Change	$ (584.64)	$ (584.64)
17	Depreciation Expense (based on model term rate)	$ 160,842,548	$ 160,842,548
18	Deferred Tax Amortization (based on model term rate)	$ 29,051,585	$ 29,051,585
19	Net Utility Plant		

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	Description		Year 1	Year 2	Year 3	Year 4
1	**Rate Base Calculation**					
2	Capex (oregon share @90%)		$ 227,700,000	$ 227,700,000	$ 191,700,000	$ 191,700,000
3	Cumulative Capex		$ 227,700,000	$ 455,400,000	$ 647,100,000	$ 838,800,000
4	Accumulated Depreciation		(15,180,000)	(45,540,000)	(88,680,000)	(144,600,000)
5	Net Plant		$ 212,520,000	$ 409,860,000	$ 558,420,000	$ 694,200,000
6	Deferred Tax Reserve		1,793,403	3,247,187	4,411,075	5,929,745
7	Year End Rate Base Additions		$ 214,313,403	$ 413,107,187	$ 562,831,075	$ 700,129,745
	Revenue Requirement Calculations					
8	Average Rate Base		$ 107,156,702	$ 313,710,295	$ 487,969,131	$ 631,480,410
9	Pre-Tax ROR		8.7947%	8.7947%	8.7947%	8.7947%
10	Return and Taxes		$ 9,424,120	$ 27,589,907	$ 42,915,465	$ 55,536,864
11	Book Depreciation	6.7%	15,180,000	30,360,000	43,140,000	55,920,000
12	O&M					
13	Property Taxes	1.5%	3,187,800	6,147,900	8,376,300	10,413,000
14	Annual Revenue Requirement - pre franch		27,791,920	64,097,807	94,431,765	121,869,864
15						
16	Franchise Tax and Comm Fees	2.7%	783,245	1,806,435	2,661,321	3,434,595
17	Annual Revenue Requirement		$ 28,575,165	$ 65,904,243	$ 97,093,086	$ 125,304,459
18	No. of Customers		652,270	652,270	652,270	652,270
19	Rev Req per Cust (i.e., Cost Avoidance)		$ 43.81	$ 101.04	$ 148.85	$ 192.11

20	Deferred Taxes:		1	2	3	4
21	20-year MACRS		3.750%	7.219%	6.677%	6.177%
		Invmt. Yr.				
22	Tax Depreciation	Year 1	8,538,750	16,437,663	15,203,529	14,065,029
23		Year 2		8,538,750	16,437,663	15,203,529
24		Year 3			7,188,750	13,838,823
25		Year 4				7,188,750
26		Year 5				

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27		Year 6				
28		Year 7				
29		Year 8				
30		Year 9				
31		Year 10				
32		Year 11				
33		Year 12				
34		Year 13				
35		Year 14				
36		Year 15				
37		Year 16				
38		Year 17				
39		Year 18				
40		Year 19				
41		Year 20				
42		Sum	8,538,750	24,976,413	38,829,942	50,296,131
43	Book Depreciation		15,180,000	30,360,000	43,140,000	55,920,000
44	Variance		($6,641,250)	($5,383,587)	($4,310,058)	($5,623,869)
45	Deferred Taxes	27.00%	($1,793,403)	($1,453,784)	($1,163,888)	($1,518,670)

	Description	Year 5	Year 6	Year 7	Year 8	Year 9
1	**Rate Base Calculation**					
2	Capex (oregon share @90%)	$ 191,700,000	$ 173,700,000	$ 173,700,000	$ 173,700,000	$ 173,700,000
3	Cumulative Capex	$ 1,030,500,000	$ 1,204,200,000	$ 1,377,900,000	$ 1,551,600,000	$ 1,725,300,000
4	Accumulated Depreciation	(213,300,000)	(293,580,000)	(385,440,000)	(488,880,000)	(603,900,000)
5	Net Plant	$ 817,200,000	$ 910,620,000	$ 992,460,000	$ 1,062,720,000	$ 1,121,400,000
6	Deferred Tax Reserve	8,035,810	10,802,063	14,596,122	19,575,079	25,712,932
7	Year End Rate Base Additions	$ 825,235,810	$ 921,422,063	$ 1,007,056,122	$ 1,082,295,079	$ 1,147,112,932
	Revenue Requirement Calculations					
8	Average Rate Base	$ 762,682,777	$ 873,328,937	$ 964,239,092	$ 1,044,675,601	$ 1,114,704,006
9	Pre-Tax ROR	8.7947%	8.7947%	8.7947%	8.7947%	8.7947%
10	Return and Taxes	$ 67,075,731	$ 76,806,738	$ 84,802,022	$ 91,876,179	$ 98,034,973
11	Book Depreciation	68,700,000	80,280,000	91,860,000	103,440,000	115,020,000
12	O&M					
13	Property Taxes	12,258,000	13,659,300	14,886,900	15,940,800	16,821,000
14	Annual Revenue Requirement - pre franch	148,033,731	170,746,038	191,548,922	211,256,979	229,875,973
15						
16	Franchise Tax and Comm Fees	4,171,958	4,812,047	5,398,324	5,953,746	6,478,475
17	Annual Revenue Requirement	$ 152,205,689	$ 175,558,085	$ 196,947,246	$ 217,210,725	$ 236,354,449
18	No. of Customers	652,270	652,270	652,270	652,270	652,270
19	Rev Req per Cust (i.e., Cost Avoidance)	$ 233.35	$ 269.15	$ 301.94	$ 333.01	$ 362.36
20	Deferred Taxes:	5	6	7	8	9
21	20-year MACRS	5.713%	5.285%	4.888%	4.522%	4.462%
22	Tax Depreciation	13,008,501	12,033,945	11,129,976	10,296,594	10,159,974
23		14,065,029	13,008,501	12,033,945	11,129,976	10,296,594
24		12,799,809	11,841,309	10,951,821	10,131,345	9,370,296
25		13,838,823	12,799,809	11,841,309	10,951,821	10,131,345
26		7,188,750	13,838,823	12,799,809	11,841,309	10,951,821

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27			6,513,750	12,539,403	11,597,949	10,729,449
28				6,513,750	12,539,403	11,597,949
29					6,513,750	12,539,403
30						6,513,750
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42		60,900,912	70,036,137	77,810,013	85,002,147	92,290,581
43	Book Depreciation	68,700,000	80,280,000	91,860,000	103,440,000	115,020,000
44	Variance	($7,799,088)	($10,243,863)	($14,049,987)	($18,437,853)	($22,729,419)
45	Deferred Taxes	($2,106,066)	($2,766,253)	($3,794,058)	($4,978,958)	($6,137,852)

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	Description	Year 10	Year 11	Year 12	Year 13	Year 14
1	**Rate Base Calculation**					
2	Capex (oregon share @90%)	$ 173,700,000	$ 173,700,000	$ 173,700,000	$ 173,700,000	$ 173,700,000
3	Cumulative Capex	$ 1,899,000,000	$ 2,072,700,000	$ 2,246,400,000	$ 2,420,100,000	$ 2,593,800,000
4	Accumulated Depreciation	(730,500,000)	(868,680,000)	(1,018,440,000)	(1,179,780,000)	(1,352,700,000)
5	Net Plant	$ 1,168,500,000	$ 1,204,020,000	$ 1,227,960,000	$ 1,240,320,000	$ 1,241,100,000
6	Deferred Tax Reserve	32,952,159	41,265,510	50,634,205	61,039,937	72,480,305
7	Year End Rate Base Additions	$ 1,201,452,159	$ 1,245,285,510	$ 1,278,594,205	$ 1,301,359,937	$ 1,313,580,305
	Revenue Requirement Calculations					
8	Average Rate Base	$ 1,174,282,545	$ 1,223,368,835	$ 1,261,939,858	$ 1,289,977,071	$ 1,307,470,121
9	Pre-Tax ROR	8.7947%	8.7947%	8.7947%	8.7947%	8.7947%
10	Return and Taxes	$ 103,274,732	$ 107,591,729	$ 110,983,938	$ 113,449,729	$ 114,988,192
11	Book Depreciation	126,600,000	138,180,000	149,760,000	161,340,000	172,920,000
12	O&M					
13	Property Taxes	17,527,500	18,060,300	18,419,400	18,604,800	18,616,500
14	Annual Revenue Requirement - pre franch	247,402,232	263,832,029	279,163,338	293,394,529	306,524,692
15						
16	Franchise Tax and Comm Fees	6,972,409	7,435,441	7,867,516	8,268,586	8,638,627
17	Annual Revenue Requirement	$ 254,374,641	$ 271,267,470	$ 287,030,854	$ 301,663,115	$ 315,163,319
18	No. of Customers	652,270	652,270	652,270	652,270	652,270
19	Rev Req per Cust (i.e., Cost Avoidance)	$ 389.98	$ 415.88	$ 440.05	$ 462.48	$ 483.18
20	Deferred Taxes:	10	11	12	13	14
21	20-year MACRS	4.461%	4.462%	4.461%	4.462%	4.461%
22	Tax Depreciation	10,157,697	10,159,974	10,157,697	10,159,974	10,157,697
23		10,159,974	10,157,697	10,159,974	10,157,697	10,159,974
24		8,668,674	8,553,654	8,551,737	8,553,654	8,551,737
25		9,370,296	8,668,674	8,553,654	8,551,737	8,553,654
26		10,131,345	9,370,296	8,668,674	8,553,654	8,551,737

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27		9,923,481	9,180,045	8,490,456	7,854,714	7,750,494
28		10,729,449	9,923,481	9,180,045	8,490,456	7,854,714
29		11,597,949	10,729,449	9,923,481	9,180,045	8,490,456
30		12,539,403	11,597,949	10,729,449	9,923,481	9,180,045
31		6,513,750	12,539,403	11,597,949	10,729,449	9,923,481
32			6,513,750	12,539,403	11,597,949	10,729,449
33				6,513,750	12,539,403	11,597,949
34					6,513,750	12,539,403
35						6,513,750
36						
37						
38						
39						
40						
41						
42		99,792,018	107,394,372	115,066,269	122,805,963	130,554,540
43	Book Depreciation	126,600,000	138,180,000	149,760,000	161,340,000	172,920,000
44	Variance	($26,807,982)	($30,785,628)	($34,693,731)	($38,534,037)	($42,365,460)
45	Deferred Taxes	($7,239,227)	($8,313,351)	($9,368,695)	($10,405,731)	($11,440,369)

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	Description	Year 15	Year 16	Year 17	Year 18	Year 19
1	**Rate Base Calculation**					
2	Capex (oregon share @90%)	$ 173,700,000	$ 173,700,000	$ 173,700,000	$ 173,700,000	$ 173,700,000
3	Cumulative Capex	$ 2,767,500,000	$ 2,941,200,000	$ 3,114,900,000	$ 3,288,600,000	$ 3,462,300,000
4	Accumulated Depreciation	(1,537,200,000)	(1,733,280,000)	(1,940,940,000)	(2,160,180,000)	(2,391,000,000)
5	Net Plant	$ 1,230,300,000	$ 1,207,920,000	$ 1,173,960,000	$ 1,128,420,000	$ 1,071,300,000
6	Deferred Tax Reserve	84,954,745	98,463,823	113,006,972	128,584,758	145,196,615
7	Year End Rate Base Additions	$ 1,315,254,745	$ 1,306,383,823	$ 1,286,966,972	$ 1,257,004,758	$ 1,216,496,615
	Revenue Requirement Calculations					
8	Average Rate Base	$ 1,314,417,525	$ 1,310,819,284	$ 1,296,675,397	$ 1,271,985,865	$ 1,236,750,686
9	Pre-Tax ROR	8.7947%	8.7947%	8.7947%	8.7947%	8.7947%
10	Return and Taxes	$ 115,599,196	$ 115,282,741	$ 114,038,827	$ 111,867,455	$ 108,768,624
11	Book Depreciation	184,500,000	196,080,000	207,660,000	219,240,000	230,820,000
12	O&M					
13	Property Taxes	18,454,500	18,118,800	17,609,400	16,926,300	16,069,500
14	Annual Revenue Requirement - pre franch	318,553,696	329,481,541	339,308,227	348,033,755	355,658,124
15						
16	Franchise Tax and Comm Fees	8,977,634	9,285,608	9,562,548	9,808,455	10,023,329
17	Annual Revenue Requirement	$ 327,531,330	$ 338,767,149	$ 348,870,775	$ 357,842,210	$ 365,681,452
18	No. of Customers	652,270	652,270	652,270	652,270	652,270
19	Rev Req per Cust (i.e., Cost Avoidance)	$ 502.14	$ 519.37	$ 534.86	$ 548.61	$ 560.63
20	Deferred Taxes:	15	16	17	18	19
21	20-year MACRS	4.462%	4.461%	4.462%	4.461%	4.462%
22	Tax Depreciation	10,159,974	10,157,697	10,159,974	10,157,697	10,159,974
23		10,157,697	10,159,974	10,157,697	10,159,974	10,157,697
24		8,553,654	8,551,737	8,553,654	8,551,737	8,553,654
25		8,551,737	8,553,654	8,551,737	8,553,654	8,551,737
26		8,553,654	8,551,737	8,553,654	8,551,737	8,553,654

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27		7,748,757	7,750,494	7,748,757	7,750,494	7,748,757
28		7,750,494	7,748,757	7,750,494	7,748,757	7,750,494
29		7,854,714	7,750,494	7,748,757	7,750,494	7,748,757
30		8,490,456	7,854,714	7,750,494	7,748,757	7,750,494
31		9,180,045	8,490,456	7,854,714	7,750,494	7,748,757
32		9,923,481	9,180,045	8,490,456	7,854,714	7,750,494
33		10,729,449	9,923,481	9,180,045	8,490,456	7,854,714
34		11,597,949	10,729,449	9,923,481	9,180,045	8,490,456
35		12,539,403	11,597,949	10,729,449	9,923,481	9,180,045
36		6,513,750	12,539,403	11,597,949	10,729,449	9,923,481
37			6,513,750	12,539,403	11,597,949	10,729,449
38				6,513,750	12,539,403	11,597,949
39					6,513,750	12,539,403
40						6,513,750
41						
42		138,305,214	146,053,791	153,804,465	161,553,042	169,303,716
43	Book Depreciation	184,500,000	196,080,000	207,660,000	219,240,000	230,820,000
44	Variance	($46,194,786)	($50,026,209)	($53,855,535)	($57,686,958)	($61,516,284)
45	Deferred Taxes	($12,474,440)	($13,509,077)	($14,543,149)	($15,577,786)	($16,611,857)

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	Description	Year 20	Year 21	Year 22	Year 23	Year 24
1	**Rate Base Calculation**					
2	Capex (oregon share @90%)	$ 173,700,000	$ 173,700,000	$ 173,700,000	$ 173,700,000	$ 173,700,000
3	Cumulative Capex	$ 3,636,000,000	$ 3,809,700,000	$ 3,983,400,000	$ 4,157,100,000	$ 4,330,800,000
4	Accumulated Depreciation	(2,633,400,000)	(2,887,380,000)	(3,152,940,000)	(3,430,080,000)	(3,718,800,000)
5	Net Plant	$ 1,002,600,000	$ 922,320,000	$ 830,460,000	$ 727,020,000	$ 612,000,000
6	Deferred Tax Reserve	162,843,110	184,654,449	213,629,550	249,297,346	291,206,472
7	Year End Rate Base Additions	$ 1,165,443,110	$ 1,106,974,449	$ 1,044,089,550	$ 976,317,346	$ 903,206,472
	Revenue Requirement Calculations					
8	Average Rate Base	$ 1,190,969,863	$ 1,136,208,779	$ 1,075,531,999	$ 1,010,203,448	$ 939,761,909
9	Pre-Tax ROR	8.7947%	8.7947%	8.7947%	8.7947%	8.7947%
10	Return and Taxes	$ 104,742,333	$ 99,926,255	$ 94,589,909	$ 88,844,453	$ 82,649,325
11	Book Depreciation	242,400,000	253,980,000	265,560,000	277,140,000	288,720,000
12	O&M					
13	Property Taxes	15,039,000	13,834,800	12,456,900	10,905,300	9,180,000
14	Annual Revenue Requirement - pre franch	362,181,333	367,741,055	372,606,809	376,889,753	380,549,325
15						
16	Franchise Tax and Comm Fees	10,207,169	10,363,856	10,500,985	10,621,689	10,724,824
17	Annual Revenue Requirement	$ 372,388,502	$ 378,104,911	$ 383,107,794	$ 387,511,442	$ 391,274,149
18	No. of Customers	652,270	652,270	652,270	652,270	652,270
19	Rev Req per Cust (i.e., Cost Avoidance)	$ 570.91	$ 579.68	$ 587.35	$ 594.10	$ 599.87
20	Deferred Taxes:	20	21	22	23	24
21	20-year MACRS	4.461%	2.231%	0.000%	0.000%	0.000%
22	Tax Depreciation	10,157,697	5,079,987	-	-	-
23		10,159,974	10,157,697	5,079,987	-	-
24		8,551,737	8,553,654	8,551,737	4,276,827	-
25		8,553,654	8,551,737	8,553,654	8,551,737	4,276,827
26		8,551,737	8,553,654	8,551,737	8,553,654	8,551,737

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27		7,750,494	7,748,757	7,750,494	7,748,757	7,750,494
28		7,748,757	7,750,494	7,748,757	7,750,494	7,748,757
29		7,750,494	7,748,757	7,750,494	7,748,757	7,750,494
30		7,748,757	7,750,494	7,748,757	7,750,494	7,748,757
31		7,750,494	7,748,757	7,750,494	7,748,757	7,750,494
32		7,748,757	7,750,494	7,748,757	7,750,494	7,748,757
33		7,750,494	7,748,757	7,750,494	7,748,757	7,750,494
34		7,854,714	7,750,494	7,748,757	7,750,494	7,748,757
35		8,490,456	7,854,714	7,750,494	7,748,757	7,750,494
36		9,180,045	8,490,456	7,854,714	7,750,494	7,748,757
37		9,923,481	9,180,045	8,490,456	7,854,714	7,750,494
38		10,729,449	9,923,481	9,180,045	8,490,456	7,854,714
39		11,597,949	10,729,449	9,923,481	9,180,045	8,490,456
40		12,539,403	11,597,949	10,729,449	9,923,481	9,180,045
41		6,513,750	12,539,403	11,597,949	10,729,449	9,923,481
42		177,052,293	173,209,230	158,260,707	145,056,618	133,524,009
43	Book Depreciation	242,400,000	253,980,000	265,560,000	277,140,000	288,720,000
44	Variance	($65,347,707)	($80,770,770)	($107,299,293)	($132,083,382)	($155,195,991)
45	Deferred Taxes	($17,646,495)	($21,811,339)	($28,975,101)	($35,667,796)	($41,909,125)

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	Description	Year 25
1	**Rate Base Calculation**	
2	Capex (oregon share @90%)	$ 173,700,000
3	Cumulative Capex	$ 4,504,500,000
4	Accumulated Depreciation	(4,019,100,000)
5	Net Plant	$ 485,400,000
6	Deferred Tax Reserve	339,139,234
7	Year End Rate Base Additions	$ 824,539,234
	Revenue Requirement Calculations	
8	Average Rate Base	$ 863,872,853
9	Pre-Tax ROR	8.7947%
10	Return and Taxes	$ 75,975,103
11	Book Depreciation	300,300,000
12	O&M	
13	Property Taxes	7,281,000
14	Annual Revenue Requirement - pre franch	383,556,103
15		
16	Franchise Tax and Comm Fees	10,809,563
17	Annual Revenue Requirement	$ 394,365,666
18	No. of Customers	652,270
19	Rev Req per Cust (i.e., Cost Avoidance)	$ 604.61
20	Deferred Taxes:	25
21	20-year MACRS	0.000%
22	Tax Depreciation	-
23		-
24		-
25		-
26		4,276,827

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27		7,748,757
28		7,750,494
29		7,748,757
30		7,750,494
31		7,748,757
32		7,750,494
33		7,748,757
34		7,750,494
35		7,748,757
36		7,750,494
37		7,748,757
38		7,750,494
39		7,854,714
40		8,490,456
41		9,180,045
42		122,797,548
43	Book Depreciation	300,300,000
44	Variance	($177,502,452)
45	Deferred Taxes	($47,932,762)

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1	**General Inputs:**		
2	Start Date:	11/1/2024	<-- *input*
3	Year 1:	2025	<-- *input*
4	UPC Therms - New Customers	1000	<-- *input*
5	NPV Number of Years:	15	<-- *input*
6	Model depreciation assumption	6.67%	
7	**Distribution Revenue Calculation:**		
8	UPC (therms)	1000	
9			
10	Customer Charge	**$10.00**	<-- *input (tariff)*
11	Rate per Therm	0.90649	<-- *input (tariff)*
12	**Annual Distribution Revenue (Real $)**	**$1,026.49**	
13	**NPV**	$0	
14			
15	**Construction Costs**	**($4,419)**	***Goal seek to produce 0 NPV***
16	**Times Margin**	-4.3	

UPC (Therms)
LEA
Times Margin

17	**Cost of Capital**				
18				**Weighted**	**After-tax**
19		**% of Capital**	**Cost**	**Cost**	**Cost**
20					
21	**Debt**	50.00%	4.712%	2.356%	1.720%
22	**Common Equity**	50.00%	9.400%	4.700%	4.700%
23		100.00%		**7.056%**	**6.420%**

24	**Other Costs:**		
25	**State Tax Rate**	7.60%	<-- *input*
26	**Federal Tax Rate**	21.00%	<-- *input*
27	**Revenue Sensitive Rate (Franchise tax, Comm fee)**	2.741%	<-- *input*
28	**Property Tax Rate**	1.50%	<-- *input*
29	**Incremental O&M**	79.19	<-- *input*

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Model Results at Proposed Consumption Levels (Therms)			
250	450	650	1,000
-$144	-$1,284	-$2,424	-$4,419
-0.4	-2.4	-3.4	-4.3

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Growth Rate
2022-24 CCI Cap
2025-27 CCI Cap
Beyond 2027

		Source		2024
1	**Normalized Load**	NWN internal data		1,088,444,642
2	**Non-Combustion Exclusion**	NWN internal data		20,733,841
3	**RNG**	NWN internal data		11,540,147
4	**MT CO2e**	NWN internal data		5,609,893
5	**Compliance Curve (MT CO2e)**	NWN internal data		5,316,897
6	**Over (Under) Compliance**			292,996
7	**CCI Cap**			560,989
8	**Over (Under) CCI Cap**			(267,994)
9	**Accumulated Over (Under) CCI Cap**			(267,994)
10	**New Customer Therms**	NWN internal data		450
11	**New Customer MT CO2e**	NWN internal data		2.39
12	**CPP Proxy Cost of New Customer**	NWN internal data - Revised	$	150.65
13	**CPP Proxy Cost per Therm**		$	0.33
14	**CPP Proxy Cost**		$	334.78
15	**2022 CPP Annual Cap (MT CO2e)**	DEQ Greenhouse Gas Emissions Calculations to supplement rulemaking GHGCR2021, Calculation for proposed OAR 340-271-9000 Table 2: Oregon Climate Protection Program Caps		28,081,335
16	**CPP Annual Caps (MT CO2e)**	DEQ Greenhouse Gas Emissions Calculations to supplement rulemaking GHGCR2021, Calculation for proposed OAR 340-271-9000 Table 2: Oregon Climate Protection Program Caps		25,921,232
17	**CPP Revenue Multiplier**			-7.69%
18	**CPP Revenue**		$	25.75

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0.15%
10.00%
15.00%
20.00%

		2025	2026	2027	2028
1	Normalized Load	1,090,264,509	1,091,897,976	1,093,353,861	1,094,995,193
2	Non-Combustion Exclusion	20,733,841	20,733,841	20,733,841	20,733,841
3	RNG	11,540,147	11,540,147	11,540,147	11,540,147
4	MT CO2e	5,619,559	5,628,235	5,635,968	5,644,686
5	Compliance Curve (MT CO2e)	5,095,359	4,873,822	4,652,285	4,430,747
6	Over (Under) Compliance	524,200	754,413	983,683	1,213,939
7	CCI Cap	842,934	844,235	845,395	1,128,937
8	Over (Under) CCI Cap	(318,734)	(89,822)	138,288	85,002
9	Accumulated Over (Under) CCI Cap	(586,728)	(676,550)	(538,263)	(453,261)
10	New Customer Therms	450	450	450	450
11	New Customer MT CO2e	2.39	2.39	2.39	2.39
12	CPP Proxy Cost of New Customer	$ 150.65	$ 150.65	$ 990.00	$ 990.00
13	CPP Proxy Cost per Therm	$ 0.33	$ 0.33	$ 2.20	$ 2.20
14	CPP Proxy Cost	$ 334.78	$ 334.78	$ 2,200.00	$ 2,200.00
15	2022 CPP Annual Cap (MT CO2e)				
16	CPP Annual Caps (MT CO2e)	25,763,209	24,637,057	23,510,904	23,013,190
17	CPP Revenue Multiplier	-8.26%	-12.27%	-16.28%	-18.05%
18	CPP Revenue	$ 27.64	$ 41.06	$ 358.07	$ 397.06

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		2029	2030	2031	2032
1	Normalized Load	1,096,638,989	1,098,285,253	1,099,933,988	1,101,585,198
2	Non-Combustion Exclusion	20,733,841	20,733,841	20,733,841	20,733,841
3	RNG	11,540,147	11,540,147	11,540,147	11,540,147
4	MT CO2e	5,653,417	5,662,161	5,670,918	5,679,688
5	Compliance Curve (MT CO2e)	4,209,210	3,987,673	3,766,135	3,544,598
6	Over (Under) Compliance	1,444,207	1,674,488	1,904,783	2,135,090
7	CCI Cap	1,130,683	1,132,432	1,134,184	1,135,938
8	Over (Under) CCI Cap	313,523	542,056	770,599	999,153
9	Accumulated Over (Under) CCI Cap	(139,738)	402,318	1,172,917	2,172,070
10	New Customer Therms	450	450	450	450
11	New Customer MT CO2e	2.39	2.39	2.39	2.39
12	CPP Proxy Cost of New Customer	$ 990.00	$ 990.00	$ 990.00	$ 990.00
13	CPP Proxy Cost per Therm	$ 2.20	$ 2.20	$ 2.20	$ 2.20
14	CPP Proxy Cost	$ 2,200.00	$ 2,200.00	$ 2,200.00	$ 2,200.00
15	2022 CPP Annual Cap (MT CO2e)				
16	CPP Annual Caps (MT CO2e)	21,842,149	20,671,108	19,910,424	18,688,088
17	CPP Revenue Multiplier	-22.22%	-26.39%	-29.10%	-33.45%
18	CPP Revenue	$ 488.80	$ 580.55	$ 640.14	$ 735.90

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		2033	2034	2035	2036
1	Normalized Load	1,103,238,887	1,104,895,059	1,106,553,717	1,108,214,864
2	Non-Combustion Exclusion	20,733,841	20,733,841	20,733,841	20,733,841
3	RNG	11,540,147	11,540,147	11,540,147	11,540,147
4	MT CO2e	5,688,472	5,697,269	5,706,079	5,714,902
5	Compliance Curve (MT CO2e)	3,323,061	3,101,523	2,879,986	2,726,387
6	Over (Under) Compliance	2,365,411	2,595,746	2,826,093	2,988,515
7	CCI Cap	1,137,694	1,139,454	1,141,216	1,142,980
8	Over (Under) CCI Cap	1,227,717	1,456,292	1,684,877	1,845,534
9	Accumulated Over (Under) CCI Cap	3,399,786	4,856,078	6,540,955	8,386,490
10	New Customer Therms	450	450	450	450
11	New Customer MT CO2e	2.39	2.39	2.39	2.39
12	CPP Proxy Cost of New Customer	$ 990.00	$ 990.00	$ 990.00	$ 990.00
13	CPP Proxy Cost per Therm	$ 2.20	$ 2.20	$ 2.20	$ 2.20
14	CPP Proxy Cost	$ 2,200.00	$ 2,200.00	$ 2,200.00	$ 2,200.00
15	2022 CPP Annual Cap (MT CO2e)				
16	CPP Annual Caps (MT CO2e)	17,465,752	16,243,416	15,021,080	14,219,956
17	CPP Revenue Multiplier	-37.80%	-42.16%	-46.51%	-49.36%
18	CPP Revenue	$ 831.67	$ 927.43	$ 1,023.19	$ 1,085.95

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		2037	2038	2039	2040
1	Normalized Load	1,109,878,506	1,111,544,645	1,113,213,285	1,114,884,430
2	Non-Combustion Exclusion	20,733,841	20,733,841	20,733,841	20,733,841
3	RNG	11,540,147	11,540,147	11,540,147	11,540,147
4	MT CO2e	5,723,738	5,732,588	5,741,451	5,750,327
5	Compliance Curve (MT CO2e)	2,572,787	2,419,188	2,265,589	2,111,990
6	Over (Under) Compliance	3,150,951	3,313,400	3,475,862	3,638,337
7	CCI Cap	1,144,748	1,146,518	1,148,290	1,150,065
8	Over (Under) CCI Cap	2,006,203	2,166,882	2,327,572	2,488,272
9	Accumulated Over (Under) CCI Cap	10,392,693	12,559,575	14,887,147	17,375,418
10	New Customer Therms	450	450	450	450
11	New Customer MT CO2e	2.39	2.39	2.39	2.39
12	CPP Proxy Cost of New Customer	$ 990.00	$ 990.00	$ 990.00	$ 990.00
13	CPP Proxy Cost per Therm	$ 2.20	$ 2.20	$ 2.20	$ 2.20
14	CPP Proxy Cost	$ 2,200.00	$ 2,200.00	$ 2,200.00	$ 2,200.00
15	2022 CPP Annual Cap (MT CO2e)				
16	CPP Annual Caps (MT CO2e)	13,418,831	12,617,707	11,816,583	11,015,459
17	CPP Revenue Multiplier	-52.21%	-55.07%	-57.92%	-60.77%
18	CPP Revenue	$ 1,148.72	$ 1,211.48	$ 1,274.24	$ 1,337.01

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		2041	2042	2043	2044
1	Normalized Load	1,116,558,083	1,118,234,249	1,119,912,932	1,121,594,134
2	Non-Combustion Exclusion	20,733,841	20,733,841	20,733,841	20,733,841
3	RNG	11,540,147	11,540,147	11,540,147	11,540,147
4	MT CO2e	5,759,217	5,768,119	5,777,036	5,785,965
5	Compliance Curve (MT CO2e)	1,958,390	1,804,791	1,651,192	1,497,593
6	Over (Under) Compliance	3,800,827	3,963,328	4,125,844	4,288,372
7	CCI Cap	1,151,843	1,153,624	1,155,407	1,157,193
8	Over (Under) CCI Cap	2,648,983	2,809,705	2,970,437	3,131,179
9	Accumulated Over (Under) CCI Cap	20,024,402	22,834,106	25,804,543	28,935,722
10	New Customer Therms	450	450	450	450
11	New Customer MT CO2e	2.39	2.39	2.39	2.39
12	CPP Proxy Cost of New Customer	$ 990.00	$ 990.00	$ 990.00	$ 990.00
13	CPP Proxy Cost per Therm	$ 2.20	$ 2.20	$ 2.20	$ 2.20
14	CPP Proxy Cost	$ 2,200.00	$ 2,200.00	$ 2,200.00	$ 2,200.00
15	2022 CPP Annual Cap (MT CO2e)				
16	CPP Annual Caps (MT CO2e)	10,214,334	9,413,210	8,612,086	7,810,962
17	CPP Revenue Multiplier	-63.63%	-66.48%	-69.33%	-72.18%
18	CPP Revenue	$ 1,399.77	$ 1,462.53	$ 1,525.30	$ 1,588.06

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		2045	2046	2047	2048	2049
1	**Normalized Load**					
2	**Non-Combustion Exclusion**					
3	**RNG**					
4	**MT CO2e**					
5	**Compliance Curve (MT CO2e)**					
6	**Over (Under) Compliance**					
7	**CCI Cap**					
8	**Over (Under) CCI Cap**					
9	**Accumulated Over (Under) CCI Cap**					
10	**New Customer Therms**	450	450	450	450	450
11	**New Customer MT CO2e**	2.39	2.39	2.39	2.39	2.39
12	**CPP Proxy Cost of New Customer**	$ 990.00	$ 990.00	$ 990.00	$ 990.00	$ 990.00
13	**CPP Proxy Cost per Therm**	$ 2.20	$ 2.20	$ 2.20	$ 2.20	$ 2.20
14	**CPP Proxy Cost**	$ 2,200.00	$ 2,200.00	$ 2,200.00	$ 2,200.00	$ 2,200.00
15	**2022 CPP Annual Cap (MT CO2e)**					
16	**CPP Annual Caps (MT CO2e)**	7,009,837	6,208,713	5,407,589	4,606,465	3,805,340
17	**CPP Revenue Multiplier**	-75.04%	-77.89%	-80.74%	-83.60%	-86.45%
18	**CPP Revenue**	$ 1,650.82	$ 1,713.59	$ 1,776.35	$ 1,839.11	$ 1,901.87

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LEA Determined ($4,419)

			Year 1	Year 2	Year 3	Year 4	Year 5
1	**Depreciation (using book depreciation rates)**	6.67%	(295)	(295)	(295)	(295)	(295)
2	**O&M**		79	79	79	79	79
3	**Property Taxes**		(64)	(59)	(55)	(51)	(46)
	Taxes on Equity Return						
4	**State**		(21)	(20)	(18)	(17)	(15)
5	**Federal**		(54)	(50)	(46)	(43)	(39)
6	**Total Taxes**		(75)	(70)	(65)	(59)	(54)
	Return on Rate Base						
7	**Debt**		(101)	(94)	(87)	(81)	(74)
8	**Common Equity**		(202)	(188)	(174)	(161)	(147)
9	**Total Return**		(303)	(283)	(262)	(241)	(221)
10	**Subtotal Cost of Service**		(656)	(627)	(597)	(567)	(537)
11	**Revenue Sensitive Items**		(18)	(18)	(17)	(16)	(15)
12	**Total Cost of Service**		-675	-645	-614	-583	-552
13	**Cost of Proxy CPP ($/Therm)**		0.33	0.33	3.00	3.00	3.00
14	**UPC (Therms)**		1,000	1,000	1,000	1,000	1,000
15	**New Customer Proxy Cost of CPP**		335	335	3,000	3,000	3,000
16	**Less: New Customer Recovery of CPP (re class WACOD)**		-28	-41	-488	-541	-667
17	**Nominal Change in Base Rate Revenue per Customer (Rate Base)**		0	22	44	66	88
18	**Less: Contribution to New Non-Growth Capex**		-44	-101	-149	-192	-233
19	**Total Cost of Service (Net)**		-412	-430	1,793	1,750	1,636
20	**New Customer Revenue**		$1,026	$1,026	$1,026	$1,026	$1,026
21	**Revenue less cost of service (impact on existing customers)**		$1,438	$1,457	($767)	($724)	($610)

			Year 6	Year 7	Year 8	Year 9	Year 10
1	Depreciation (using book depreciation rates)	6.67%	(295)	(295)	(295)	(295)	(295)
2	O&M		79	79	79	79	79
3	Property Taxes		(42)	(37)	(33)	(28)	(24)
	Taxes on Equity Return						
4	State		(14)	(13)	(11)	(10)	(9)
5	Federal		(36)	(32)	(29)	(25)	(22)
6	Total Taxes		(50)	(45)	(40)	(35)	(31)
	Return on Rate Base						
7	Debt		(67)	(61)	(54)	(48)	(42)
8	Common Equity		(134)	(121)	(108)	(96)	(83)
9	Total Return		(201)	(182)	(163)	(144)	(125)
10	Subtotal Cost of Service		(508)	(479)	(451)	(423)	(395)
11	Revenue Sensitive Items		(14)	(14)	(13)	(12)	(11)
12	Total Cost of Service		-522	-493	-464	-435	-406
13	Cost of Proxy CPP ($/Therm)		3.00	3.00	3.00	3.00	3.00
14	UPC (Therms)		1,000	1,000	1,000	1,000	1,000
15	New Customer Proxy Cost of CPP		3,000	3,000	3,000	3,000	3,000
16	Less: New Customer Recovery of CPP (re class WACOD)		-792	-873	-1,004	-1,134	-1,265
17	Nominal Change in Base Rate Revenue per Customer (Rate Base)		110	132	155	177	199
18	Less: Contribution to New Non-Growth Capex		-269	-302	-333	-362	-390
19	Total Cost of Service (Net)		1,527	1,465	1,354	1,245	1,138
20	New Customer Revenue		$1,026	$1,026	$1,026	$1,026	$1,026
21	Revenue less cost of service (impact on existing customers)		($501)	($438)	($328)	($219)	($111)

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			Year 11	Year 12	Year 13	Year 14	Year 15
1	Depreciation (using book depreciation rates)	6.67%	(295)	(295)	(295)	(295)	(295)
2	O&M		79	79	79	79	79
3	Property Taxes		(20)	(15)	(11)	(6)	(2)
	Taxes on Equity Return						
4	State		(7)	(6)	(5)	(3)	(2)
5	Federal		(19)	(15)	(12)	(9)	(5)
6	Total Taxes		(26)	(21)	(17)	(12)	(7)
	Return on Rate Base						
7	Debt		(35)	(29)	(23)	(16)	(10)
8	Common Equity		(71)	(58)	(45)	(33)	(20)
9	Total Return		(106)	(87)	(68)	(49)	(30)
10	Subtotal Cost of Service		(367)	(339)	(311)	(283)	(255)
11	Revenue Sensitive Items		(10)	(10)	(9)	(8)	(7)
12	Total Cost of Service		-377	-348	-320	-291	-262
13	Cost of Proxy CPP ($/Therm)		3.00	3.00	3.00	3.00	3.00
14	UPC (Therms)		1,000	1,000	1,000	1,000	1,000
15	New Customer Proxy Cost of CPP		3,000	3,000	3,000	3,000	3,000
16	Less: New Customer Recovery of CPP (re class WACOD)		-1,395	-1,481	-1,566	-1,652	-1,738
17	Nominal Change in Base Rate Revenue per Customer (Rate Base)		221	243	265	287	309
18	Less: Contribution to New Non-Growth Capex		-416	-440	-462	-483	-502
19	Total Cost of Service (Net)		1,032	973	916	861	807
20	New Customer Revenue		$1,026	$1,026	$1,026	$1,026	$1,026
21	Revenue less cost of service (impact on existing customers)		($6)	$53	$110	$166	$219

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			Year 16	Year 17	Year 18	Year 19	Year 20
1	Depreciation (using book depreciation rates)	6.67%	(295)	(295)	(295)	(295)	(295)
2	O&M		79	79	79	79	79
3	Property Taxes		2	7	11	16	20
	Taxes on Equity Return						
4	State		(1)	1	2	3	4
5	Federal		(2)	1	5	8	11
6	Total Taxes		(3)	2	7	11	16
	Return on Rate Base						
7	Debt		(4)	3	9	15	22
8	Common Equity		(7)	5	18	30	43
9	Total Return		(11)	8	27	46	65
10	Subtotal Cost of Service		(227)	(199)	(171)	(143)	(115)
11	Revenue Sensitive Items		(6)	(6)	(5)	(4)	(3)
12	Total Cost of Service		-233	-204	-176	-147	-118
13	Cost of Proxy CPP ($/Therm)		3.00	3.00	3.00	3.00	3.00
14	UPC (Therms)		1,000	1,000	1,000	1,000	1,000
15	New Customer Proxy Cost of CPP		3,000	3,000	3,000	3,000	3,000
16	Less: New Customer Recovery of CPP (re class WACOD)		-1,823	-1,909	-1,994	-2,080	-2,166
17	Nominal Change in Base Rate Revenue per Customer (Rate Base)		585	585	585	585	585
18	Less: Contribution to New Non-Growth Capex		-519	-535	-549	-561	-571
19	Total Cost of Service (Net)		1,009	937	866	797	730
20	New Customer Revenue		$1,026	$1,026	$1,026	$1,026	$1,026
21	Revenue less cost of service (impact on existing customers)		$18	$90	$160	$229	$296

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			Year 21	Year 22	Year 23	Year 24	Year 25
1	Depreciation (using book depreciation rates)	6.67%	(295)	(295)	(295)	(295)	(295)
2	O&M		79	79	79	79	79
3	Property Taxes		25	29	33	38	42
	Taxes on Equity Return						
4	State		6	7	8	9	10
5	Federal		15	17	20	23	26
6	Total Taxes		20	24	28	32	36
	Return on Rate Base						
7	Debt		28	33	38	43	48
8	Common Equity		55	66	76	86	96
9	Total Return		83	99	114	129	144
10	Subtotal Cost of Service		(88)	(63)	(40)	(17)	7
11	Revenue Sensitive Items		(2)	(2)	(1)	(0)	0
12	Total Cost of Service		-90	-65	-41	-17	7
13	Cost of Proxy CPP ($/Therm)		3.00	3.00	3.00	3.00	3.00
14	UPC (Therms)		1,000	1,000	1,000	1,000	1,000
15	New Customer Proxy Cost of CPP		3,000	3,000	3,000	3,000	3,000
16	Less: New Customer Recovery of CPP (re class WACOD)		-2,251	-2,337	-2,422	-2,508	-2,593
17	Nominal Change in Base Rate Revenue per Customer (Rate Base)		585	585	585	585	585
18	Less: Contribution to New Non-Growth Capex		-580	-587	-594	-600	-605
19	Total Cost of Service (Net)		663	595	527	460	393
20	New Customer Revenue		$1,026	$1,026	$1,026	$1,026	$1,026
21	Revenue less cost of service (impact on existing customers)		$363	$431	$500	$567	$633

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Income Statement			Year 1	Year 2	Year 3	Year 4
1	Revenue		1,026	1,026	1,026	1,026
2	CPP Revenue		28	41	488	541
3	CPP Cost		(335)	(335)	(3,000)	(3,000)
4	Nominal Change in Base Rate Revenue per Customer		0	(22)	(44)	(66)
5	Contribution to New Non-Growth Capex		44	101	149	192
6	Operations & Maintenance	$79.19	(79)	(79)	(79)	(79)
7	Depreciation (model assumed term)	6.67%	295	0	0	0
8	Franchise Tax	2.74%	(28)	(28)	(28)	(28)
9	Property Tax	1.50%	66	62	62	62
10	Interest Expense	4.71%	(101)	(97)	(95)	(93)
11	Net Income Before Tax		916	669	(1,521)	(1,445)
12	Income Tax	27.00%	247	181	(411)	(390)
13	Net Available to Common		668	489	(1,110)	(1,055)

Balance Sheet			Year 1	Year 2	Year 3	Year 4
Assets						
1	Gross Plant		(4,419)	(4,419)	(4,419)	(4,419)
2	Accumulated Depreciation		(295)	(295)	(295)	(295)
3	Net Plant		(4,124)	(4,124)	(4,124)	(4,124)
4	Total Assets		(4,124)	(4,124)	(4,124)	(4,124)
Liabilities and Equity						
5	Common Equity		(2,080)	(2,036)	(1,997)	(1,960)
6	Long Term Debt		(2,080)	(2,036)	(1,997)	(1,960)
7	Deferred Taxes		35	(51)	(131)	(205)
8	Total Liabilities and Equity		(4,124)	(4,124)	(4,124)	(4,124)

Cash Flow Statement			Year 1	Year 2	Year 3	Year 4

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Operating Activities					
1	**Net Income**	668	489	(1,110)	(1,055)
2	**Depreciation**	(295)	0	0	0
3	**Deferred Taxes**	35	(86)	(80)	(74)
4	**Cash Provided by Operating Activities**	409	402	(1,190)	(1,128)
Investing Activities					
5	**Project**	4,419	0	0	0
6	**Cash Used in Investing Activities**	4,419	0	0	0
Financing Activities					
7	**Common Stock Issued**	(2,209)	0	0	0
8	**Long Term Debt Issued**	(2,209)	0	0	0
9	**Long Term Debt Retired**	130	43	40	37
10	**Common Stock Dividends**	(538)	(445)	1,150	1,092
11	**Cash Provided by Financing Activities**	(4,828)	(402)	1,190	1,128
12	**Net Cash Flow**	0	0	0	0

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Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16
1,026	1,026	1,026	1,026	1,026	1,026	1,026	1,026	1,026	1,026	1,026	1,026
667	792	873	1,004	1,134	1,265	1,395	1,481	1,566	1,652	1,738	1,823
(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)
(88)	(110)	(132)	(155)	(177)	(199)	(221)	(243)	(265)	(287)	(309)	(585)
233	269	302	333	362	390	416	440	462	483	502	519
(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)
0	0	0	0	0	0	0	0	0	0	0	0
(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)
62	62	62	62	62	62	62	62	62	62	62	62
(92)	(90)	(89)	(87)	(86)	(85)	(83)	(82)	(81)	(80)	(78)	(77)
(1,299)	(1,159)	(1,065)	(924)	(785)	(648)	(512)	(423)	(336)	(250)	(167)	(338)
(351)	(313)	(288)	(250)	(212)	(175)	(138)	(114)	(91)	(68)	(45)	(91)
(948)	(846)	(777)	(675)	(573)	(473)	(374)	(309)	(245)	(183)	(122)	(247)

Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16
(4,419)	(4,419)	(4,419)	(4,419)	(4,419)	(4,419)	(4,419)	(4,419)	(4,419)	(4,419)	(4,419)	(4,419)
(295)	(295)	(295)	(295)	(295)	(295)	(295)	(295)	(295)	(295)	(295)	(295)
(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)
(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)
(1,926)	(1,894)	(1,865)	(1,838)	(1,811)	(1,785)	(1,758)	(1,732)	(1,705)	(1,678)	(1,652)	(1,625)
(1,926)	(1,894)	(1,865)	(1,838)	(1,811)	(1,785)	(1,758)	(1,732)	(1,705)	(1,678)	(1,652)	(1,625)
(273)	(336)	(394)	(448)	(501)	(555)	(608)	(661)	(714)	(768)	(821)	(874)
(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)

Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16

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(948)	(846)	(777)	(675)	(573)	(473)	(374)	(309)	(245)	(183)	(122)	(247)
0	0	0	0	0	0	0	0	0	0	0	0
(68)	(63)	(58)	(54)	(53)	(53)	(53)	(53)	(53)	(53)	(53)	(53)
(1,016)	(909)	(836)	(729)	(626)	(526)	(427)	(362)	(298)	(236)	(175)	(300)
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
34	32	29	27	27	27	27	27	27	27	27	27
982	877	807	702	600	499	400	335	272	209	148	274
1,016	909	836	729	626	526	427	362	298	236	175	300
0	0	0	0	0	0	0	0	0	0	0	0

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Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25
1,026	1,026	1,026	1,026	1,026	1,026	1,026	1,026	1,026
1,909	1,994	2,080	2,166	2,251	2,337	2,422	2,508	2,593
(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)
(585)	(585)	(585)	(585)	(585)	(585)	(585)	(585)	(585)
535	549	561	571	580	587	594	600	605
(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)
0	0	0	0	0	0	0	0	0
(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)
62	62	62	62	62	62	62	62	62
(76)	(75)	(73)	(72)	(71)	(71)	(71)	(71)	(71)
(236)	(135)	(36)	61	156	250	342	433	524
(64)	(37)	(10)	16	42	67	92	117	141
(172)	(99)	(27)	44	114	182	250	316	382

Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25
(4,419)	(4,419)	(4,419)	(4,419)	(4,419)	(4,419)	(4,419)	(4,419)	(4,419)
(295)	(295)	(295)	(295)	(295)	(295)	(295)	(295)	(295)
(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)
(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)
(1,598)	(1,572)	(1,545)	(1,519)	(1,505)	(1,505)	(1,505)	(1,505)	(1,505)
(1,598)	(1,572)	(1,545)	(1,519)	(1,505)	(1,505)	(1,505)	(1,505)	(1,505)
(927)	(981)	(1,034)	(1,087)	(1,114)	(1,114)	(1,114)	(1,114)	(1,114)
(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)

Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25

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(172)	(99)	(27)	44	114	182	250	316	382
0	0	0	0	0	0	0	0	0
(53)	(53)	(53)	(53)	(27)	0	0	0	0
(225)	(152)	(80)	(9)	87	182	250	316	382
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
27	27	27	27	13	0	0	0	0
199	125	53	(18)	(101)	(182)	(250)	(316)	(382)
225	152	80	9	(87)	(182)	(250)	(316)	(382)
(0)	0	(0)	0	(0)	0	0	0	0

CASE: UG 490
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 905

Excerpt from Staff's Final Comments in LC 79

April 18, 2024

4.8 - RNG Modeling and Appendix K

Ted Drennan, Energy Policy Analyst

Appendix K

Staff appreciates the Company's response to Staff Request 24 from Opening Comments and the additional detail provided to describe the differences between the RNG Evaluation Methodology provided in UM 2030 and methodology ultimately presented in the IRP. Staff requests that future IRPs include a clear report of any key changes in the methodology similar to that included in the Company's Reply Comments.[100]

When the Company filed its IRP on September 23, 2022, it did so without including Appendix K. The Company subsequently filed Appendix K on October 21, 2022. The Company then met with Staff to discuss its modeling of RNG on January 20, 2023, in response to Staff Request 25, which requested a meeting with the Company to discuss questions about the RNG workbook. At that time NW Natural indicated it would file a corrected version of Appendix K in February, which, as of March 23, 2023, has not been filed.

Staff has been unable to resolve all concerns as it has yet to see an updated version of Appendix K the Company had indicated it would provide. Further, Staff continues to see opportunities to improve risk inputs and modeling. However, Staff is comfortable enough with the current RNG modeling in this IRP to recommend continued use of the methodology and delay discussion of workbook improvements until future proceedings. Staff's willingness to address these issues in a future proceeding does not imply prudence for projects selected using the method.

Recommendation 34: The Company should provide an updated Appendix K which correctly describes the Company's modeling for RNG projects.

RNG Workbook

The issues regarding the RNG workbook that were discussed at the January 20 meeting included: 1) selection of "Type of Project" and associated outboard modeling, and 2) risk inputs and associated modeling.

In its response to Staff's Data Request 13, the Company explained that the "Project Type" in the RNG models submitted by the Company might not reflect the actual project because there had been additional outboard modeling, i.e., modeling that occurs outside of the RNG workbook. This outboard modeling was used in a number of ways. One way was to determine the total revenue requirement to input in the RNG model, which was derived in a cost-of-service model. The Company also used outboard models to calculate the value associated with the sale of brown gas in some of its earlier models. Where this occurred, the Company selected

[100] NW Natural Reply Comments at 53.

"Unbundled Environmental Attribute Purchase" for the project type, when the actual project was "RNG with Sale of Brown Gas." The Company addressed Staff's concern about this discrepancy between modeled projects and actual projects at the January 20 meeting. Staff understands this to be an issue with earlier models and likely will not be an issue going forward.

Staff's concerns with NW Natural's risk modeling for the RNG model in opening comments remain. In summary, these include the choice of risk distribution, the lack of inclusion of downside risk, and the lack of information on how the risk bands are selected by internal experts. For risk distribution, the Company uses a lognormal distribution for asymmetric risks but has offered no foundation for this approach.[101] Staff raised a question regarding the approach using a hypothetical example in opening comments[102] of a +/-20 percent risk band versus one with -19 percent and +20 percent. The risk distribution for the former would be assumed normal, the latter assumed lognormal. At the January 20 meeting, the Company explained under this hypothetical that the results would be similar under either lognormal or normal distributions. While this may be true in the hypothetical posed, it still does not provide rationale for the assumptions of a lognormal risk distribution. For reference, an example of the hypothetical risk data for a project included with the Company's RNG Incremental Cost Workbook is included below.

Risk Analysis Key Inputs		
RNG Volume Uncertainty		
Annual Prob RNG Supply Ceases		0.5%
Prob of Delay (1 and 2 year)	30%	5%
% Δ From Base Case	5th %	95th %
Project Volume Output	-20%	10%
Project Cost Uncertainty		
% Δ From Base Case	5th %	95th %
Carbon Intensity	-15%	15%
Payments to Investments	-5%	30%
Other non-output costs	-3%	5%
Non-offtake Variable Costs	-20%	30%
Offtake/Biogas Price	0%	0%
Other Offsetting Revenues	-12%	30%

[103]

The Company did not provide additional information on the reasons for ignoring downside risk (i.e., risks that could lower expected costs) in their modeling. Staff provided a hypothetical in opening comments for this as well.[104] In Staff's hypothetical there should be a clear preference for one project over another, but due to the Company's modeling approach the Company would be indifferent between the projects.

[101] RNG Incremental Cost Workbook.
[102] See Staff Comments at 56-57.
[103] RNG Incremental Cost Workbook, RNG Dashboard Tab.
[104] Ibid at 57.

Finally, there is a lack of a standardized approach to risk modeling, or selection of risk bands, which is still concerning to Staff. Here the Company's internal experts assess risks associated with various factors included in Table k.2 Project Evaluation Component Description.[105] There are no formal rules or processes for assigning risks, so it is not clear that results of the analysis would be the same under two different subject-matter experts. Comments from CUB highlight concerns about relying on internal experts with regard to gas heat pump adoption rates which were more optimistic than adoption rates from NEEA experts.[106] NW Natural's RNG modeling likewise relies on internal experts to assess risks associated with different projects. It is not clear to Staff whether there are policies in place at the Company to assure modeling of risks related to RNG projects are standardized, or if expert biases might systemically favor one type of project versus another. As discussed in Section **3.6 - RNG: OWNERSHIP VS. CONTRACTUAL PURCHASES**, the approach of the electric utilities, especially PacifiCorp which allows self-scoring for non-price attributes, would bring standardization and transparency to this process. Appendix K, when corrected, could also allow for additional information related to RFP modeling and scoring.

Recommendation 35: In the next IRP, the Company should provide support for risk modeling approach (i.e. lognormal vs normal risk distributions, ignoring upside risks) and ensure this topic is discussed in a technical working group meeting for the next IRP.

Recommendation 36: In the next IRP, the Company should standardize their approach to selecting risk values such that modeling could be duplicated and ensure this topic is discussed in a technical working group meeting for the next IRP.

Recommendation 37: The Company should provide an explanation for why it does not consider downside risks in its models and demonstrate that this approach results in least-cost, least-risk resources.

[105] See NW Natural IRP, Appendices at 199.
[106] See CUB comments at 10.

4.9 - RNG, Hydrogen, and Syngas

4.9.1 - RNG Availability and Cost

Ted Drennan, Energy Policy Analyst

As discussed in Opening Comments, NW Natural is placing a heavy reliance on non-emitting supply-side resources for decarbonizing their system. Staff appreciates the additional information provided by the Company regarding its cost assumptions for RNG, hydrogen, and synthetic methane. The Company's experience with RNG development and its exposure to market prices and availability helps support its near-term assumptions. However, Staff still has some concerns with how the Company's RNG costs compare to other forecasts and with the longer-term cost and availability trends. In particular, Staff has concerns regarding availability assumptions that rely on 'all-hands-on-deck' approach to RNG and the Company's minimal consideration to competition for RNG.

Staff has looked more in depth at the Company's reliance on a study from ICF. This further dive into the study has not alleviated concerns of the appropriateness of relying on the study.

The study was discussed in the Company's third technical workshop on March 28, 2022. At the discussion, it was reported the values are dependent on a deep decarbonization scenario that "requires aggressive deployment of emission reduction measures across the country."[107] This is also called an "all-hands-on-deck approach." While this approach helps demonstrate the role decarbonized fuel could play under a best-case scenario, Staff does not believe it provides a reasonable foundation for understanding potential availability because it is premised on a flawed policy assumption. Recent legislative actions in the US challenge the assumption that all groups are working together regarding emission reductions from natural gas. A few simple illustrative examples follow.

On January 6, 2023, a law in Ohio was signed that declared natural gas is green energy. From HB 507:[108]

> (43) "Green energy" means any energy generated by using an energy resource that does one or more of the following:
> (a) Releases reduced air pollutants, thereby reducing cumulative air emissions;
> (b) Is more sustainable and reliable relative to some fossil fuels.
> "Green energy" includes energy generated by using natural gas as a resource.

[107] See Supply Side Resources Technical Working Group No. 3 Presentation, slide 72 (March 28, 2022).
[108] See Sub. H.B. No. 507, 134th Ohio General Assembly (Effective Date April 7, 2023).

The Wyoming legislature considered a resolution titled "Phasing out new electric vehicle sales by 2035." While Senate Joint Resolution SJ004[109] died in committee, it was not in line with the 'all hand-on-deck" approach in the ICF study.

The Kentucky Senate approved a bill SB 4,[110] that will, "prohibit the Public Service Commission from approving a request by a utility to retire a coal-fired electric generator unless the utility demonstrates that the retirement will not have a negative impact on the reliability or the resilience of the electric grid or the affordability of the customer's electric utility rate".

More locally, parties need look no farther than the situation with the Colstrip generating plants. Here the Montana legislature passed laws that were designed to stop the majority owners from closing the power plant. The laws were found to be unconstitutional,[111] although it looks like the plant will continue to operate.

Besides the issues raised above, the methodology of the study is a concern. As discussed by ICF, the 2021 study was based off of ICF's 2019 study. The 2019 study had two scenarios, a low-resource and high-resource approach. The 2019 study contained one price curve, for the high-resource scenario. The costs were less in this scenario than the low-resource scenario.

For the 2021 update relied on by NW Natural, ICF eased the constraints on what was available to produce RNG but kept the same cost curves. Thus, the supply increased, at constant costs, which does not seem reasonable. Table 2 below shows the assumptions between the two cases in ICF's 2019 study, along with the updated assumptions in the 2021 study. The latest assumptions are substantially greater than the earlier ones.

Table 2: ICF Study Comparisons

RNG Feedstock	ICF 2019 Study: Low Resource	ICF 2019 Study: High Resource	ICF Updated Study
LFG	50% of EPA's candidate landfills	80% of EPA's candidate landfills	95% of eligible landfills
Animal Manure	30% of technically available animal manure	60% of technically available animal manure	75% of technically available
WRRF	30% of WRRFs with a capacity greater than 7.25 million gallons per day	50% of WRRFs with a capacity greater than 3.3 million gallons per day	95% of facilities w/>3.5MGD
Food Waste	40% of the food waste available at $70/dry ton	70% of the food waste available at $100/dry ton	95% @ $100/ton

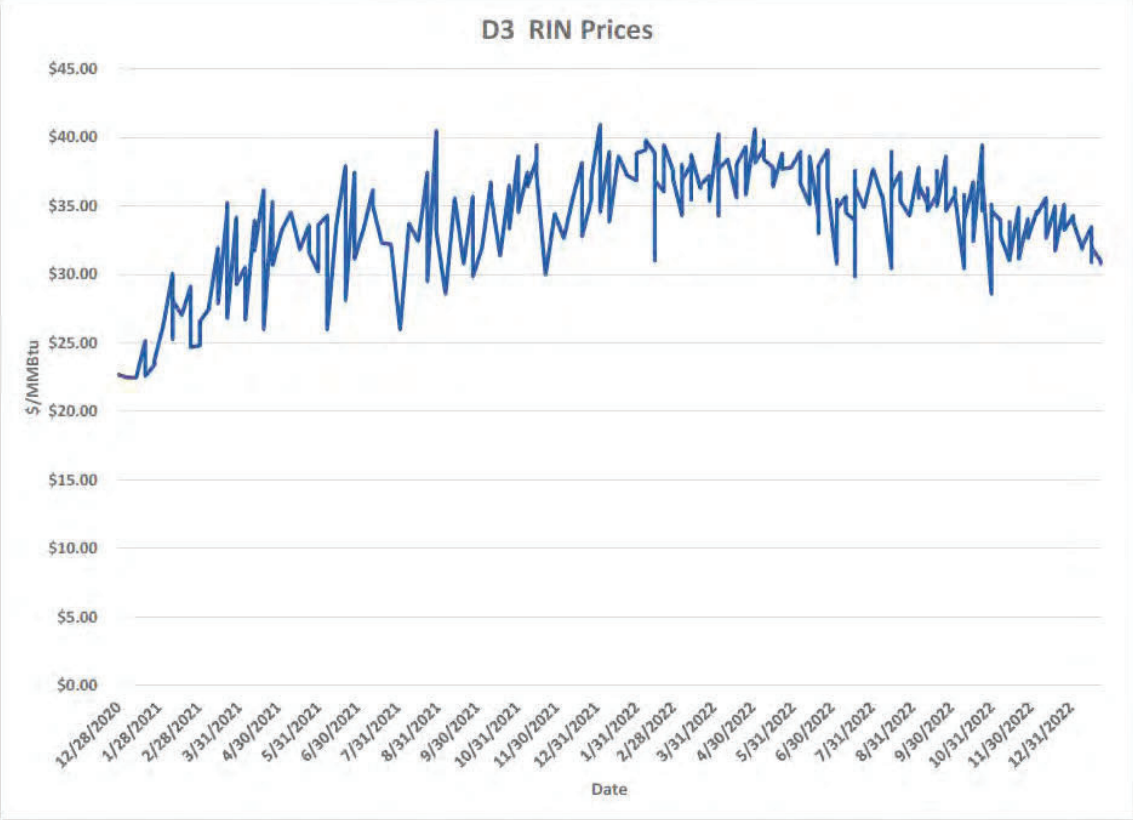
[109] See Wyoming Senate Joint Resolution No. SJ0004, Phasing Out New Electric Vehicle Sales by 2035 (last accessed March 11, 2023).
[110] See Kentucky Senate Bill 4, (adopted March 16,2023).
[111] See Tom Lutey, "Newly-passed Colstrip laws unconstitutional, court rules," Billings Gazette, October 10, 2022.

Agriculture Residue	20% of the agricultural residues available at $50/dry ton	50% of the agricultural residues available at $50/dry ton	80% @ $50/ton
Forestry and forest product residue	30% of the forest and forestry product residues available at $30/dry ton	60% of the forest and forestry product residues available at $60/dry ton	80% @ $50/ton
Energy crops	50% of the energy crops available at $50/dry ton	50% of the energy crops available at $70/dry ton	60% @ $50/ton
Municipal solid waste (MSW)	30% of the non-biogenic fraction of MSW available at $30/dry ton	60% of the non-biogenic fraction of MSW available at $100/dry ton	80% @ $50/ton
P2G	50% capacity factor for dedicated renewables	80% capacity for dedicated renewables	NA

Staff continues to have concerns with the price forecasts for RNG used by the Company. Competition for RNG is high in the renewable fuel market. Transportation RNG, with its environmental attributes represented by D3 Renewable Identification Numbers (RINs), receives premium rates. Figure 6 below highlights the historic prices for D3 RINs as reported by the EPA for 2021 through February 10, 2023. The D3 RIN prices [112] have been higher than NW Natural's current RNG projections for Tranche 2, which is estimated at $19/MMBtu. This means that NW Natural could have difficulty finding large quantities of RNG at prices much below prices of RIN RNG. In a recent filing, NW Natural discusses how the RNG market is driven by the fuels markets, including D3 RINs.[113] The Company points out that while volatile, "the overall value or RNG in these markets remain strong, with a 2-year average of over $33/mmbtu.[114]

[112] Data selected from https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rin-trades-and-price-information last accessed March 11,2023. Prices are reported at the RIN level, which were converted to $/MMBtu. One MMBtu of RNG is approximately 11.7 RINs.
[113] See UG 462, NW Natural 100, Chittum/Page 25-26, lines 14-1. The current market for D3 RINs, which is the type of RNG the majority of resources we would purchase for RNG Statute and CPP Rule compliance would generate, is quite strong.
[114] See UG 462, NW Natural 100, Chittum/Page 26, lines 3-5.

Figure 6: D3 RIN Prices2021-Feb 10, 2023



Others looking at the RNG market have differing views than those in NW Natural's IRP as well. A recent article by S&P Global[115] addresses the current market for RNG, including the competing markets for RNG, i.e., use in transportation or by utilities:

> Transportation RNG -- which is typically priced around the value of conventional gas, plus D3 RIN credits -- is currently marketable between $30-$35/MMBtu, while RNG sold to utilities, manufacturers and other end users in the voluntary market is marketable between $20-$25/MMBtu, with normal production costs around $15/MMBtu and under, Kinder Morgan's Holsapple told S&P Global.

These estimates conflict with NW Natural's RNG projections. The same S&P Global report notes that producers are expecting prices for RNG around $20/MMBtu for long-term projects:[116]

[115] See https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/natural-gas/121622-rng-industry-expects-us-voluntary-customers-to-spur-demand-after-early-transport-boom last accessed March 11,2023.
[116] Ibid.

> A recent survey of 450 RNG producers by US clean energy consultancy EcoEngineers found that many companies are beginning to draw around $20/MMBtu for RNG sold into voluntary markets on a long-term basis.

Table 3 below compares the historic maximum and minimum EPA values in Figure , the values from S&P, and NW Natural's values for Tranche 1 and 2. Even NW Natural's projections for the higher-cost Tranche 2 are lower than historical and expected costs.

Table 3: RNG Cost Comparison

	Price
Tranche 1 (1/3 of NWN RNG Supply)	Portfolio cost of $14/MMBtu
Tranche 2 (2/3 of NWN RNG Supply)	Portfolio cost of $19/MMBtu
S&P long-term utility purchase of RNG	$20-25/MMBtu
S&P Transportation RNG	$30-35/MMBtu
Historic EPA D3 Cost – minimum (1/4/2021)	$22.46/MMBtu
Historic EPA D3 Cost – maximum (1/3/2022)	$40.95/MMBtu

Request 28 from Staff's opening comments requested further discussion supporting and providing justification for RNG, hydrogen, and synthetic [methane] cost assumptions. In the Company's response, it explains that "larger and larger scale RNG projects are being developed."[117] Further, the Company suggests, "if the utility developed RNG projects become a larger percentage of the utility's RNG portfolio, then costs for NW Natural customers will trend toward production costs."[118]

Staff agrees that utility-developed RNG projects will result in prices that trend toward production costs, as utility projects are generally provided to ratepayers at cost (plus rate-of-return). However, even the Company's Tranche 1 costs are lower that production costs noted by Kinder Morgan. Thus, it does not alleviate Staff's concerns with current long-term RNG price forecasts used in the IRP. Further, in the same section NW Natural cites World Resource Institute, which forecasts project costs from $3 to $30/MMBtu. The $30 is much higher than the Tranche 2 estimates, which top out at under $20/MMBtu. Overall, Staff is not persuaded by the Company's response regarding RNG price assumptions.

Staff understands that the Company provided a scenario with higher RNG costs in the 2022 IRP, however in the next IRP Staff would like to see a sensitivity with costs based on the higher end of recent, relevant publicly available forecasts. Additionally, given the wide range of forecast RNG prices, utilizing more than two tranches may help improve accuracy for costs and availability at different price ranges.

[117] See NW Natural reply comments at 59.
[118] *Ibid*.

Prior to the Company's next IRP technical working groups, Staff plans to explore engaging an independent third party to review the reasonableness of key technology and market assumptions for use in the next IRP.

Recommendation 38: For the next IRP, the Company should provide an analysis that would examine high-cost RNG, hydrogen, and synthetic gas as a sensitivity. The cost estimates should be on the higher end of recent, relevant publicly available forecasts, and the Company should provide the sources used for each cost forecast.

Recommendation 39: For the next IRP, the Company should provide a literature review of RNG price and availability forecasts.

4.9.2 - Hydrogen and Syngas Cost and Availability

Rose Anderson, Senior Economist

As discussed in Staff Opening Comments, NW Natural's estimates for hydrogen costs appear to be on the low end of available forecasts. NW Natural's hydrogen cost trajectory, based on advice from third party consultants, is among the lowest forecasts for hydrogen prices that Staff has reviewed. However, aggressive cost declines for green hydrogen are a real possibility given that renewable energy is ever-more abundant in the region and recent policies have taken aim at significantly reducing the cost of green hydrogen.

In Opening Comments, CUB argues that NW Natural's hydrogen cost estimates are concerning in part because the Company's IRP described hydrogen electrolyzers as dispatching opportunistically based on wholesale market prices. CUB argues that any electric rate paid by NW Natural to an electric utility is not likely to reflect opportunistic wholesale market prices. Staff agrees with this assessment. However, in NW Natural's Reply Comments, the Company explains that IRP hydrogen costs include the cost of a dedicated renewable resource and are not based on opportunistic wholesale market purchases.[119,120]

Staff reviewed the sources provided by the Company for its hydrogen cost estimates and finds that the materials provided offer only minimal support for the Company's estimates. While consultants provided cost estimates for a variety of hydrogen projects, NW Natural provided no clear documentation of its process for translating the third-party studies to a hydrogen price forecast that reflects NW Natural's unique circumstances. Electrolyzer size, capacity factor, and the manner of obtaining renewable energy are all important to the cost of hydrogen, and it is unclear what assumptions were used in this IRP. For example, **[Begin Confidential]** [redacted]

[119] NW Natural Reply Comments. Page 15.
[120] NW Natural Reply to Staff DR 151.

CASE: UG 490
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 906

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April 18, 2024

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Docket No. UG 490

e-FILING REPORT COVER SHEET

COMPANY NAME: NW Natural

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ■ No ☐ Yes If yes, submit a redacted public version (or a cover letter) by email. Submit the confidential information as directed in OAR 860-001-0070 or the terms of an applicable protective order.

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Report is required by: ☐ OAR
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☐ Order
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Is this report associated with a specific docket/case? ☐ No ■ Yes, docket number: RG-41

List Key Words for this report. We use these to improve search results.

Meter Sampling Program Report for 2019, NW Natural

Send the completed Cover Sheet and the Report in an email addressed to PUC.FilingCenter@state.or.us

Send confidential information, voluminous reports, or energy utility Results of Operations Reports to PUC Filing Center, PO Box 1088, Salem, OR 97308-1088 or by delivery service to 201 High Street SE Suite 100, Salem, OR 97301.

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Docket No. UG 490

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February 12th, 2020

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Post Office Box 1088
Salem, Oregon 97308-1088

Re: RG 41: Meter Sampling Program Report for 2019

At the request of Commission Staff, Northwest Natural Gas Company, dba NW Natural, submits herewith its 2019 Meter Sampling Program Report.

As required by our Meter Testing Standards and Procedures document, the accuracies of all operating families of diaphragm meters with capacities 1000 ft^3/hr and below have been statistically analyzed for the year 2019. This analysis utilized all relevant meter tests conducted during the five calendar years between January 1, 2014 and December 31, 2019. The results of this analysis are as follows:

- As of December 31, 2019, we had 728,495 installed meters covered under the Meter Sampling Program. These meters formed 410 meter families. This total does not include meters determined to be non-conforming.
- Over the course of 2019, the company tested 5,271 meters. Over the five-year period of 2014 through 2019, the company had a total of 29,353 meter samples from which to base its results.
- 404 meter families either had sufficient meter samples to establish statistical confidence in their accuracy, or are so new that they do not yet require minimum sampling. These meter families amount to 706,867 meters, or 97 percent of the total meter population. The performances of these families are exhibited in Appendix A.
- 9 new meter families were added in 2019. 3 meter families were removed from service due to small family size, during the normal course of business.
- 34 meter families, consisting of a total of 42,046 meters, are not conforming. Due to the number of meters requiring change-out (5.5% of the total population), these meters have been put on the list to be removed over the course of the next 4 years, by December 2023, per Meter Sampling Program (MSP) guidelines outlined in NW Natural Engineering Procedure Z-1. The performance of these families is exhibited in Appendix B.
- A further breakdown of the non-conforming meter families and associated meters described above are as follows, the performance of these families is exhibited in Appendix B:
    - 17 meter families, totaling 41,876 meters had sufficient meter tests available to have their accuracy determined statistically and determined non-conforming.
    - 15 meter families, totaling 52 meters, will be removed from service due to their small population size and age.
    - 2 meter families, totaling 118 meters will be removed from service due to small family size and sampling requirements exceeding 34% of the total family population.
- Compared to the results above, the Year 2018 report resulted in 11,566 meters being put on the list for removal by the end of 2019.

If you have any questions or comments, please contact me at (503) 226-4211 ext. 5542.

Sincerely,
/s/ *Michael J. McKenzie*

Michael J. McKenzie
Gas Measurement and Station Design Engineering Supervisor

cc: Andy Fortier
Jon Huddleston
Cliff Crawford
Joe Karney
Dave Weber
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Appendix A

Meter Families in Conformance

Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
570	0	2018	Rockwell	275	0	1	1		
560	0	2018	American	250	0	3	14	1	
487	0	2018	American	800	0	198	4		
505	507	2018	American	1000	0	356	7	1	
562	0	2018	American	250	0	695			
475	0	2018	American	630	0	4744	18	2	
602	0	2018	Itron	250	0	8178	20		
561	0	2018	American	250	0	9707	51	1	
125	0	2017	Rockwell	200	1	1	3		
470	472	2017	American	425	1	1			
520	0	2017	Rockwell	415	1	1			
560	0	2017	American	250	1	1	14		
570	0	2017	Rockwell	275	1	3	3		
562	0	2017	American	250	1	22			
487	0	2017	American	800	1	58	2		
505	507	2017	American	1000	1	203	7		
475	0	2017	American	630	1	1707	25	2	
602	0	2017	Itron	250	1	4603	30		
561	0	2017	American	250	1	11849	91	2	
140	0	2016	Sprague	175	2	1	3		
485	0	2016	American	800	2	1			
590	0	2016	Lancaster	250	2	1	2		
130	0	2016	American	175	2	2	7		
570	0	2016	Rockwell	275	2	2	2		
595	600	2016	Schlumberger	250	2	2			
572	0	2016	Sensus	275	2	3			
505	507	2016	American	1000	2	533	22	1	
475	0	2016	American	630	2	1650	24	1	
602	0	2016	Itron	250	2	4367	30		
561	0	2016	American	250	2	12685	98		
560	0	2015	American	250	3	1	8		
572	0	2015	Sensus	275	3	2	1		
Perf	**Alt. Perf**	**Year Set**	**Manufacturer**	**Size**	**Age**	**# Meters in Family**	**# OK**	**# Fast**	**# Slow**
505	507	2015	American	1000	3	365	21		
475	0	2015	American	630	3	1274	55	1	
561	0	2015	American	250	3	17981	171	3	
120	0	2014	Rockwell	175	4	1	2		
572	0	2014	Sensus	275	4	1	1		
570	0	2014	Rockwell	275	4	2	3		
585	0	2014	Sprague	250	4	2			
130	0	2014	American	175	4	3	2		
560	0	2014	American	250	4	5	5		

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505	507	2014	American	1000	4	447	34		
475	0	2014	American	630	4	1581	64		
561	0	2014	American	250	4	14738	205	1	
120	0	2013	Rockwell	175	5	1			
130	0	2013	American	175	5	1			
450	0	2013	Schlumberger	400	5	1			
510	515	2013	Rockwell	310	5	1			
570	0	2013	Rockwell	275	5	1			
572	0	2013	Sensus	275	5	1	1		
560	0	2013	American	250	5	4			
505	507	2013	American	1000	5	384	34		
475	0	2013	American	630	5	1521	83		
561	0	2013	American	250	5	15370	269	1	2
120	0	2012	Rockwell	175	6	1			
470	472	2012	American	425	6	1			
555	0	2012	American	310	6	1			
595	600	2012	Schlumberger	250	6	1			
570	0	2012	Rockwell	275	6	3	1		
572	0	2012	Sensus	275	6	4			
560	0	2012	American	250	6	6			
471	0	2012	American	425	6	10			
505	507	2012	American	1000	6	407	41	1	
475	0	2012	American	630	6	1465	60	1	
561	0	2012	American	250	6	11993	178	1	
485	0	2011	American	800	7	1			
510	515	2011	Rockwell	310	7	1			
520	0	2011	Rockwell	415	7	1			
570	0	2011	Rockwell	275	7	1			
590	0	2011	Lancaster	250	7	1			
140	0	2011	Sprague	175	7	2			
560	0	2011	American	250	7	3			
572	0	2011	Sensus	275	7	86	3		
471	0	2011	American	425	7	109	10		
505	507	2011	American	1000	7	377	44	1	
475	0	2011	American	630	7	1059	43	1	
561	0	2011	American	250	7	10703	166		
120	0	2010	Rockwell	175	8	1	1		
510	515	2010	Rockwell	310	8	1			

Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
590	0	2010	Lancaster	250	8	1			
470	472	2010	American	425	8	2			
560	0	2010	American	250	8	2			
572	0	2010	Sensus	275	8	16	1		
471	0	2010	American	425	8	101	9		
475	0	2010	American	630	8	667	32		
561	0	2010	American	250	8	10129	199	3	
510	515	2009	Rockwell	310	9	1			
555	0	2009	American	310	9	1			

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140	0	2009	Sprague	175	9	2			
590	0	2009	Lancaster	250	9	2	1		
125	0	2009	Rockwell	200	9	3			
471	0	2009	American	425	9	3	1		
520	0	2009	Rockwell	415	9	3			
470	472	2009	American	425	9	4			
585	0	2009	Sprague	250	9	5			
570	0	2009	Rockwell	275	9	16	1		
130	0	2009	American	175	9	19	1		
505	507	2009	American	1000	9	295	31	4	
572	0	2009	Sensus	275	9	778	19		
561	0	2008	American	250	10	23031	424	49	
560	0	2007	American	250	11	193	25		
470	472	2007	American	425	11	234	28		2
471	0	2007	American	425	11	482	78	8	
561	0	2007	American	250	11	22000	437	42	1
470	472	2006	American	425	12	34	38	1	
560	0	2006	American	250	12	622	47	1	
561	0	2006	American	250	12	21524	359	24	1
450	0	2005	Schlumberger	400	13	8	7		
300	540	2005	Rockwell	800	13	11	11		
570	0	2005	Rockwell	275	13	12	10		
452	0	2005	Actaris	400	13	17	14		
470	472	2005	American	425	13	23	14		
520	0	2005	Rockwell	415	13	48	19		
560	0	2005	American	250	13	78	32	1	1
561	0	2005	American	250	13	1650	88	13	
572	0	2005	Sensus	275	13	24724	390	48	
450	0	2004	Schlumberger	400	14	8	11		
272	0	2004	Actaris	1000	14	15	33	2	
595	600	2004	Schlumberger	250	14	32	16		
585	0	2004	Sprague	250	14	63	28		
470	472	2004	American	425	14	88	22		
520	0	2004	Rockwell	415	14	107	22		
452	0	2004	Actaris	400	14	437	53	2	3
570	0	2004	Rockwell	275	14	3611	56		
572	0	2004	Sensus	275	14	13950	205	17	2
585	0	2003	Sprague	250	15	13	18		
Perf	**Alt. Perf**	**Year Set**	**Manufacturer**	**Size**	**Age**	**# Meters in Family**	**# OK**	**# Fast**	**# Slow**
500	502	2003	American	1000	15	24	21		
450	0	2003	Schlumberger	400	15	29	17		
595	600	2003	Schlumberger	250	15	60	17		1
520	0	2003	Rockwell	415	15	154	74	1	
470	472	2003	American	425	15	209	66	3	
560	0	2003	American	250	15	453	58	1	
570	0	2003	Rockwell	275	15	19865	292	5	2
470	472	2002	American	425	16	434	46	1	
595	600	2002	Schlumberger	250	16	3282	177		2

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560	0	2002	American	250	16	8504	123	5	
570	0	2002	Rockwell	275	16	10821	163	3	
500	502	2001	American	1000	17	11	10	1	1
585	0	2001	Sprague	250	17	49	17		
270	0	2001	Schlumberger	1000	17	53	17		
595	600	2001	Schlumberger	250	17	3815	176	3	1
570	0	2001	Rockwell	275	17	8708	123	3	1
560	0	2001	American	250	17	9423	167	1	1
270	0	2000	Schlumberger	1000	18	18	13		
585	0	2000	Sprague	250	18	36	30	2	
470	472	2000	American	425	18	414	73	3	
595	600	2000	Schlumberger	250	18	3266	297	18	10
570	0	2000	Rockwell	275	18	8497	120	19	1
560	0	2000	American	250	18	11261	236	7	1
125	0	1999	Rockwell	200	19	139	21		
590	0	1999	Lancaster	250	19	151	22		
470	472	1999	American	425	19	250	48	1	
570	0	1999	Rockwell	275	19	10534	190	25	3
560	0	1999	American	250	19	11252	166	3	1
140	0	1998	Sprague	175	20	8	10		
270	0	1998	Schlumberger	1000	20	26	16		
590	0	1998	Lancaster	250	20	28	14		
125	0	1998	Rockwell	200	20	82	27		
500	502	1998	American	1000	20	87	47	7	
470	472	1998	American	425	20	160	65	6	
450	0	1998	Schlumberger	400	20	445	50		
585	0	1998	Sprague	250	20	5414	142		
560	0	1998	American	250	20	14450	258	21	2
485	0	1997	American	800	21	8	7		
510	515	1997	Rockwell	310	21	9	10		
520	0	1997	Rockwell	415	21	58	52	4	
450	0	1997	Schlumberger	400	21	64	18		
140	0	1997	Sprague	175	21	474	56	1	2
590	0	1997	Lancaster	250	21	2123	50		3
570	0	1997	Rockwell	275	21	2363	51	1	
585	0	1997	Sprague	250	21	5932	128	1	2
485	0	1996	American	800	22	8	11		
450	0	1996	Schlumberger	400	22	270	49		
Perf	**Alt. Perf**	**Year Set**	**Manufacturer**	**Size**	**Age**	**# Meters in Family**	**# OK**	**# Fast**	**# Slow**
130	0	1996	American	175	22	1045	48	1	
585	0	1996	Sprague	250	22	4428	118		
570	0	1996	Rockwell	275	22	7687	140	4	
560	0	1996	American	250	22	11115	253	8	1
480	486	1995	American	800	23	18	14		2
130	0	1995	American	175	23	553	66	3	1
585	0	1995	Sprague	250	23	1520	42		
590	0	1995	Lancaster	250	23	4840	151	7	11
570	0	1995	Rockwell	275	23	6500	136	8	2

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560	0	1995	American	250	23	8197	199	12	1
555	0	1994	American	310	24	8	11	1	
510	515	1994	Rockwell	310	24	44	32		3
470	472	1994	American	425	24	225	32		
125	0	1994	Rockwell	200	24	388	80	6	1
120	0	1994	Rockwell	175	24	1375	74	1	2
585	0	1994	Sprague	250	24	1658	51	1	
130	0	1994	American	175	24	2638	118	9	
590	0	1994	Lancaster	250	24	4386	184	9	6
560	0	1994	American	250	24	6174	123	6	
570	0	1993	Rockwell	275	25	61	32	1	
510	515	1993	Rockwell	310	25	98	46	5	2
450	0	1993	Schlumberger	400	25	192	36		
125	0	1993	Rockwell	200	25	483	82	7	1
140	0	1993	Sprague	175	25	653	34		1
120	0	1993	Rockwell	175	25	2664	123	6	3
590	0	1993	Lancaster	250	25	2841	75	1	
130	0	1993	American	175	25	3172	123	13	3
585	0	1993	Sprague	250	25	3842	120		
560	0	1993	American	250	25	4073	123	2	2
470	472	1992	American	425	26	145	28		
140	0	1992	Sprague	175	26	566	35		2
125	0	1992	Rockwell	200	26	617	40	1	
585	0	1992	Sprague	250	26	2107	68		
590	0	1992	Lancaster	250	26	2667	95	1	1
560	0	1992	American	250	26	4806	103		
120	0	1992	Rockwell	175	26	6737	286	9	2
470	472	1991	American	425	27	27	26	2	
480	486	1991	American	800	27	47	36	4	
510	515	1991	Rockwell	310	27	213	24		2
140	0	1991	Sprague	175	27	451	54		3
125	0	1991	Rockwell	200	27	701	39		
590	0	1991	Lancaster	250	27	1724	73		1
120	0	1991	Rockwell	175	27	3858	178	6	5
130	0	1991	American	175	27	4898	138	11	5
560	0	1991	American	250	27	5576	208	4	2
480	486	1990	American	800	28	26	18		
125	0	1990	Rockwell	200	28	294	74	10	
Perf	**Alt. Perf**	**Year Set**	**Manufacturer**	**Size**	**Age**	**# Meters in Family**	**# OK**	**# Fast**	**# Slow**
140	0	1990	Sprague	175	28	1021	101		6
590	0	1990	Lancaster	250	28	1323	56	1	
130	0	1990	American	175	28	3121	130	18	1
120	0	1990	Rockwell	175	28	3569	145	12	3
570	0	1990	Rockwell	275	28	5397	133	12	3
560	0	1990	American	250	28	6319	195	2	6
555	0	1989	American	310	29	15	28	2	
125	0	1989	Rockwell	200	29	524	74	2	
140	0	1989	Sprague	175	29	760	40		3

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590	0	1989	Lancaster	250	29	1313	72		
130	0	1989	American	175	29	3255	150	10	2
120	0	1989	Rockwell	175	29	3510	147	7	4
560	0	1989	American	250	29	7022	229	4	4
520	0	1988	Rockwell	415	30	49	19		1
585	0	1988	Sprague	250	30	180	22		
140	0	1988	Sprague	175	30	753	59	2	3
120	0	1988	Rockwell	175	30	2189	94	6	2
130	0	1988	American	175	30	3119	137	17	2
560	0	1988	American	250	30	3151	95	1	2
555	0	1987	American	310	31	35	36	3	1
520	0	1987	Rockwell	415	31	43	27	1	2
125	0	1987	Rockwell	200	31	556	81	3	1
120	0	1987	Rockwell	175	31	2220	118	11	2
140	0	1987	Sprague	175	31	2967	125		10
130	0	1987	American	175	31	5904	205	23	2
510	515	1986	Rockwell	310	32	18	13		
555	0	1986	American	310	32	85	34	1	
140	0	1986	Sprague	175	32	964	58	1	1
120	0	1986	Rockwell	175	32	1316	57	2	1
130	0	1986	American	175	32	3992	138	16	2
560	0	1986	American	250	32	6218	194	8	
470	472	1985	American	425	33	24	26	2	
140	0	1985	Sprague	175	33	1147	65	1	7
560	0	1985	American	250	33	1462	42	1	
120	0	1985	Rockwell	175	33	1941	91	13	1
510	515	1984	Rockwell	310	34	15	15	1	1
485	0	1984	American	800	34	72	25		
470	472	1984	American	425	34	109	25		
140	0	1984	Sprague	175	34	708	45		1
125	0	1984	Rockwell	200	34	2109	92	11	1
130	0	1984	American	175	34	4786	182	19	2
470	472	1983	American	425	35	26	16		
140	0	1983	Sprague	175	35	816	93	3	4
125	0	1983	Rockwell	200	35	1763	89	4	1
130	0	1983	American	175	35	3002	127	18	2
470	472	1982	American	425	36	19	11		
520	0	1982	Rockwell	415	36	36	18		
Perf	**Alt. Perf**	**Year Set**	**Manufacturer**	**Size**	**Age**	**# Meters in Family**	**# OK**	**# Fast**	**# Slow**
510	515	1982	Rockwell	310	36	85	33		2
120	0	1982	Rockwell	175	36	1172	79	12	1
125	0	1982	Rockwell	200	36	3102	113	8	1
505	507	1981	American	1000	37	9	11		2
555	0	1981	American	310	37	27	26	1	1
485	0	1981	American	800	37	31	15		
520	0	1981	Rockwell	415	37	230	36		1
140	0	1981	Sprague	175	37	632	41		1
125	0	1981	Rockwell	200	37	2469	89	11	2

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485	0	1980	American	800	38	19	18	2	1
555	0	1980	American	310	38	63	40	4	
520	0	1980	Rockwell	415	38	75	39	1	
140	0	1980	Sprague	175	38	333	35		3
125	0	1980	Rockwell	200	38	1816	88	12	
130	0	1980	American	175	38	6181	243	17	1
520	0	1979	Rockwell	415	39	74	39	1	2
140	0	1979	Sprague	175	39	132	35	1	2
510	515	1979	Rockwell	310	39	170	49	2	2
120	0	1979	Rockwell	175	39	1617	93	10	4
130	0	1979	American	175	39	6381	203	13	4
520	0	1978	Rockwell	415	40	37	15		
140	0	1978	Sprague	175	40	271	77		4
120	0	1978	Rockwell	175	40	1451	101	6	5
125	0	1978	Rockwell	200	40	1580	94	5	
510	515	1977	Rockwell	310	41	154	39		1
120	0	1977	Rockwell	175	41	1352	89	4	3
130	0	1977	American	175	41	3264	126	3	
510	515	1976	Rockwell	310	42	278	43		1
140	0	1976	Sprague	175	42	1094	64	1	1
130	0	1975	American	175	43	24	14		
140	0	1975	Sprague	175	43	719	94		2
120	0	1975	Rockwell	175	43	1800	98	12	2
140	0	1974	Sprague	175	44	617	39		1
120	0	1974	Rockwell	175	44	2592	158	17	3
120	0	1973	Rockwell	175	45	661	59	2	
130	0	1973	American	175	45	727	83	9	
140	0	1973	Sprague	175	45	2880	143	3	8
140	0	1972	Sprague	175	46	148	37		2
120	0	1972	Rockwell	175	46	846	84	10	1
130	0	1972	American	175	46	2694	95	13	1
140	0	1971	Sprague	175	47	985	59		7
130	0	1971	American	175	47	1067	100	6	1
140	0	1970	Sprague	175	48	346	57		6
140	0	1968	Sprague	175	50	1006	76		16
505	507	2007	American	1000	11	376	71	9	
585	0	1991	Sprague	250	27	746	24		
475	0	2019	American	630	0	467	1		
Perf	**Alt. Perf**	**Year Set**	**Manufacturer**	**Size**	**Age**	**# Meters in Family**	**# OK**	**# Fast**	**# Slow**
487	0	2019	American	800	0	18			
505	507	2019	American	1000	0	145			
520	0	2018	Rockwell	415	1	1			
561	0	2019	American	250	0	2991	2		
562	0	2019	American	250	0	31	1		
602	0	2019	Itron	250	0	569	1		
570	0	2019	Rockwell	275	0	2	1		
120	0	1981	Rockwell	175	38	684	80	9	1
120	0	1983	Rockwell	175	36	1355	93	10	1

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140	0	1994	Sprague	175	25	591	31	0	3
480	486	2001	American	800	18	13	12	1	0
555	0	1984	American	310	35	214	21	0	1
120	0	1970	Rockwell	175	49	631	85	5	
140	0	1982	Sprague	175	37	581	50	2	3
470	472	1989	American	425	30	33	15	0	0
470	472	1995	American	425	24	87	20	0	0
480	486	1989	American	800	30	25	13	0	0
510	515	1981	Rockwell	310	38	200	62	5	3
520	0	1983	Rockwell	415	36	17	15	1	0
570	0	1994	Rockwell	275	25	5064	107	6	0
570	0	1998	Rockwell	275	21	5447	98	5	1
570	0	2008	Rockwell	275	11	6	1	0	0
120	0	1998	Rockwell	175	21	73	19	0	0
300	540	1996	Rockwell	800	23	29	14	0	1
300	540	2002	Rockwell	800	17	6	1	0	0
450	0	1999	Schlumberger	400	20	99	20	0	0
520	0	1977	Rockwell	415	42	42	15	0	1
520	0	1991	Rockwell	415	28	73	30	1	0
555	0	1997	American	310	22	22	19	2	1
130	0	1978	American	175	41	1553	89	10	1
480	486	1996	American	800	23	7	6	0	0
480	486	2002	American	800	17	22	12	0	0
520	0	1992	Rockwell	415	27	69	18	0	1
570	0	1991	Rockwell	275	28	2883	95	8	0
120	0	1976	Rockwell	175	43	1087	83	7	2
120	0	1980	Rockwell	175	39	1009	87	10	
120	0	1984	Rockwell	175	35	1442	89	11	1
130	0	1985	American	175	34	2087	87	11	3
130	0	1992	American	175	27	1406	92	10	0
452	0	2003	Actaris	400	16	96	31	1	2
505	507	1980	American	1000	39	7	6	0	0
570	0	1989	Rockwell	275	30	751	40	1	0
585	0	1999	Sprague	250	20	243	24	0	0
120	0	1969	Rockwell	175	50	183	66	4	0
125	0	1979	Rockwell	200	40	155	36	1	0
480	486	1992	American	800	27	23	19	1	0
500	502	2002	American	1000	17	36	25	1	1
Perf	**Alt. Perf**	**Year Set**	**Manufacturer**	**Size**	**Age**	**# Meters in Family**	**# OK**	**# Fast**	**# Slow**
480	486	1993	American	800	26	31	28	3	2
120	0	1996	Rockwell	175	23	735	81	4	0
120	0	1997	Rockwell	175	22	164	36	1	0
125	0	1986	Rockwell	200	33	356	65	3	0
510	515	1973	Rockwell	310	46	87	19	0	1
120	0	1995	Rockwell	175	24	327	75	6	0
125	0	1988	Rockwell	200	31	415	39	1	0
125	0	1996	Rockwell	200	23	233	23	0	0
505	507	2008	American	1000	11	300	71	11	0

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510	515	1987	Rockwell	310	32	210	48	2	4
510	515	1992	Rockwell	310	27	118	49	2	5
140	0	1977	Sprague	175	42	313	27	0	2
470	472	1997	American	425	22	286	78	6	0
510	515	1978	Rockwell	310	41	99	47	2	2
510	515	1983	Rockwell	310	36	109	49	2	0
520	0	1996	Rockwell	415	23	97	46	2	1
555	0	1983	American	310	36	90	35	1	0
555	0	1985	American	310	34	109	34	1	0
560	0	1987	American	250	32	430	26	0	0
570	0	1992	Rockwell	275	27	130	55	5	0
572	0	2008	Sensus	275	11	38	28	1	0
470	472	1987	American	425	32	120	52	2	0
510	515	1996	Rockwell	310	23	24	13	0	1
520	0	1995	Rockwell	415	24	287	69	9	2
585	0	2002	Sprague	250	17	44	16	0	0
590	0	1988	Lancaster	250	31	75	19	0	0
590	0	1996	Lancaster	250	23	26	15	0	0
470	472	1993	American	425	26	61	38	6	0
470	472	1996	American	425	23	11	12	1	0
470	472	2001	American	425	18	58	31	1	0
470	472	2008	American	425	11	12	10	0	0
510	515	1990	Rockwell	310	29	204	62	6	3
125	0	1995	Rockwell	200	24	70	45	5	0
130	0	1997	American	175	22	200	47	1	0
470	472	1988	American	425	31	41	36	4	0
471	0	2008	American	425	11	39	34	3	0
510	515	1974	Rockwell	310	45	24	24	0	4
520	0	1994	Rockwell	415	25	91	19	0	1
120	0	1968	Rockwell	175	51	75	31	1	0
470	472	1990	American	425	29	26	13	0	0
510	515	1989	Rockwell	310	30	85	31	1	1
470	472	1986	American	425	33	54	18	0	0
520	0	2000	Rockwell	415	19	84	44	6	0
					Totals	**706867**	**23402**	**1197**	**346**

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Appendix B
Meter Families Not Conforming (To Be Removed Over 4 Years)

Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	Determination
120	0	2018	Rockwell	175	0	1	Determined
130	0	2018	American	175	0	1	Determined
140	0	2018	Sprague	175	0	1	Determined
561	0	2009	American	250	9	13443	Determined
452	0	2008	Actaris	400	10	1	Small Family
510	515	2008	Rockwell	310	10	1	Small Family
555	0	2008	American	310	10	1	Small Family
590	0	2008	Lancaster	250	10	1	Small Family
595	600	2008	Schlumberger	250	10	1	Small Family
140	0	2008	Sprague	175	10	2	Small Family
120	0	2008	Rockwell	175	10	3	Small Family
130	0	2008	American	175	10	3	Small Family
125	0	2008	Rockwell	200	10	5	Small Family
560	0	2008	American	250	10	6	Small Family
572	0	2006	Sensus	275	12	7584	Determined
125	0	2004	Rockwell	200	14	1	Small Family
561	0	2002	American	250	16	1	Small Family
500	502	1999	American	1000	19	11	Determined
560	0	1997	American	250	21	14257	Determined
475	0	1985	American	630	33	1	Small Family
510	515	1980	Rockwell	310	38	115	Determined
485	0	1978	American	800	40	4	Determined
130	0	1974	American	175	44	4583	Determined
120	0	1971	Rockwell	175	47	462	Determined
510	515	1975	Rockwell	310	43	26	Determined
570	0	2008	Rockwell	275	11	5	Small Family
300	540	2002	Rockwell	800	17	20	Determined
480	486	2000	American	800	19	22	Determined
485	0	1982	American	800	37	36	Determined
130	0	1976	American	175	43	1311	Determined
485	0	1987	American	800	32	11	Determined
300	540	1997	Rockwell	800	22	8	Determined
510	515	1988	Rockwell	310	31	102	Sampling Limit
520	0	1993	Rockwell	415	26	16	Sampling Limit
					Total	**42046**	

Staff/906
Dlouhy/13

Oregon Public Utility Commission

Docket No. UG 490

e-FILING REPORT COVER SHEET

COMPANY NAME: NW Natural

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☐ No ☐ Yes If yes, submit a redacted public version (or a cover letter) by email. Submit the confidential information as directed in OAR 860-001-0070 or the terms of an applicable protective order.

Select report type: ☐ RE (Electric) ☐ RG (Gas) ☐ RW (Water) ☐ RT (Telecommunications)
☐ RO (Other, for example, industry safety information)

Did you previously file a similar report? ☐ No ☐ Yes, report docket number: RG 41

Report is required by: ☐ OAR
☐ Statute
☐ Order
Note: A one-time submission required by an order is a compliance filing and not a report (file compliance in the applicable docket)
☑ Other At request of Commission Staff
(For example, federal regulations, or requested by Staff)

Is this report associated with a specific docket/case? ☐ No ☐ Yes, docket number: RG 41

List Key Words for this report. We use these to improve search results.

Meter Sampling for 2020, NW Natural

Send the completed Cover Sheet and the Report in an email addressed to PUC.FilingCenter@state.or.us

Send confidential information, voluminous reports, or energy utility Results of Operations Reports to PUC Filing Center, PO Box 1088, Salem, OR 97308-1088 or by delivery service to 201 High Street SE Suite 100, Salem, OR 97301.

Print

Docket No. UG 490

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February 16, 2021

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Post Office Box 1088
Salem, Oregon 97308-1088

Re: RG 41: Meter Sampling Program Report for 2020

At the request of Commission Staff, Northwest Natural Gas Company, dba NW Natural, submits herewith its 2020 Meter Sampling Program Report.

As required by our Meter Testing Standards and Procedures document, the accuracies of all operating families of diaphragm meters with capacities 1000 ft^3/hr and below have been statistically analyzed for the year 2020. This analysis utilized all relevant meter tests conducted during the five calendar years between January 1, 2015 and December 31, 2020. The results of this analysis are as follows:

- As of December 31, 2020, 732,541 installed meters are covered under the Meter Sampling Program. These meters formed 383 distinct meter families. This total does not include meters determined to be non-conforming.
- Over the course of 2020, the company tested 8,247 meters. Over the five-year period of 2015 through 2020, the company had a total of 31,269 meter samples from which to base its results.
- 372 meter families either had sufficient meter samples to establish statistical confidence in their accuracy, or are so new that they do not yet require minimum sampling. These meter families amount to 699,268 meters, or 95 percent of the total meter population. The performances of these families are exhibited in Appendix A.
- 11 new meter families were added in 2020. 20 meter families were removed from service due to small family size, during the normal course of business. 7 meter families were removed from service due to the number of supplementary samples required exceeding 50% of the family size, with a family size less than 100 meters.
- 40 meter families, consisting of a total of 27,204 meters, are not conforming. Due to the number of meters requiring change-out (3.7% of the total population), these meters have been put on the list to be removed over the course of the next 4 years, by December 2024, per Meter Sampling Program (MSP) guidelines outlined in NW Natural Engineering Procedure Z-1. The performance of these families is exhibited in Appendix B.
- A further breakdown of the non-conforming meter families and associated meters described above are as follows, the performance of these families is exhibited in Appendix B:
    - 13 meter families, totaling 27,069 meters had sufficient meter tests available to have their accuracy determined statistically and determined non-conforming.

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- 20 meter families, totaling 45 meters, will be removed from service due to their small population size and age.
- 7 meter families, totaling 90 meters, will be removed from service due to a family size less than 100 meters, and sampling requirements exceeding 50% of the total family population.

- Compared to the results above, the Year 2019 report resulted in 42,046 meters being put on the list for removal by December 2023.
- Regarding the planned 4-year removal of meters determined non-conforming in 2019, 15,084 meters remain of the 42,046 meters determined non-conforming for removal in 2020 to 2023. The remaining meters are planned to be removed by December 2023.

If you have any questions or comments, please contact me at 503-610-7494.

Sincerely,
/s/ *Michael J. McKenzie*

Michael J. McKenzie
Gas Measurement and Station Design Engineering Supervisor
Telephone: 503-610-7494
Email: mike.mckenzie@nwnatural.com

cc:

Andy Fortier	Dave Weber
Jon Huddleston	Kim Heiting
Cliff Crawford	Joe Karney

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Appendix A
Meter Families in Conformance

Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
120	0	1970	Rockwell	175	50	622	92	5	0
120	0	1974	Rockwell	175	46	2547	162	18	4
120	0	1975	Rockwell	175	45	1776	98	13	1
120	0	1977	Rockwell	175	43	1334	89	5	3
120	0	1978	Rockwell	175	42	1431	104	5	4
120	0	1979	Rockwell	175	41	1596	96	8	5
120	0	1980	Rockwell	175	40	999	90	9	0
120	0	1981	Rockwell	175	39	672	83	10	1
120	0	1982	Rockwell	175	38	1155	87	14	1
120	0	1984	Rockwell	175	36	1426	92	14	1
120	0	1985	Rockwell	175	35	1916	100	13	1
120	0	1987	Rockwell	175	33	2193	119	12	1
120	0	1988	Rockwell	175	32	2158	100	9	2
120	0	1989	Rockwell	175	31	3481	142	8	3
120	0	1990	Rockwell	175	30	3528	145	12	1
120	0	1991	Rockwell	175	29	3804	187	6	4
120	0	1992	Rockwell	175	28	6669	268	9	3
120	0	1993	Rockwell	175	27	2631	123	5	3
120	0	1994	Rockwell	175	26	1359	63	2	2
120	0	1996	Rockwell	175	24	730	86	4	0
120	0	2012	Rockwell	175	8	1	0	0	0
120	0	2013	Rockwell	175	7	1	0	0	0
120	0	2014	Rockwell	175	6	1	0	0	0
125	0	1978	Rockwell	200	42	1556	98	6	1
125	0	1979	Rockwell	200	41	153	36	1	0
125	0	1980	Rockwell	200	40	1806	88	12	0
125	0	1981	Rockwell	200	39	2452	96	14	1
125	0	1982	Rockwell	200	38	3069	114	8	0
125	0	1983	Rockwell	200	37	1744	94	5	1
125	0	1987	Rockwell	200	33	553	24	0	0
125	0	1989	Rockwell	200	31	522	68	0	0
125	0	1991	Rockwell	200	29	695	40	0	0
125	0	1993	Rockwell	200	27	478	73	7	2
125	0	1994	Rockwell	200	26	384	76	6	1
125	0	1995	Rockwell	200	25	70	45	5	0
125	0	1996	Rockwell	200	24	231	27	0	0
125	0	1998	Rockwell	200	22	82	25	0	0

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
125	0	2017	Rockwell	200	3	1	3	0	0
125	0	2019	Rockwell	200	1	1	2	0	0
130	0	1971	American	175	49	1049	104	7	1
130	0	1973	American	175	47	719	82	10	0
130	0	1975	American	175	45	24	13	0	0
130	0	1977	American	175	43	3214	128	7	1
130	0	1979	American	175	41	6308	220	13	3
130	0	1980	American	175	40	6120	243	17	1
130	0	1983	American	175	37	2943	145	21	3
130	0	1984	American	175	36	4720	195	20	4
130	0	1986	American	175	34	3947	143	15	1
130	0	1987	American	175	33	5849	196	23	2
130	0	1988	American	175	32	3084	147	17	1
130	0	1989	American	175	31	3223	147	15	1
130	0	1990	American	175	30	3091	132	18	1
130	0	1991	American	175	29	4854	129	18	5
130	0	1993	American	175	27	3136	119	15	2
130	0	1995	American	175	25	546	66	2	0
130	0	1996	American	175	24	1039	45	1	0
130	0	1997	American	175	23	200	51	1	0
130	0	2013	American	175	7	1	0	0	0
130	0	2014	American	175	6	3	0	0	0
130	0	2016	American	175	4	2	7	0	0
140	0	1968	Sprague	175	52	986	76	0	16
140	0	1970	Sprague	175	50	334	35	0	2
140	0	1971	Sprague	175	49	959	72	0	8
140	0	1972	Sprague	175	48	148	36	0	2
140	0	1973	Sprague	175	47	2844	145	3	8
140	0	1974	Sprague	175	46	609	38	0	2
140	0	1975	Sprague	175	45	702	47	0	2
140	0	1976	Sprague	175	44	1078	63	2	2
140	0	1979	Sprague	175	41	129	36	1	2
140	0	1981	Sprague	175	39	622	38	0	1
140	0	1982	Sprague	175	38	568	49	2	4
140	0	1983	Sprague	175	37	805	52	0	3
140	0	1984	Sprague	175	36	699	34	0	3
140	0	1985	Sprague	175	35	1138	65	1	6
140	0	1986	Sprague	175	34	949	48	1	3
140	0	1987	Sprague	175	33	2931	122	0	13
140	0	1988	Sprague	175	32	738	61	2	2

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
140	0	1989	Sprague	175	31	753	35	0	3
140	0	1990	Sprague	175	30	1010	101	0	4
140	0	1991	Sprague	175	29	438	32	0	3
140	0	1992	Sprague	175	28	562	31	0	2
140	0	1993	Sprague	175	27	646	30	0	1
140	0	1998	Sprague	175	22	8	10	0	0
140	0	2011	Sprague	175	9	2	0	0	0
140	0	2016	Sprague	175	4	1	3	0	0
270	0	1998	Schlumberger	1000	22	25	15	0	0
270	0	2000	Schlumberger	1000	20	18	13	0	0
300	540	2005	Rockwell	800	15	10	11	0	0
450	0	1993	Schlumberger	400	27	188	29	0	0
450	0	1996	Schlumberger	400	24	262	41	0	0
450	0	1998	Schlumberger	400	22	438	45	0	0
450	0	2013	Schlumberger	400	7	1	0	0	0
452	0	2005	Actaris	400	15	17	14	0	0
470	472	1982	American	425	38	18	11	0	0
470	472	1983	American	425	37	26	15	0	0
470	472	1984	American	425	36	105	24	0	0
470	472	1985	American	425	35	23	25	2	0
470	472	1987	American	425	33	112	56	2	0
470	472	1990	American	425	30	25	14	0	0
470	472	1992	American	425	28	141	28	0	0
470	472	1993	American	425	27	61	37	6	0
470	472	1996	American	425	24	11	12	1	0
470	472	1999	American	425	21	248	42	0	0
470	472	2001	American	425	19	57	36	2	0
470	472	2003	American	425	17	203	37	1	0
470	472	2005	American	425	15	22	15	0	0
470	472	2006	American	425	14	34	36	0	0
470	472	2007	American	425	13	231	24	0	2
470	472	2008	American	425	12	12	11	0	0
470	472	2012	American	425	8	1	0	0	0
470	472	2017	American	425	3	1	0	0	0
471	0	2007	American	425	13	471	82	8	0
471	0	2008	American	425	12	38	36	3	0
471	0	2011	American	425	9	109	8	0	0
471	0	2012	American	425	8	10	0	0	0
475	0	2011	American	630	9	1042	57	1	0
475	0	2012	American	630	8	1438	72	1	0

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
475	0	2013	American	630	7	1490	90	2	0
475	0	2014	American	630	6	1553	66	0	0
475	0	2015	American	630	5	1250	75	2	0
475	0	2016	American	630	4	1637	35	1	0
475	0	2017	American	630	3	1693	34	2	0
475	0	2018	American	630	2	4705	53	2	1
475	0	2019	American	630	1	3013	21	0	0
480	486	1992	American	800	28	23	17	0	0
480	486	1993	American	800	27	28	30	2	2
480	486	1995	American	800	25	16	13	0	2
480	486	1996	American	800	24	7	6	0	0
480	486	2001	American	800	19	12	12	1	0
485	0	1997	American	800	23	8	7	0	0
485	0	2011	American	800	9	1	0	0	0
485	0	2016	American	800	4	1	0	0	0
487	0	2017	American	800	3	58	2	0	0
487	0	2018	American	800	2	196	6	0	0
487	0	2019	American	800	1	322	6	0	0
500	502	1998	American	1000	22	84	46	7	0
500	502	2001	American	1000	19	11	9	1	1
500	502	2002	American	1000	18	36	27	1	1
505	507	1981	American	1000	39	8	8	0	1
505	507	2008	American	1000	12	297	69	11	0
505	507	2011	American	1000	9	366	43	2	0
505	507	2012	American	1000	8	390	43	2	0
505	507	2013	American	1000	7	379	33	0	0
505	507	2014	American	1000	6	434	38	0	0
505	507	2015	American	1000	5	361	25	0	0
505	507	2016	American	1000	4	522	33	1	0
505	507	2017	American	1000	3	201	9	0	0
505	507	2018	American	1000	2	351	14	1	0
505	507	2019	American	1000	1	312	10	1	0
510	515	1974	Rockwell	310	46	23	24	0	4
510	515	1976	Rockwell	310	44	264	47	2	3
510	515	1978	Rockwell	310	42	96	48	1	3
510	515	1983	Rockwell	310	37	106	36	1	0
510	515	1984	Rockwell	310	36	15	15	1	1
510	515	1987	Rockwell	310	33	206	51	2	4
510	515	1989	Rockwell	310	31	84	31	1	1
510	515	1991	Rockwell	310	29	208	24	0	1

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
510	515	1993	Rockwell	310	27	94	46	4	2
510	515	1996	Rockwell	310	24	18	23	0	1
510	515	2011	Rockwell	310	9	1	0	0	0
510	515	2013	Rockwell	310	7	1	0	0	0
520	0	1978	Rockwell	415	42	35	15	0	0
520	0	1979	Rockwell	415	41	72	33	1	1
520	0	1982	Rockwell	415	38	33	16	0	0
520	0	1991	Rockwell	415	29	71	24	0	0
520	0	1996	Rockwell	415	24	95	48	2	1
520	0	2000	Rockwell	415	20	84	43	7	0
520	0	2005	Rockwell	415	15	46	20	0	0
520	0	2011	Rockwell	415	9	1	0	0	0
520	0	2017	Rockwell	415	3	1	0	0	0
520	0	2018	Rockwell	415	2	1	0	0	0
520	0	2019	Rockwell	415	1	1	0	0	0
555	0	1981	American	310	39	27	23	1	1
555	0	1986	American	310	34	84	32	1	0
555	0	1987	American	310	33	31	38	2	1
555	0	1989	American	310	31	14	27	2	0
555	0	2012	American	310	8	1	0	0	0
560	0	1986	American	250	34	6150	211	4	0
560	0	1987	American	250	33	428	25	0	0
560	0	1988	American	250	32	3129	92	1	1
560	0	1989	American	250	31	6952	241	3	5
560	0	1990	American	250	30	6251	202	3	6
560	0	1991	American	250	29	5520	202	4	3
560	0	1992	American	250	28	4777	102	2	2
560	0	1993	American	250	27	4050	106	2	1
560	0	1995	American	250	25	8156	193	10	1
560	0	1996	American	250	24	11041	236	9	3
560	0	1998	American	250	22	14378	235	30	3
560	0	1999	American	250	21	11207	156	9	1
560	0	2000	American	250	20	11207	216	6	1
560	0	2001	American	250	19	9384	160	2	2
560	0	2002	American	250	18	8474	116	5	0
560	0	2003	American	250	17	431	68	1	1
560	0	2005	American	250	15	76	34	1	1
560	0	2006	American	250	14	614	51	1	0
560	0	2007	American	250	13	191	25	0	0
560	0	2011	American	250	9	3	0	0	0

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
560	0	2012	American	250	8	6	0	0	0
560	0	2013	American	250	7	3	0	0	0
560	0	2014	American	250	6	5	2	0	0
560	0	2015	American	250	5	1	8	0	0
560	0	2017	American	250	3	1	14	0	0
560	0	2018	American	250	2	3	14	1	0
561	0	2006	American	250	14	21404	363	38	1
561	0	2007	American	250	13	21896	421	37	1
561	0	2010	American	250	10	10069	212	6	0
561	0	2011	American	250	9	10624	196	3	0
561	0	2012	American	250	8	11926	183	1	0
561	0	2013	American	250	7	15296	247	1	3
561	0	2014	American	250	6	14679	192	1	0
561	0	2015	American	250	5	17928	216	3	0
561	0	2016	American	250	4	12652	120	0	0
561	0	2017	American	250	3	11813	125	2	1
561	0	2018	American	250	2	9754	84	1	0
561	0	2019	American	250	1	14604	44	0	0
561	0	2020	American	250	0	17	0	0	0
562	0	2017	American	250	3	22	0	0	0
562	0	2018	American	250	2	695	0	0	0
562	0	2019	American	250	1	1377	1	0	0
570	0	1989	Rockwell	275	31	744	41	1	0
570	0	1990	Rockwell	275	30	5367	125	11	3
570	0	1993	Rockwell	275	27	61	31	1	0
570	0	1995	Rockwell	275	25	6477	121	8	2
570	0	1996	Rockwell	275	24	7651	142	4	1
570	0	1997	Rockwell	275	23	2355	41	1	0
570	0	1999	Rockwell	275	21	10484	181	27	2
570	0	2000	Rockwell	275	20	8465	115	19	1
570	0	2001	Rockwell	275	19	8670	124	4	1
570	0	2002	Rockwell	275	18	10778	165	3	0
570	0	2003	Rockwell	275	17	19806	269	6	2
570	0	2004	Rockwell	275	16	3592	55	0	0
570	0	2005	Rockwell	275	15	12	10	0	0
570	0	2011	Rockwell	275	9	1	0	0	0
570	0	2012	Rockwell	275	8	3	1	0	0
570	0	2013	Rockwell	275	7	1	0	0	0
570	0	2014	Rockwell	275	6	2	0	0	0
570	0	2016	Rockwell	275	4	2	2	0	0

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
570	0	2017	Rockwell	275	3	3	3	0	0
570	0	2018	Rockwell	275	2	2	2	0	0
572	0	2004	Sensus	275	16	13900	201	16	2
572	0	2005	Sensus	275	15	24631	363	51	0
572	0	2008	Sensus	275	12	38	38	1	0
572	0	2011	Sensus	275	9	86	2	0	0
572	0	2012	Sensus	275	8	4	0	0	0
572	0	2013	Sensus	275	7	1	0	0	0
572	0	2014	Sensus	275	6	1	0	0	0
572	0	2015	Sensus	275	5	2	1	0	0
572	0	2016	Sensus	275	4	3	0	0	0
585	0	1992	Sprague	250	28	2093	64	0	0
585	0	1993	Sprague	250	27	3814	114	1	0
585	0	1994	Sprague	250	26	1645	49	1	1
585	0	1995	Sprague	250	25	1512	38	0	0
585	0	1996	Sprague	250	24	4409	108	1	0
585	0	1997	Sprague	250	23	5901	121	1	1
585	0	1998	Sprague	250	22	5388	139	0	1
585	0	1999	Sprague	250	21	243	23	0	0
585	0	2000	Sprague	250	20	36	29	2	0
585	0	2001	Sprague	250	19	49	17	0	0
585	0	2002	Sprague	250	18	44	16	0	0
585	0	2014	Sprague	250	6	2	0	0	0
590	0	1989	Lancaster	250	31	1300	77	0	0
590	0	1990	Lancaster	250	30	1311	55	0	1
590	0	1991	Lancaster	250	29	1707	73	1	0
590	0	1992	Lancaster	250	28	2651	87	1	1
590	0	1993	Lancaster	250	27	2823	72	1	0
590	0	1994	Lancaster	250	26	4350	172	10	5
590	0	1995	Lancaster	250	25	4802	145	7	11
590	0	1996	Lancaster	250	24	26	21	0	0
590	0	1997	Lancaster	250	23	2112	46	0	3
590	0	1998	Lancaster	250	22	28	14	0	0
590	0	2011	Lancaster	250	9	1	0	0	0
590	0	2016	Lancaster	250	4	1	2	0	0
590	0	2019	Lancaster	250	1	1	1	0	0
595	600	2000	Schlumberger	250	20	3174	316	18	12
595	600	2001	Schlumberger	250	19	3766	180	3	1
595	600	2002	Schlumberger	250	18	3240	180	0	4
595	600	2012	Schlumberger	250	8	1	0	0	0

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
595	600	2016	Schlumberger	250	4	1	1	0	0
602	0	2016	Itron	250	4	4360	35	0	0
602	0	2017	Itron	250	3	4587	42	0	0
602	0	2018	Itron	250	2	8182	52	2	0
602	0	2019	Itron	250	1	11485	30	0	0
602	0	2020	Itron	250	0	20	0	0	0
125	0	1984	Rockwell	200	36	2082	87	12	1
480	486	1989	American	800	31	24	13	0	0
510	515	1992	Rockwell	310	28	116	46	2	5
560	0	1994	American	250	26	6126	121	7	1
300	540	1996	Rockwell	800	24	20	15	0	2
480	486	1990	American	800	30	22	12	0	0
505	507	2007	American	1000	13	339	72	11	0
510	515	1990	Rockwell	310	30	201	61	6	3
561	0	2005	American	250	15	1636	88	13	0
120	0	1983	Rockwell	175	37	1329	92	11	2
125	0	1992	Rockwell	200	28	604	41	1	0
130	0	1992	American	175	28	1388	91	10	0
130	0	1994	American	175	26	2599	89	11	0
140	0	1994	Sprague	175	26	563	46	1	2
270	0	2001	Schlumberger	1000	19	33	28	2	0
272	0	2004	Actaris	1000	16	7	8	0	0
572	0	2009	Sensus	275	11	744	41	0	0
470	472	1986	American	425	34	53	17	0	0
485	0	1984	American	800	36	54	29	1	1
520	0	1987	Rockwell	415	33	38	22	1	2
555	0	1980	American	310	40	58	36	4	0
585	0	1991	Sprague	250	29	736	24	0	0
470	472	1994	American	425	26	215	36	1	1
570	0	1992	Rockwell	275	28	128	55	5	0
570	0	1994	Rockwell	275	26	4979	119	8	0
120	0	1972	Rockwell	175	48	814	78	10	2
125	0	1999	Rockwell	200	21	135	22	0	0
470	472	1997	American	425	23	280	74	5	0
120	0	1976	Rockwell	175	44	1062	83	7	2
120	0	1995	Rockwell	175	25	312	75	5	0
125	0	1986	Rockwell	200	34	335	68	3	0
125	0	1990	Rockwell	200	30	289	70	10	0
140	0	1997	Sprague	175	23	459	25	0	0
570	0	1991	Rockwell	275	29	2829	92	8	0

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
590	0	1999	Lancaster	250	21	141	23	0	0
595	600	2003	Schlumberger	250	17	51	18	0	0
595	600	2004	Schlumberger	250	16	21	13	0	0
120	0	1969	Rockwell	175	51	168	66	4	0
120	0	1986	Rockwell	175	34	1253	89	5	3
140	0	1977	Sprague	175	43	292	39	0	4
475	0	2010	American	630	10	619	56	2	0
570	0	1998	Rockwell	275	22	5340	115	11	1
585	0	1988	Sprague	250	32	178	22	0	0
585	0	2004	Sprague	250	16	47	18	0	0
120	0	1973	Rockwell	175	47	598	81	10	0
120	0	1997	Rockwell	175	23	157	37	1	0
120	0	1998	Rockwell	175	22	70	19	0	0
130	0	1985	American	175	35	2013	88	11	2
480	486	2002	American	800	18	21	12	0	0
560	0	1985	American	250	35	1397	74	3	1
140	0	1978	Sprague	175	42	242	30	0	3
140	0	1980	Sprague	175	40	273	60	4	7
510	515	1981	Rockwell	310	39	188	21	0	1
510	515	1986	Rockwell	310	34	16	10	0	0
520	0	1981	Rockwell	415	39	220	23	0	1
555	0	1997	American	310	23	21	18	2	1
590	0	1988	Lancaster	250	32	73	19	0	0
120	0	1968	Rockwell	175	52	57	40	2	0
125	0	1988	Rockwell	200	32	343	82	4	0
450	0	2005	Schlumberger	400	15	7	6	0	0
470	472	2000	American	425	20	385	39	1	0
520	0	1988	Rockwell	415	32	42	15	0	1
452	0	2003	Actaris	400	17	77	37	1	1
470	472	1998	American	425	22	136	56	5	0
485	0	1981	American	800	39	19	16	0	3
510	515	1977	Rockwell	310	43	138	35	1	0
520	0	1992	Rockwell	415	28	49	27	1	1
450	0	2003	Schlumberger	400	17	16	10	0	0
470	472	1995	American	425	25	76	23	0	0
470	472	2002	American	425	18	384	76	3	0
470	472	2004	American	425	16	49	32	1	0
471	0	2010	American	425	10	83	22	0	0
510	515	1982	Rockwell	310	38	39	34	1	2
520	0	1980	Rockwell	415	40	55	29	1	0

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
520	0	1997	Rockwell	415	23	44	16	0	0
555	0	1983	American	310	37	79	41	2	0
555	0	1984	American	310	36	162	61	2	2
452	0	2004	Actaris	400	16	401	73	4	3
450	0	1999	Schlumberger	400	21	91	20	0	0
520	0	2003	Rockwell	415	17	141	21	0	0
555	0	1985	American	310	35	89	32	1	0
450	0	1997	Schlumberger	400	23	54	18	0	0
520	0	1994	Rockwell	415	26	83	19	0	1
510	515	1973	Rockwell	310	47	62	33	1	4
470	472	1989	American	425	31	18	19	2	0
510	515	1979	Rockwell	310	41	118	49	5	7
510	515	1994	Rockwell	310	26	29	14	0	0
520	0	1977	Rockwell	415	43	39	16	0	0
520	0	2004	Rockwell	415	16	60	38	3	0
					Totals	**699,268**	**22,537**	**1,209**	**363**

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Appendix B
Meter Families Not Conforming (To Be Removed Over 4 Years)

Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	Determination
120	0	2010	Rockwell	175	10	1	Small Family
125	0	2009	Rockwell	200	11	3	Small Family
130	0	1972	American	175	48	2661	Determined
130	0	1978	American	175	42	1534	Determined
130	0	2019	American	175	1	1	Small Family
140	0	2009	Sprague	175	11	2	Small Family
470	472	2009	American	425	11	4	Small Family
470	472	2010	American	425	10	2	Small Family
470	472	2019	American	425	1	2	Small Family
471	0	2009	American	425	11	3	Small Family
475	0	2002	American	630	18	1	Small Family
485	0	1980	American	800	40	17	Determined
505	507	1980	American	1000	40	6	Small Family
510	515	2009	Rockwell	310	11	1	Small Family
510	515	2010	Rockwell	310	10	1	Small Family
520	0	2009	Rockwell	415	11	3	Small Family
555	0	2009	American	310	11	1	Small Family
560	0	2010	American	250	10	2	Small Family
560	0	2019	American	250	1	4	Determined
561	0	2008	American	250	12	22887	Determined
570	0	2019	Rockwell	275	1	4	Determined
585	0	2009	Sprague	250	11	5	Small Family
590	0	2009	Lancaster	250	11	2	Small Family
590	0	2010	Lancaster	250	10	1	Small Family
602	0	1982	Itron	250	38	1	Small Family
485	0	1996	American	800	24	6	Small Family
505	507	2009	American	1000	11	270	Determined
480	486	1991	American	800	29	37	Determined
500	502	2003	American	1000	17	14	Determined
130	0	2009	American	175	10	19	Sampling Limit
450	0	2004	Schlumberger	400	15	8	Sampling Limit
510	515	1997	Rockwell	310	22	9	Sampling Limit
520	0	1983	Rockwell	415	36	17	Sampling Limit
570	0	2009	Rockwell	275	10	16	Sampling Limit
572	0	2010	Sensus	275	10	15	Sampling Limit
585	0	2003	Sprague	250	16	12	Sampling Limit

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	Determination
555	0	1994	American	310	26	6	Determined
470	472	1988	American	425	32	39	Determined
470	472	1991	American	425	29	15	Determined
520	0	1995	Rockwell	415	25	266	Determined
					Total	**27204**	

Staff/906
Dlouhy/28

Oregon Public Utility Commission

Docket No. UG 490

e-FILING REPORT COVER SHEET

COMPANY NAME: NW Natural

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☐ No ☐ Yes If yes, submit a redacted public version (or a cover letter) by email. Submit the confidential information as directed in OAR 860-001-0070 or the terms of an applicable protective order.

Select report type: ☐ RE (Electric) ☐ RG (Gas) ☐ RW (Water) ☐ RT (Telecommunications)
☐ RO (Other, for example, industry safety information)

Did you previously file a similar report? ☐ No ☐ Yes, report docket number: RG 41

Report is required by: ☐ OAR
☐ Statute
☐ Order
Note: A one-time submission required by an order is a compliance filing and not a report (file compliance in the applicable docket)
☑ Other At request of Commission Staff
(For example, federal regulations, or requested by Staff)

Is this report associated with a specific docket/case? ☐ No ☐ Yes, docket number: RG 41

List Key Words for this report. We use these to improve search results.

Meter Sampling for 2020, NW Natural

Send the completed Cover Sheet and the Report in an email addressed to PUC.FilingCenter@puc.oregon.gov

Send confidential information, voluminous reports, or energy utility Results of Operations Reports to PUC Filing Center, PO Box 1088, Salem, OR 97308-1088 or by delivery service to 201 High Street SE Suite 100, Salem, OR 97301.

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Docket No. UG 490

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March 4, 2022

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Post Office Box 1088
Salem, Oregon 97308-1088

Re: RG 41: Meter Sampling Program Report for 2021

At the request of Commission Staff, Northwest Natural Gas Company, dba NW Natural, submits herewith its 2021 Meter Sampling Program Report.

As required by our Meter Testing Standards and Procedures document, the accuracies of all operating families of diaphragm meters with capacities 1000 ft^3/hr and below have been statistically analyzed for the year 2021. This analysis utilized all relevant meter tests conducted during the five calendar years between January 1, 2016 and December 31, 2021. The results of this analysis are as follows:

- As of December 31, 2021, 787,474 meters are installed and covered under the Meter Sampling Program. Of these, 735,372 meters, forming 368 distinct meter families, are conforming. The remaining 52,102 are non-conforming and are scheduled for replacement.
- Over the course of 2021, the company tested 5,790 meters. Over the five-year period of 2016 through 2021, the company had a total of 31,609 meter samples from which to base its results.
- 357 meter families either had sufficient meter samples to establish statistical confidence in their accuracy, or are so new that they do not yet require minimum sampling. These meter families amount to 719,174 meters, or 91 percent of the total meter population. The performances of these families are exhibited in Appendix A.
- 12 new meter families were added in 2021. 14 meter families were removed from service due to small family size, during the normal course of business. 4 meter families were removed from service due to the number of supplementary samples required exceeding 50% of the family size, with a family size less than 100 meters.
- 30 meter families, consisting of a total of 35,677 meters, are not conforming. Due to the number of meters requiring change-out (4.5% of the total population), these meters have been put on the list to be removed over the course of the next 4 years, by December 2025, per Meter Sampling Program (MSP) guidelines outlined in NW Natural Engineering Procedure Z-1. The performance of these families is exhibited in Appendix B.
- A further breakdown of the non-conforming meter families and associated meters described above are as follows, the performance of these families is exhibited in Appendix B:
    - 12 meter families, totaling 35,511 meters had sufficient meter tests available to have their accuracy determined statistically and determined non-conforming.

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  - 14 meter families, totaling 41 meters, will be removed from service due to their small population size and age.
  - 4 meter families, totaling 125 meters, will be removed from service due to a family size less than 100 meters, and sampling requirements exceeding 50% of the total family population.
- Compared to the results above, the Year 2020 report resulted in 27,204 meters being put on the list for removal by December 2024.
- Regarding the planned 4-year removal of meters determined non-conforming in 2019 and 2020, the following meters remain:
  - PCC Year 2020 (for removal 2020 to 2023): 5,906 remain out of 42,046 determined
  - PCC Year 2021 (for removal 2021 to 2024): 14,113 remain out of 27,204 determined
  - PCC Year 2022 (for removal 2022 to 2025): 32,083 remain out of 35,677 determined

If you have any questions or comments, please contact me at 503-610-7494.

Sincerely,
/s/ *Michael J. McKenzie*

Michael J. McKenzie, PE
Gas Measurement and Station Design Engineering Supervisor

cc:

Andy Fortier	Dave Weber
Jon Huddleston	Kim Heiting
Joe Karney	Dan Kizer

Docket No. UG 490

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Appendix A
Meter Families in Conformance

Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
120	0	1968	Rockwell	175	53	55	41	2	0
120	0	1969	Rockwell	175	52	166	66	5	0
120	0	1972	Rockwell	175	49	805	83	10	2
120	0	1973	Rockwell	175	48	595	81	10	1
120	0	1974	Rockwell	175	47	2501	176	15	3
120	0	1975	Rockwell	175	46	1726	113	15	1
120	0	1976	Rockwell	175	45	1049	89	7	3
120	0	1978	Rockwell	175	43	1401	103	6	4
120	0	1979	Rockwell	175	42	1561	115	8	4
120	0	1982	Rockwell	175	39	1140	90	14	1
120	0	1983	Rockwell	175	38	1293	108	14	2
120	0	1984	Rockwell	175	37	1410	91	15	1
120	0	1985	Rockwell	175	36	1882	104	12	2
120	0	1987	Rockwell	175	34	2145	139	10	2
120	0	1988	Rockwell	175	33	2101	117	8	5
120	0	1989	Rockwell	175	32	3385	181	11	6
120	0	1990	Rockwell	175	31	3450	156	15	5
120	0	1991	Rockwell	175	30	3716	208	6	8
120	0	1992	Rockwell	175	29	6535	312	10	9
120	0	1993	Rockwell	175	28	2577	131	7	3
120	0	1994	Rockwell	175	27	1329	69	3	4
120	0	1996	Rockwell	175	25	720	86	3	0
120	0	2012	Rockwell	175	9	1	0	0	0
120	0	2013	Rockwell	175	8	1	0	0	0
120	0	2014	Rockwell	175	7	1	0	0	0
125	0	1978	Rockwell	200	43	1527	112	3	1
125	0	1980	Rockwell	200	41	1778	99	12	0
125	0	1981	Rockwell	200	40	2426	105	13	0
125	0	1982	Rockwell	200	39	3020	137	8	0
125	0	1983	Rockwell	200	38	1713	104	5	1
125	0	1984	Rockwell	200	37	2042	108	11	1
125	0	1986	Rockwell	200	35	333	74	3	0
125	0	1988	Rockwell	200	33	342	88	4	0
125	0	1991	Rockwell	200	30	673	49	0	0
125	0	1992	Rockwell	200	29	594	48	1	0
125	0	1993	Rockwell	200	28	469	74	7	2
125	0	1994	Rockwell	200	27	383	78	6	1

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
125	0	1995	Rockwell	200	26	69	46	5	0
125	0	1996	Rockwell	200	25	227	30	0	0
125	0	1999	Rockwell	200	22	132	23	0	0
125	0	2017	Rockwell	200	4	1	3	0	0
125	0	2019	Rockwell	200	2	1	3	0	0
130	0	1973	American	175	48	710	82	11	1
130	0	1975	American	175	46	23	14	0	0
130	0	1977	American	175	44	3158	141	13	4
130	0	1979	American	175	42	6200	275	13	3
130	0	1980	American	175	41	5995	289	15	3
130	0	1984	American	175	37	4634	224	23	6
130	0	1985	American	175	36	2002	103	10	2
130	0	1986	American	175	35	3875	166	17	2
130	0	1987	American	175	34	5766	208	28	2
130	0	1988	American	175	33	3033	152	18	2
130	0	1989	American	175	32	3162	124	18	4
130	0	1991	American	175	30	4758	166	24	5
130	0	1994	American	175	27	2569	96	13	0
130	0	1996	American	175	25	1031	41	1	1
130	0	1997	American	175	24	197	53	1	1
130	0	2013	American	175	8	1	0	0	0
130	0	2014	American	175	7	3	0	0	0
130	0	2016	American	175	5	2	7	0	0
130	0	2020	American	175	1	1	13	1	0
140	0	1968	Sprague	175	53	957	78	0	14
140	0	1970	Sprague	175	51	329	38	0	3
140	0	1971	Sprague	175	50	935	71	0	7
140	0	1972	Sprague	175	49	145	26	0	2
140	0	1973	Sprague	175	48	2780	172	3	7
140	0	1974	Sprague	175	47	605	34	0	2
140	0	1975	Sprague	175	46	697	44	0	0
140	0	1976	Sprague	175	45	1057	55	2	4
140	0	1977	Sprague	175	44	289	36	0	4
140	0	1978	Sprague	175	43	240	30	0	2
140	0	1979	Sprague	175	42	126	37	1	1
140	0	1980	Sprague	175	41	270	61	4	7
140	0	1981	Sprague	175	40	610	42	0	1
140	0	1982	Sprague	175	39	549	58	2	3
140	0	1983	Sprague	175	38	786	56	0	3
140	0	1985	Sprague	175	36	1102	76	1	5

Docket No. UG 490

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
140	0	1986	Sprague	175	35	929	54	1	3
140	0	1987	Sprague	175	34	2870	153	0	13
140	0	1988	Sprague	175	33	718	73	2	3
140	0	1989	Sprague	175	32	743	37	0	4
140	0	1990	Sprague	175	31	995	56	0	1
140	0	1991	Sprague	175	30	431	36	0	3
140	0	1992	Sprague	175	29	549	33	0	1
140	0	1993	Sprague	175	28	624	40	0	4
140	0	1994	Sprague	175	27	554	52	1	2
140	0	1997	Sprague	175	24	454	28	0	0
140	0	1998	Sprague	175	23	8	9	0	0
140	0	2016	Sprague	175	5	1	3	0	0
270	0	2000	Schlumberger	1000	21	17	13	0	0
270	0	2001	Schlumberger	1000	20	25	34	2	0
272	0	2004	Actaris	1000	17	7	9	1	0
450	0	1993	Schlumberger	400	28	180	29	0	0
450	0	1996	Schlumberger	400	25	254	32	0	0
450	0	1998	Schlumberger	400	23	426	45	0	1
450	0	2003	Schlumberger	400	18	16	13	0	0
450	0	2013	Schlumberger	400	8	1	0	0	0
452	0	2003	Actaris	400	18	77	39	1	0
470	472	1982	American	425	39	16	12	0	0
470	472	1984	American	425	37	102	20	0	0
470	472	1985	American	425	36	22	23	2	0
470	472	1986	American	425	35	51	18	0	0
470	472	1987	American	425	34	107	59	2	0
470	472	1989	American	425	32	18	20	2	0
470	472	1992	American	425	29	138	21	0	0
470	472	1995	American	425	26	75	21	0	0
470	472	1996	American	425	25	9	12	1	1
470	472	1997	American	425	24	275	73	5	0
470	472	1998	American	425	23	135	55	6	0
470	472	1999	American	425	22	243	28	0	0
470	472	2000	American	425	21	380	47	1	0
470	472	2004	American	425	17	46	38	4	1
470	472	2006	American	425	15	34	35	0	0
470	472	2008	American	425	13	11	12	0	0
470	472	2012	American	425	9	1	0	0	0
470	472	2017	American	425	4	1	0	0	0
471	0	2007	American	425	14	464	79	8	0

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
471	0	2008	American	425	13	37	37	3	0
471	0	2012	American	425	9	10	0	0	0
475	0	2011	American	630	10	1029	61	1	0
475	0	2012	American	630	9	1419	80	1	0
475	0	2013	American	630	8	1472	90	2	0
475	0	2014	American	630	7	1531	67	0	1
475	0	2015	American	630	6	1244	62	2	0
475	0	2016	American	630	5	1617	51	1	0
475	0	2017	American	630	4	1678	47	2	0
475	0	2018	American	630	3	4664	86	2	1
475	0	2019	American	630	2	2980	59	0	0
475	0	2020	American	630	1	899	9	0	0
480	486	1989	American	800	32	22	13	0	0
480	486	2002	American	800	19	20	12	0	0
485	0	1981	American	800	40	19	17	0	3
485	0	1984	American	800	37	50	30	1	1
485	0	2016	American	800	5	1	0	0	0
487	0	2017	American	800	4	58	2	0	0
487	0	2018	American	800	3	193	9	0	0
487	0	2019	American	800	2	318	8	0	0
487	0	2020	American	800	1	237	5	0	0
487	0	2021	American	800	0	1	0	0	0
505	507	1981	American	1000	40	7	9	0	2
505	507	2008	American	1000	13	286	70	11	0
505	507	2012	American	1000	9	379	43	2	0
505	507	2013	American	1000	8	372	34	0	0
505	507	2014	American	1000	7	428	34	0	0
505	507	2015	American	1000	6	354	26	0	0
505	507	2016	American	1000	5	516	38	1	0
505	507	2017	American	1000	4	199	11	0	0
505	507	2018	American	1000	3	345	19	2	0
505	507	2019	American	1000	2	300	19	1	0
505	507	2020	American	1000	1	15	2	1	0
510	515	1973	Rockwell	310	48	62	30	1	3
510	515	1974	Rockwell	310	47	22	22	0	4
510	515	1976	Rockwell	310	45	241	50	2	4
510	515	1978	Rockwell	310	43	93	46	1	3
510	515	1979	Rockwell	310	42	116	48	5	7
510	515	1982	Rockwell	310	39	37	40	1	3
510	515	1983	Rockwell	310	38	103	36	1	0

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
510	515	1984	Rockwell	310	37	15	15	1	1
510	515	1986	Rockwell	310	35	15	11	0	0
510	515	1987	Rockwell	310	34	198	54	2	3
510	515	1991	Rockwell	310	30	202	22	0	1
510	515	1992	Rockwell	310	29	114	39	1	4
510	515	1994	Rockwell	310	27	29	14	0	0
510	515	1996	Rockwell	310	25	18	20	0	1
510	515	2013	Rockwell	310	8	1	0	0	0
520	0	1978	Rockwell	415	43	30	15	0	0
520	0	1980	Rockwell	415	41	54	32	1	0
520	0	1982	Rockwell	415	39	32	16	0	0
520	0	1987	Rockwell	415	34	37	20	0	2
520	0	1988	Rockwell	415	33	42	15	0	1
520	0	1994	Rockwell	415	27	82	19	0	1
520	0	1996	Rockwell	415	25	93	48	2	1
520	0	1997	Rockwell	415	24	43	18	0	0
520	0	2000	Rockwell	415	21	82	43	7	0
520	0	2004	Rockwell	415	17	59	40	4	0
520	0	2017	Rockwell	415	4	1	0	0	0
520	0	2018	Rockwell	415	3	1	0	0	0
520	0	2019	Rockwell	415	2	1	0	0	0
555	0	1980	American	310	41	56	38	4	0
555	0	1981	American	310	40	27	19	1	1
555	0	1984	American	310	37	159	59	2	2
555	0	1987	American	310	34	30	33	2	1
555	0	2012	American	310	9	1	0	0	0
560	0	1985	American	250	36	1390	73	2	1
560	0	1986	American	250	35	6030	251	6	3
560	0	1988	American	250	33	3078	105	2	0
560	0	1989	American	250	32	6813	279	5	5
560	0	1990	American	250	31	6126	236	6	6
560	0	1991	American	250	30	5412	231	4	4
560	0	1992	American	250	29	4722	118	2	3
560	0	1993	American	250	28	3984	124	0	2
560	0	1994	American	250	27	6021	157	8	1
560	0	1995	American	250	26	8019	217	13	4
560	0	1996	American	250	25	10895	297	13	4
560	0	1998	American	250	23	14194	292	38	3
560	0	1999	American	250	22	11081	195	14	1
560	0	2000	American	250	21	11087	247	6	1

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
560	0	2001	American	250	20	9293	198	3	2
560	0	2002	American	250	19	8388	147	6	0
560	0	2003	American	250	18	422	61	1	1
560	0	2006	American	250	15	602	56	1	0
560	0	2007	American	250	14	183	26	0	0
560	0	2012	American	250	9	6	0	0	0
560	0	2013	American	250	8	3	0	0	0
560	0	2014	American	250	7	5	0	0	0
560	0	2015	American	250	6	1	1	0	0
560	0	2018	American	250	3	3	14	1	0
561	0	2006	American	250	15	21165	454	59	1
561	0	2007	American	250	14	21587	536	70	2
561	0	2010	American	250	11	9912	310	7	1
561	0	2011	American	250	10	10450	317	4	0
561	0	2012	American	250	9	11754	295	2	2
561	0	2013	American	250	8	15144	335	2	5
561	0	2014	American	250	7	14508	295	3	1
561	0	2015	American	250	6	17781	295	0	0
561	0	2016	American	250	5	12582	186	0	0
561	0	2017	American	250	4	11750	174	2	1
561	0	2018	American	250	3	9707	114	2	1
561	0	2019	American	250	2	14566	104	2	0
561	0	2020	American	250	1	10701	46	9	0
561	0	2021	American	250	0	5	0	0	0
562	0	2017	American	250	4	22	0	0	0
562	0	2018	American	250	3	695	0	0	0
562	0	2020	American	250	1	996	0	0	0
570	0	1990	Rockwell	275	31	5274	174	8	3
570	0	1991	Rockwell	275	30	2825	108	9	0
570	0	1992	Rockwell	275	29	127	56	5	0
570	0	1993	Rockwell	275	28	61	30	1	0
570	0	1994	Rockwell	275	27	4953	137	9	0
570	0	1995	Rockwell	275	26	6370	167	10	4
570	0	1996	Rockwell	275	25	7563	173	3	1
570	0	1997	Rockwell	275	24	2330	51	1	0
570	0	1998	Rockwell	275	23	5327	136	13	1
570	0	1999	Rockwell	275	22	10380	196	26	1
570	0	2000	Rockwell	275	21	8363	161	18	1
570	0	2001	Rockwell	275	20	8593	161	6	0
570	0	2002	Rockwell	275	19	10704	194	3	0

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
570	0	2003	Rockwell	275	18	19571	408	5	2
570	0	2004	Rockwell	275	17	3551	71	0	0
570	0	2012	Rockwell	275	9	4	1	0	0
570	0	2013	Rockwell	275	8	1	0	0	0
570	0	2014	Rockwell	275	7	2	0	0	0
570	0	2016	Rockwell	275	5	2	2	0	0
570	0	2017	Rockwell	275	4	3	3	0	0
570	0	2018	Rockwell	275	3	2	2	0	0
572	0	2004	Sensus	275	17	13742	258	25	2
572	0	2008	Sensus	275	13	37	38	1	0
572	0	2009	Sensus	275	12	735	50	1	0
572	0	2012	Sensus	275	9	3	1	0	0
572	0	2013	Sensus	275	8	1	0	0	0
572	0	2014	Sensus	275	7	1	0	0	0
572	0	2015	Sensus	275	6	2	0	0	0
572	0	2016	Sensus	275	5	3	0	0	0
572	0	2020	Sensus	275	1	9458	24	2	0
572	0	2021	Sensus	275	0	15	0	0	0
585	0	1992	Sprague	250	29	2049	91	0	1
585	0	1993	Sprague	250	28	3762	135	1	0
585	0	1994	Sprague	250	27	1625	56	0	1
585	0	1996	Sprague	250	25	4358	133	1	0
585	0	1997	Sprague	250	24	5821	163	2	2
585	0	1998	Sprague	250	23	5309	173	0	1
585	0	2001	Sprague	250	20	49	17	0	0
585	0	2002	Sprague	250	19	43	16	0	0
585	0	2004	Sprague	250	17	47	17	0	0
585	0	2014	Sprague	250	7	2	0	0	0
590	0	1989	Lancaster	250	32	1278	78	0	0
590	0	1990	Lancaster	250	31	1290	66	0	1
590	0	1991	Lancaster	250	30	1679	82	1	0
590	0	1992	Lancaster	250	29	2603	114	1	1
590	0	1993	Lancaster	250	28	2788	82	1	0
590	0	1994	Lancaster	250	27	4273	203	11	5
590	0	1995	Lancaster	250	26	4723	168	11	14
590	0	1996	Lancaster	250	25	26	21	0	0
590	0	1997	Lancaster	250	24	2085	60	1	3
590	0	1999	Lancaster	250	22	140	24	0	0
590	0	2016	Lancaster	250	5	1	2	0	0
590	0	2019	Lancaster	250	2	1	1	0	0

Docket No. UG 490

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
595	600	2000	Schlumberger	250	21	3078	341	16	12
595	600	2001	Schlumberger	250	20	3711	190	4	1
595	600	2002	Schlumberger	250	19	3200	166	0	5
595	600	2003	Schlumberger	250	18	47	20	0	0
595	600	2004	Schlumberger	250	17	21	13	0	0
595	600	2012	Schlumberger	250	9	1	0	0	0
595	600	2016	Schlumberger	250	5	1	1	0	0
595	600	2019	Schlumberger	250	2	1	3	0	0
602	0	2016	Itron	250	5	4339	55	0	0
602	0	2017	Itron	250	4	4561	66	0	1
602	0	2018	Itron	250	3	8145	76	2	0
602	0	2019	Itron	250	2	11507	76	0	0
602	0	2020	Itron	250	1	21437	51	0	0
602	0	2020	Itron	250	1	21437	51	0	0
602	0	2021	Itron	250	0	2	0	0	0
603	0	2020	Itron	400	1	438	2	0	0
555	0	1983	American	310	38	78	40	2	0
120	0	1980	Rockwell	175	41	983	81	8	1
140	0	1984	Sprague	175	37	673	42	0	5
560	0	1987	American	250	34	419	24	0	0
120	0	1986	Rockwell	175	35	1238	97	6	3
125	0	1979	Rockwell	200	42	147	37	1	0
452	0	2004	Actaris	400	17	395	73	4	3
570	0	2005	Rockwell	275	16	7	6	0	0
585	0	1991	Sprague	250	30	701	43	1	0
585	0	2000	Sprague	250	21	32	28	2	0
585	0	1988	Sprague	250	33	174	22	0	0
585	0	1995	Sprague	250	26	1474	54	2	1
120	0	1977	Rockwell	175	44	1295	92	5	3
130	0	1992	American	175	29	1353	92	10	0
450	0	1997	Schlumberger	400	24	53	18	0	0
480	486	1990	American	800	31	20	12	0	0
480	486	2001	American	800	20	11	10	1	0
510	515	1981	Rockwell	310	40	182	21	0	1
570	0	1989	Rockwell	275	32	701	71	3	0
125	0	1989	Rockwell	200	32	503	27	0	2
450	0	1999	Schlumberger	400	22	87	20	0	0
470	472	2001	American	425	20	55	36	2	0
470	472	2002	American	425	19	378	76	4	0
500	502	2002	American	1000	19	33	23	1	1

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
510	515	1977	Rockwell	310	44	129	36	1	0
520	0	1981	Rockwell	415	40	213	24	0	2
520	0	2003	Rockwell	415	18	139	21	0	0
585	0	1999	Sprague	250	22	240	23	0	0
120	0	1970	Rockwell	175	51	559	79	10	1
120	0	1997	Rockwell	175	24	133	54	5	1
480	486	1995	American	800	26	15	12	0	2
510	515	1993	Rockwell	310	28	88	22	0	2
120	0	1995	Rockwell	175	26	277	70	8	0
270	0	1998	Schlumberger	1000	23	20	12	0	0
520	0	1979	Rockwell	415	42	66	28	1	2
590	0	1988	Lancaster	250	33	70	20	0	0
520	0	1977	Rockwell	415	44	36	15	0	0
130	0	1971	American	175	50	1001	81	9	0
130	0	1995	American	175	26	470	72	8	0
475	0	2010	American	630	11	584	82	8	0
480	486	1992	American	800	29	21	12	0	0
560	0	2005	American	250	16	57	18	0	0
120	0	1981	Rockwell	175	40	640	80	9	1
470	472	1994	American	425	27	182	59	3	1
471	0	2010	American	425	11	74	31	1	0
505	507	2011	American	1000	10	312	75	6	0
510	515	1989	Rockwell	310	32	75	31	1	0
562	0	2019	American	250	2	1371	5	1	0
470	472	1983	American	425	38	21	12	0	0
510	515	1990	Rockwell	310	31	189	63	5	2
120	0	1998	Rockwell	175	23	45	28	1	1
125	0	1987	Rockwell	200	34	496	68	3	0
520	0	1992	Rockwell	415	29	47	27	1	3
470	472	2007	American	425	14	190	50	2	0
471	0	2011	American	425	10	79	33	1	0
590	0	1998	Lancaster	250	23	16	10	0	0
125	0	1998	Rockwell	200	23	39	35	3	0
520	0	1991	Rockwell	415	30	62	17	0	1
125	0	1990	Rockwell	200	31	282	70	10	0
470	472	2003	American	425	18	139	59	3	0
555	0	1985	American	310	36	74	40	2	0
555	0	1989	American	310	32	8	7	0	0
572	0	2011	Sensus	275	10	65	19	0	0
520	0	2005	Rockwell	415	16	19	26	1	0

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Appendix B
Meter Families Not Conforming (To Be Removed Over 4 Years)

Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	Determination
130	0	1983	American	175	38	2890	Determined
130	0	1990	American	175	31	3041	Determined
130	0	1993	American	175	28	3073	Determined
140	0	2011	Sprague	175	10	2	Small Family
300	540	1996	Rockwell	800	25	18	Determined
470	472	1993	American	425	28	59	Determined
480	486	1993	American	800	28	24	Determined
485	0	2011	American	800	10	1	Small Family
500	502	2001	American	1000	20	10	Determined
505	507	2007	American	1000	14	330	Determined
510	515	2011	Rockwell	310	10	1	Small Family
520	0	2011	Rockwell	415	10	1	Small Family
560	0	2011	American	250	10	3	Small Family
560	0	2020	American	250	1	7	Small Family
561	0	2005	American	250	16	1621	Determined
570	0	2011	Rockwell	275	10	1	Small Family
570	0	2020	Rockwell	275	1	2	Small Family
572	0	2003	Sensus	275	18	1	Small Family
572	0	2005	Sensus	275	16	24364	Determined
590	0	2011	Lancaster	250	10	1	Small Family
480	486	1996	American	800	25	6	Small Family
300	540	2005	Rockwell	800	16	5	Small Family
450	0	2005	Schlumberger	400	16	5	Small Family
485	0	1997	American	800	24	5	Small Family
500	502	1998	American	1000	23	62	Determined
555	0	1986	American	310	35	75	Small Family - Samples > 50%
555	0	1997	American	310	24	19	Determined
470	472	2005	American	425	16	17	Small Family - Samples > 50%
470	472	1990	American	425	31	17	Small Family - Samples > 50%
452	0	2005	Actaris	400	16	16	Small Family - Samples > 50%
					Total	**35677**	

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Dlouhy/41

Oregon Public Utility Commission

Docket No. UG 490

e-FILING REPORT COVER SHEET

COMPANY NAME: NW Natural

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☐ No ☐ Yes If yes, submit a redacted public version (or a cover letter) by email. Submit the confidential information as directed in OAR 860-001-0070 or the terms of an applicable protective order.

Select report type: ☐ RE (Electric) ☐ RG (Gas) ☐ RW (Water) ☐ RT (Telecommunications)
☐ RO (Other, for example, industry safety information)

Did you previously file a similar report? ☐ No ☐ Yes, report docket number: RG 41

Report is required by: ☐ OAR
☐ Statute
☐ Order
Note: A one-time submission required by an order is a compliance filing and not a report (file compliance in the applicable docket)
☑ Other At request of Commission Staff
(For example, federal regulations, or requested by Staff)

Is this report associated with a specific docket/case? ☐ No ☐ Yes, docket number: RG 41

List Key Words for this report. We use these to improve search results.

Meter Sampling for 2020, NW Natural

Send the completed Cover Sheet and the Report in an email addressed to PUC.FilingCenter@state.or.us

Send confidential information, voluminous reports, or energy utility Results of Operations Reports to PUC Filing Center, PO Box 1088, Salem, OR 97308-1088 or by delivery service to 201 High Street SE Suite 100, Salem, OR 97301.

Print

Docket No. UG 490

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February 22, 2023

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Post Office Box 1088
Salem, OR 7308-1088

Re: RG 41: Meter Sampling Program Report for 2022

At the request of Commission Staff, Northwest Natural Gas Company, dba NW Natural, submits herewith its 2022 Meter Sampling Program Report.

As required by our Meter Testing Standards and Procedures document, the accuracies of all operating families of diaphragm meters with capacities 1000 ft^3/hr and below have been statistically analyzed for the year 2022. This analysis utilized all relevant meter tests conducted during the five calendar years between January 1, 2017, and December 31, 2022. The results of this analysis are as follows:

- As of December 31, 2022, 791,368 meters are installed and covered under the Meter Sampling Program. Of these, 695,137 meters, forming 369 distinct meter families, are conforming. The remaining 96,231 meters forming 78 distinct meter families are non-conforming and are scheduled for replacement. 60 non-conforming meter families were identified in prior years and 18 new meter families were identified as non-conforming in 2022. The 96,231 non-conforming meters represent 12 percent of the total meter population.
- Over the course of 2022, the company tested 9,577 meters. Over the five-year period of 2017 through 2022, the company had a total of 37,442 meter samples from which to base its results.
- 369 meter families either had sufficient meter samples to establish statistical confidence in their accuracy, or are new for 2022. These meter families amount to 695,137 meters, or 88 percent of the total meter population. The performances of these families are exhibited in Appendix A.
- 1 meter family, Perf #572, the 2005 Sensus R-275, was previously declared PCC for PCC Year 2022. However, after performing and evaluating the results of 5,569 meter tests in 2021 and 2022, specific delivery lots of these meters were determined to be non-conforming, while other lots remained conforming. Due to this, a population of 6,673 meters were removed from the PCC schedule and will remain in the Meter Sampling Program. As of 12/31/2022, 4,424 meters from specific lots of Perf #572, 2005 Sensus R-275 remain listed for removal in the 2022 PCC program.
- 12 new meter families were added in 2022, reflecting new meters placed in service during the normal course of business, as well as meter replacements to replace non-conforming meters. 8 meter families were removed from service, due to small family size, during the normal course of business. 3 meter families were removed from service due to the number of supplementary samples required exceeding 50% of the family size, with a family size less than 100 meters.

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- 18 meter families, consisting of a total of 70,251 meters at the time of declaration, were identified as not conforming in 2022. Due to the number of meters requiring change-out (8.9% of the total population), these meters have been put on the list to be removed over the course of the next four years, by December 2026, per Meter Sampling Program (MSP) guidelines outlined in NW Natural Engineering Procedure Z-1. The performance of these families is exhibited in Appendix B.
- A further breakdown of the 18 non-conforming meter families and associated meters described above are as follows, the performance of these families is exhibited in Appendix B:
    - 7 meter families, totaling 70,167 meters had sufficient meter tests available to have their accuracy determined statistically and determined non-conforming. Significant results include:
        - 42,486 meters from the 2006 & 2007 American AC-250 meter families make up the bulk of this lot, reflecting the last American AC-250 meters in service from the 2005-2010 timeframe.
        - 13,495 American AL-175 meters from 1987, 1989, 1991
        - 14,106 American AC-250 meters from 1998
    - 8 meter families, totaling 25 meters, will be removed from service due to their small population size and age.
    - 3 meter families, totaling 59 meters, will be removed from service due to a family size less than 100 meters, and sampling requirements exceeding 50% of the total family population.
- Compared to the results above, the Year 2021 report resulted in 35,677 meters being put on the list for removal by December 2025.
- Regarding the planned four year removal of meters determined non-conforming from 2019-2022, the following meters remain:
    - PCC Year 2020 (for removal 2020 to 2023): 2,583 remain out of 42,046 determined
    - PCC Year 2021 (for removal 2021 to 2024): 9,487 remain out of 27,204 determined
    - PCC Year 2022 (for removal 2022 to 2025): 14,977 remain out of 35,677 determined
    - PCC Year 2023 (for removal 2023 to 2026): 69,184 remain out of 70,251 determined
- Consistent with the NW Natural's tariff, bills for meters that are subject to the four year removal schedule and are later found to not meet the accuracy requirement are deemed subject to refund to customers based on the date when the meter family was determined to require change-out to the date the meter was replaced.

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If you have any questions or comments, please contact me at 503-610-7494.

Sincerely,

/s/ *Michael J. McKenzie*

Michael J. McKenzie, PE
Engineering Manager
cc:

Dan Kizer
Jon Huddleston
Joe Karney
Dave Weber
Kim Rush

Docket No. UG 490

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RG 41 – NWN Meter Sampling Program Report
February 22, 2023, Page 4
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Appendix A
Meter Families in Conformance

Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
120	0	1968	Rockwell	175	54	53	41	2	0	43
120	0	1969	Rockwell	175	53	157	72	5	0	77
120	0	1970	Rockwell	175	52	529	96	9	1	106
120	0	1972	Rockwell	175	50	759	104	8	1	113
120	0	1973	Rockwell	175	49	562	95	10	1	106
120	0	1974	Rockwell	175	48	2383	236	15	7	258
120	0	1975	Rockwell	175	47	1647	145	18	2	165
120	0	1976	Rockwell	175	46	1003	103	6	4	113
120	0	1977	Rockwell	175	45	1228	114	7	1	122
120	0	1978	Rockwell	175	44	1328	121	8	4	133
120	0	1979	Rockwell	175	43	1491	152	10	4	166
120	0	1980	Rockwell	175	42	951	93	9	1	103
120	0	1981	Rockwell	175	41	617	101	7	2	110
120	0	1982	Rockwell	175	40	1094	111	14	1	126
120	0	1983	Rockwell	175	39	1246	122	16	2	140
120	0	1984	Rockwell	175	38	1359	117	14	1	132
120	0	1985	Rockwell	175	37	1818	134	18	1	153
120	0	1986	Rockwell	175	36	1200	109	8	3	120
120	0	1987	Rockwell	175	35	2084	147	6	3	156
120	0	1988	Rockwell	175	34	2035	155	7	5	167
120	0	1989	Rockwell	175	33	3295	218	12	6	236
120	0	1990	Rockwell	175	32	3317	210	15	6	231
120	0	1991	Rockwell	175	31	3598	262	7	13	282
120	0	1992	Rockwell	175	30	6335	398	11	14	423
120	0	1993	Rockwell	175	29	2502	166	8	4	178
120	0	1994	Rockwell	175	28	1285	96	3	4	103
120	0	1995	Rockwell	175	27	268	79	8	0	87
120	0	1996	Rockwell	175	26	703	89	3	0	92
120	0	1997	Rockwell	175	25	123	58	5	1	64
120	0	1998	Rockwell	175	24	45	29	1	1	31
120	0	2012	Rockwell	175	10	1	0	0	0	0

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
120	0	2013	Rockwell	175	9	1	0	0	0	0
120	0	2014	Rockwell	175	8	1	0	0	0	0
120	0	2015	Rockwell	275	7	1	0	0	0	0
120	0	2021	Rockwell	175	1	1	6	0	0	6
125	0	1978	Rockwell	200	44	1454	139	3	1	143
125	0	1979	Rockwell	200	43	142	38	1	0	39
125	0	1980	Rockwell	200	42	1723	126	15	1	142
125	0	1981	Rockwell	200	41	2346	145	10	0	155
125	0	1982	Rockwell	200	40	2923	188	7	0	195
125	0	1983	Rockwell	200	39	1646	141	4	2	147
125	0	1984	Rockwell	200	38	1986	130	14	1	145
125	0	1986	Rockwell	200	36	326	75	3	0	78
125	0	1987	Rockwell	200	35	490	68	3	0	71
125	0	1988	Rockwell	200	34	333	93	4	0	97
125	0	1989	Rockwell	200	33	429	87	5	3	95
125	0	1990	Rockwell	200	32	276	73	10	0	83
125	0	1991	Rockwell	200	31	657	48	0	0	48
125	0	1992	Rockwell	200	30	580	52	2	1	55
125	0	1993	Rockwell	200	29	453	81	6	2	89
125	0	1994	Rockwell	200	28	375	83	6	1	90
125	0	1995	Rockwell	200	27	66	46	5	0	51
125	0	1996	Rockwell	200	26	221	35	0	0	35
125	0	1998	Rockwell	200	24	39	39	3	0	42
125	0	1999	Rockwell	200	23	129	22	0	0	22
125	0	2017	Rockwell	200	5	1	3	0	0	3
125	0	2019	Rockwell	200	3	1	3	0	0	3
130	0	1971	American	175	51	976	92	11	0	103
130	0	1973	American	175	49	686	87	10	2	99
130	0	1975	American	175	47	21	15	0	0	15
130	0	1977	American	175	45	3006	207	24	4	235
130	0	1979	American	175	43	5997	374	20	4	398
130	0	1980	American	175	42	5790	376	24	5	405
130	0	1984	American	175	38	4466	283	40	8	331
130	0	1985	American	175	37	1953	124	13	1	138

Docket No. UG 490

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
130	0	1986	American	175	36	3749	201	31	6	238
130	0	1988	American	175	34	2940	184	27	3	214
130	0	1992	American	175	30	1303	93	16	0	109
130	0	1994	American	175	28	2503	119	20	0	139
130	0	1995	American	175	27	459	79	11	0	90
130	0	1996	American	175	26	1010	47	1	2	50
130	0	1997	American	175	25	195	51	1	1	53
130	0	2013	American	175	9	1	0	0	0	0
130	0	2014	American	175	8	3	0	0	0	0
130	0	2016	American	175	6	2	1	0	0	1
130	0	2020	American	175	2	1	13	1	0	14
130	0	2022	American	175	0	1	10	4	1	15
140	0	1968	Sprague	175	54	917	100	0	15	115
140	0	1970	Sprague	175	52	313	47	0	3	50
140	0	1971	Sprague	175	51	884	92	0	11	103
140	0	1972	Sprague	175	50	144	25	0	2	27
140	0	1973	Sprague	175	49	2670	247	3	8	258
140	0	1974	Sprague	175	48	574	51	0	2	53
140	0	1975	Sprague	175	47	664	60	0	3	63
140	0	1976	Sprague	175	46	1009	87	2	5	94
140	0	1977	Sprague	175	45	281	41	0	3	44
140	0	1978	Sprague	175	44	226	39	0	3	42
140	0	1979	Sprague	175	43	121	41	1	1	43
140	0	1980	Sprague	175	42	258	66	5	7	78
140	0	1981	Sprague	175	41	589	47	1	2	50
140	0	1982	Sprague	175	40	514	73	2	3	78
140	0	1983	Sprague	175	39	731	94	3	3	100
140	0	1984	Sprague	175	38	632	66	1	9	76
140	0	1985	Sprague	175	37	1052	105	1	7	113
140	0	1986	Sprague	175	36	908	60	1	3	64
140	0	1987	Sprague	175	35	2754	236	0	13	249
140	0	1988	Sprague	175	34	691	88	3	2	93
140	0	1989	Sprague	175	33	713	51	0	3	54
140	0	1990	Sprague	175	32	960	72	0	2	74

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
140	0	1991	Sprague	175	31	411	42	0	1	43
140	0	1992	Sprague	175	30	528	34	0	3	37
140	0	1993	Sprague	175	29	600	54	0	3	57
140	0	1994	Sprague	175	28	529	61	2	3	66
140	0	1997	Sprague	175	25	449	31	0	0	31
140	0	2016	Sprague	175	6	1	0	0	0	0
270	0	1998	Schlumberger	1000	24	17	11	0	0	11
270	0	2000	Schlumberger	1000	22	17	13	0	0	13
270	0	2001	Schlumberger	1000	21	20	37	2	0	39
450	0	1993	Schlumberger	400	29	166	32	0	0	32
450	0	1996	Schlumberger	400	26	238	38	0	0	38
450	0	1997	Schlumberger	400	25	43	20	0	0	20
450	0	1998	Schlumberger	400	24	397	57	0	1	58
450	0	1999	Schlumberger	400	23	80	21	0	0	21
450	0	2003	Schlumberger	400	19	15	13	0	0	13
450	0	2013	Schlumberger	400	9	1	0	0	0	0
452	0	2003	Actaris	400	19	72	28	0	0	28
452	0	2004	Actaris	400	18	372	86	2	3	91
470	472	1982	American	425	40	16	12	0	0	12
470	472	1983	American	425	39	18	14	0	0	14
470	472	1984	American	425	38	96	22	0	0	22
470	472	1985	American	425	37	21	22	2	0	24
470	472	1986	American	425	36	26	38	1	0	39
470	472	1987	American	425	35	97	60	3	0	63
470	472	1989	American	425	33	17	18	2	0	20
470	472	1992	American	425	30	105	43	2	0	45
470	472	1994	American	425	28	156	69	5	1	75
470	472	1995	American	425	27	73	22	0	0	22
470	472	1996	American	425	26	7	14	1	1	16
470	472	1997	American	425	25	263	78	5	0	83
470	472	1998	American	425	24	128	57	6	0	63
470	472	1999	American	425	23	219	42	2	0	44
470	472	2000	American	425	22	360	55	2	0	57
470	472	2001	American	425	21	49	37	3	0	40

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NW Natural®

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RG 41 – NWN Meter Sampling Program Report
February 22, 2023, Page 8
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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
470	472	2002	American	425	20	364	80	3	0	83
470	472	2003	American	425	19	137	69	3	0	72
470	472	2004	American	425	18	45	39	4	1	44
470	472	2006	American	425	16	34	35	0	0	35
470	472	2007	American	425	15	184	55	2	0	57
470	472	2008	American	425	14	10	13	0	0	13
470	472	2012	American	425	10	1	0	0	0	0
470	472	2017	American	425	5	1	0	0	0	0
471	0	2007	American	425	15	443	92	8	0	100
471	0	2008	American	425	14	36	35	3	0	38
471	0	2010	American	425	12	73	31	1	0	32
471	0	2011	American	425	11	76	33	1	0	34
471	0	2012	American	425	10	10	0	0	0	0
475	0	1996	American	630	26	1	0	0	0	0
475	0	2010	American	630	12	564	97	11	0	108
475	0	2011	American	630	11	993	82	1	0	83
475	0	2012	American	630	10	1378	100	0	0	100
475	0	2013	American	630	9	1438	94	2	0	96
475	0	2014	American	630	8	1501	83	0	1	84
475	0	2015	American	630	7	1211	73	1	0	74
475	0	2016	American	630	6	1586	67	0	0	67
475	0	2017	American	630	5	1653	70	2	0	72
475	0	2018	American	630	4	4574	165	2	2	169
475	0	2019	American	630	3	2923	111	0	0	111
475	0	2020	American	630	2	891	30	0	0	30
475	0	2021	American	630	1	1139	24	0	0	24
475	0	2022	American	630	0	1422	5	0	0	5
480	486	1989	American	800	33	21	12	0	0	12
480	486	1990	American	800	32	10	18	1	0	19
480	486	1992	American	800	30	18	13	0	0	13
480	486	1995	American	800	27	13	14	1	2	17
480	486	2001	American	800	21	11	10	1	0	11
480	486	2002	American	800	20	16	14	0	0	14
485	0	1981	American	800	41	16	15	0	3	18

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
485	0	1984	American	800	38	44	31	1	1	33
485	0	2016	American	800	6	1	0	0	0	0
487	0	2017	American	800	5	55	5	0	0	5
487	0	2018	American	800	4	187	13	0	0	13
487	0	2019	American	800	3	306	20	0	0	20
487	0	2020	American	800	2	231	12	0	0	12
487	0	2021	American	800	1	339	11	0	0	11
487	0	2022	American	800	0	284	4	0	0	4
500	502	2002	American	1000	20	27	25	2	1	28
505	507	2008	American	1000	14	259	92	11	0	103
505	507	2011	American	1000	11	293	91	7	0	98
505	507	2012	American	1000	10	354	54	2	0	56
505	507	2013	American	1000	9	353	47	0	0	47
505	507	2014	American	1000	8	408	48	0	0	48
505	507	2015	American	1000	7	339	31	0	0	31
505	507	2016	American	1000	6	489	56	0	0	56
505	507	2017	American	1000	5	190	20	0	0	20
505	507	2018	American	1000	4	330	30	2	0	32
505	507	2019	American	1000	3	285	32	1	0	33
505	507	2020	American	1000	2	15	2	1	0	3
505	507	2021	American	1000	1	11	2	1	0	3
505	507	2022	American	1000	0	5	0	0	0	0
510	515	1973	Rockwell	310	49	57	34	1	3	38
510	515	1974	Rockwell	310	48	20	23	0	4	27
510	515	1976	Rockwell	310	46	214	62	3	5	70
510	515	1977	Rockwell	310	45	122	41	1	0	42
510	515	1978	Rockwell	310	44	79	54	1	3	58
510	515	1979	Rockwell	310	43	109	53	5	8	66
510	515	1981	Rockwell	310	41	161	30	0	3	33
510	515	1982	Rockwell	310	40	34	42	1	4	47
510	515	1983	Rockwell	310	39	91	42	1	0	43
510	515	1984	Rockwell	310	38	11	17	1	1	19
510	515	1986	Rockwell	310	36	14	11	0	0	11
510	515	1987	Rockwell	310	35	184	51	1	1	53

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
510	515	1989	Rockwell	310	33	65	34	1	0	35
510	515	1990	Rockwell	310	32	178	68	6	2	76
510	515	1991	Rockwell	310	31	192	26	0	1	27
510	515	1992	Rockwell	310	30	90	50	5	4	59
510	515	1993	Rockwell	310	29	87	19	0	2	21
510	515	1994	Rockwell	310	28	26	16	0	0	16
510	515	1996	Rockwell	310	26	18	20	0	1	21
520	0	1977	Rockwell	415	45	32	16	0	0	16
520	0	1978	Rockwell	415	44	26	17	0	0	17
520	0	1979	Rockwell	415	43	59	33	0	3	36
520	0	1980	Rockwell	415	42	47	37	2	0	39
520	0	1981	Rockwell	415	41	196	30	0	2	32
520	0	1982	Rockwell	415	40	31	16	0	0	16
520	0	1988	Rockwell	415	34	38	16	0	1	17
520	0	1991	Rockwell	415	31	60	17	0	1	18
520	0	1992	Rockwell	415	30	42	29	1	3	33
520	0	1994	Rockwell	415	28	78	21	0	1	22
520	0	1996	Rockwell	415	26	87	49	2	1	52
520	0	1997	Rockwell	415	25	40	17	0	1	18
520	0	2003	Rockwell	415	19	128	31	0	0	31
520	0	2004	Rockwell	415	18	54	43	4	0	47
520	0	2005	Rockwell	415	17	19	27	1	0	28
520	0	2017	Rockwell	415	5	1	0	0	0	0
520	0	2018	Rockwell	415	4	1	0	0	0	0
520	0	2019	Rockwell	415	3	1	0	0	0	0
520	0	2020	Rockwell	415	2	1	1	0	0	1
555	0	1980	American	310	42	47	43	3	0	46
555	0	1981	American	310	41	24	18	0	1	19
555	0	1983	American	310	39	66	51	3	0	54
555	0	1984	American	310	38	148	62	3	1	66
555	0	1985	American	310	37	71	41	2	0	43
555	0	1987	American	310	35	27	33	2	1	36
555	0	1989	American	310	33	7	7	0	0	7
560	0	1985	American	250	37	1358	83	3	1	87

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
560	0	1986	American	250	36	5844	323	7	3	333
560	0	1987	American	250	35	405	31	0	0	31
560	0	1988	American	250	34	3007	136	3	0	139
560	0	1989	American	250	33	6619	374	5	5	384
560	0	1990	American	250	32	5985	288	9	5	302
560	0	1991	American	250	31	5270	279	5	4	288
560	0	1992	American	250	30	4630	155	3	5	163
560	0	1993	American	250	29	3908	156	0	2	158
560	0	1994	American	250	28	5913	186	13	1	200
560	0	1995	American	250	27	7864	270	20	3	293
560	0	1996	American	250	26	10698	375	21	4	400
560	0	1999	American	250	23	10906	273	27	1	301
560	0	2000	American	250	22	10917	319	7	2	328
560	0	2001	American	250	21	9195	217	6	1	224
560	0	2002	American	250	20	8289	187	11	0	198
560	0	2003	American	250	19	394	76	0	2	78
560	0	2005	American	250	17	43	30	1	0	31
560	0	2006	American	250	16	579	67	2	0	69
560	0	2007	American	250	15	179	23	0	0	23
560	0	2012	American	250	10	6	0	0	0	0
560	0	2013	American	250	9	2	0	0	0	0
560	0	2014	American	250	8	5	0	0	0	0
560	0	2015	American	250	7	1	0	0	0	0
560	0	2018	American	250	4	3	14	1	0	15
560	0	2022	American	250	0	1	10	0	0	10
561	0	1984	American	250	38	1	0	0	0	0
561	0	2010	American	250	12	9772	348	8	2	358
561	0	2011	American	250	11	10269	398	5	0	403
561	0	2012	American	250	10	11517	428	3	3	434
561	0	2013	American	250	9	14974	408	4	5	417
561	0	2014	American	250	8	14316	374	4	1	379
561	0	2015	American	250	7	17580	385	1	1	387
561	0	2016	American	250	6	12458	225	0	0	225
561	0	2017	American	250	5	11632	243	2	1	246

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
561	0	2018	American	250	4	9609	172	2	3	177
561	0	2019	American	250	3	14433	197	2	0	199
561	0	2020	American	250	2	10627	109	10	0	119
561	0	2021	American	250	1	6920	70	13	0	83
561	0	2022	American	250	0	6316	32	10	0	42
562	0	2017	American	250	5	22	0	0	0	0
562	0	2018	American	250	4	695	0	0	0	0
562	0	2019	American	250	3	1369	5	1	0	6
562	0	2020	American	250	2	996	0	0	0	0
562	0	2021	American	250	1	1101	2	0	0	2
562	0	2022	American	250	0	567	0	0	0	0
570	0	1989	Rockwell	275	33	682	80	3	0	83
570	0	1990	Rockwell	275	32	5186	200	7	2	209
570	0	1991	Rockwell	275	31	2772	132	7	0	139
570	0	1992	Rockwell	275	30	124	57	5	0	62
570	0	1993	Rockwell	275	29	58	33	1	0	34
570	0	1994	Rockwell	275	28	4881	167	6	0	173
570	0	1995	Rockwell	275	27	6226	240	9	5	254
570	0	1996	Rockwell	275	26	7471	203	3	3	209
570	0	1997	Rockwell	275	25	2298	59	1	0	60
570	0	1998	Rockwell	275	24	5258	166	18	1	185
570	0	1999	Rockwell	275	23	10214	262	35	4	301
570	0	2000	Rockwell	275	22	8251	193	24	3	220
570	0	2001	Rockwell	275	21	8448	218	8	0	226
570	0	2002	Rockwell	275	20	10575	234	2	0	236
570	0	2003	Rockwell	275	19	19336	505	8	1	514
570	0	2004	Rockwell	275	18	3508	91	0	0	91
570	0	2005	Rockwell	275	17	6	7	0	0	7
570	0	2012	Rockwell	275	10	4	1	0	0	1
570	0	2013	Rockwell	275	9	1	0	0	0	0
570	0	2014	Rockwell	275	8	2	0	0	0	0
570	0	2016	Rockwell	275	6	2	0	0	0	0
570	0	2017	Rockwell	275	5	3	3	0	0	3
570	0	2018	Rockwell	275	4	2	2	0	0	2

Docket No. UG 490

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
570	0	2022	Rockwell	275	0	1	6	1	0	7
572	0	1999	Sensus	275	23	1	0	0	0	0
572	0	2004	Sensus	275	18	13585	325	22	2	349
572	0	2005	Sensus	275	17	6673	5493	335	7	5835
572	0	2008	Sensus	275	14	34	40	1	0	41
572	0	2009	Sensus	275	13	721	55	1	0	56
572	0	2011	Sensus	275	11	63	20	0	0	20
572	0	2012	Sensus	275	10	3	1	0	0	1
572	0	2013	Sensus	275	9	1	0	0	0	0
572	0	2014	Sensus	275	8	2	0	0	0	0
572	0	2015	Sensus	275	7	2	0	0	0	0
572	0	2016	Sensus	275	6	3	0	0	0	0
572	0	2020	Sensus	275	2	9354	109	3	1	113
572	0	2021	Sensus	275	1	11989	108	0	2	110
572	0	2022	Sensus	275	0	12986	70	2	0	72
585	0	1988	Sprague	250	34	169	22	0	0	22
585	0	1991	Sprague	250	31	681	65	1	0	66
585	0	1992	Sprague	250	30	1989	126	1	1	128
585	0	1993	Sprague	250	29	3673	188	1	0	189
585	0	1994	Sprague	250	28	1598	73	0	1	74
585	0	1995	Sprague	250	27	1442	75	2	1	78
585	0	1996	Sprague	250	26	4262	189	1	1	191
585	0	1997	Sprague	250	25	5721	222	2	2	226
585	0	1998	Sprague	250	24	5200	231	1	1	233
585	0	1999	Sprague	250	23	196	54	1	0	55
585	0	2000	Sprague	250	22	31	29	2	0	31
585	0	2001	Sprague	250	21	47	19	0	0	19
585	0	2002	Sprague	250	20	43	16	0	0	16
585	0	2004	Sprague	250	18	42	20	0	1	21
585	0	2014	Sprague	250	8	2	0	0	0	0
585	0	2021	Sprague	175	1	1	2	0	0	2
590	0	1988	Lancaster	250	34	68	19	0	0	19
590	0	1989	Lancaster	250	33	1237	93	0	0	93
590	0	1990	Lancaster	250	32	1254	79	0	1	80

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
590	0	1991	Lancaster	250	31	1628	107	1	0	108
590	0	1992	Lancaster	250	30	2536	151	2	0	153
590	0	1993	Lancaster	250	29	2740	104	2	0	106
590	0	1994	Lancaster	250	28	4163	232	12	3	247
590	0	1995	Lancaster	250	27	4594	227	13	15	255
590	0	1996	Lancaster	250	26	25	22	0	0	22
590	0	1997	Lancaster	250	25	2042	83	1	2	86
590	0	1998	Lancaster	250	24	15	14	0	0	14
590	0	1999	Lancaster	250	23	96	54	2	0	56
590	0	2016	Lancaster	250	6	1	0	0	0	0
590	0	2019	Lancaster	250	3	1	1	0	0	1
590	0	2021	Lancaster	250	1	1	2	0	0	2
590	0	2022	Lancaster	250	0	1	0	0	0	0
595	600	2000	Schlumberger	250	22	2806	482	22	18	522
595	600	2001	Schlumberger	250	21	3532	324	7	1	332
595	600	2002	Schlumberger	250	20	3098	199	1	8	208
595	600	2003	Schlumberger	250	19	44	18	0	0	18
595	600	2004	Schlumberger	250	18	20	12	0	0	12
595	600	2012	Schlumberger	250	10	1	0	0	0	0
595	600	2016	Schlumberger	250	6	1	1	0	0	1
595	600	2019	Schlumberger	250	3	1	3	0	0	3
602	0	1997	Itron	250	25	1	0	0	0	0
602	0	2016	Itron	250	6	4270	110	0	1	111
602	0	2017	Itron	250	5	4521	98	0	1	99
602	0	2018	Itron	250	4	8079	133	2	0	135
602	0	2019	Itron	250	3	11408	155	0	0	155
602	0	2020	Itron	250	2	21275	211	0	0	211
602	0	2021	Itron	250	1	22427	115	1	0	116
602	0	2022	Itron	250	0	8829	34	0	0	34
603	0	2020	Itron	400	2	421	18	0	0	18
603	0	2021	Itron	400	1	380	7	0	0	7
603	0	2022	Itron	400	0	32	0	0	0	0
					Total	**695,137**				

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Appendix B
Meter Families Not Conforming (To Be Removed Over 4 Years)

Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	% Not Conforming	PCC Reason
130	0	1987	American	175	35	5684	217	36	1	14.6%	Determined
130	0	1989	American	175	33	3116	135	23	4	16.7%	Determined
130	0	1991	American	175	31	4695	183	29	5	15.7%	Determined
130	0	2021	American	175	1	1	5	1	0	16.7%	Small Family
272	0	2004	Actaris	1000	18	7	7	1	0	12.5%	Small Family
300	540	2005	Rockwell	800	17	4	6	0	1	14.3%	Small Family
505	507	1981	American	1000	41	6	8	0	2	20.0%	Small Family
520	0	2000	Rockwell	415	22	80	41	7	0	14.6%	Determined
560	0	1998	American	250	24	14106	301	47	3	14.2%	Determined
560	0	2021	American	250	1	1	16	6	0	27.3%	Small Family
561	0	2006	American	250	16	21038	448	70	0	13.5%	Determined
561	0	2007	American	250	15	21448	534	82	2	13.6%	Determined
570	0	2021	Rockwell	275	1	4	1	1	0	50.0%	Small Family
602	0	1981	Itron	250	41	1	0	0	0	0%	Small Family
602	0	1993	Itron	250	29	1	0	0	0	0%	Small Family
470	472	2005	American	425	17	17	6	1	0	14.3%	Samples >50%
520	0	1987	Rockwell	415	35	35	6	0	1	14.3%	Samples >50%
140	0	1998	Sprague	175	24	7	1	0	0	0.0%	Samples >50%
					Total	**70,251**					

Staff/906
Dlouhy/57

Oregon Public Utility Commission

Docket No. UG 490

e-FILING REPORT COVER SHEET

COMPANY NAME: NW Natural

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☐ No ☐ Yes If yes, submit a redacted public version (or a cover letter) by email. Submit the confidential information as directed in OAR 860-001-0070 or the terms of an applicable protective order.

Select report type: ☐ RE (Electric) ☐ RG (Gas) ☐ RW (Water) ☐ RT (Telecommunications)
☐ RO (Other, for example, industry safety information)

Did you previously file a similar report? ☐ No ☐ Yes, report docket number: RG 41

Report is required by: ☐ OAR
☐ Statute
☐ Order
Note: A one-time submission required by an order is a compliance filing and not a report (file compliance in the applicable docket)
☑ Other At request of Commission Staff
(For example, federal regulations, or requested by Staff)

Is this report associated with a specific docket/case? ☐ No ☐ Yes, docket number: RG 41

List Key Words for this report. We use these to improve search results.

Meter Sampling for 2020, NW Natural

Send the completed Cover Sheet and the Report in an email addressed to PUC.FilingCenter@puc.oregon.gov

Send confidential information, voluminous reports, or energy utility Results of Operations Reports to PUC Filing Center, PO Box 1088, Salem, OR 97308-1088 or by delivery service to 201 High Street SE Suite 100, Salem, OR 97301.

Print

Docket No. UG 490

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February 22, 2024

VIA ELECTRONIC FILING

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Salem, Oregon 97308-1088

Re: RG 41: Meter Sampling Program Report for 2023

At the request of Commission Staff, Northwest Natural Gas Company, dba NW Natural, submits herewith its 2023 Meter Sampling Program Report.

As required by our Meter Testing Standards and Procedures document, the accuracies of all operating families of diaphragm meters with capacities 1000 ft^3/hr and below have been statistically analyzed for the year 2023. This analysis utilized all relevant meter tests conducted during the five calendar years between January 1, 2018, and December 31, 2023. The results of this analysis are as follows:

- As of December 31, 2023, 803,119 meters are installed and covered under the Meter Sampling Program. Of these, 716,844 meters, forming 362 distinct meter families, are conforming. The remaining 86,275 meters form 83 distinct meter families and are non-conforming and are scheduled for replacement. 59 non-conforming meter families were identified in prior years and 24 new meter families were identified as non-conforming in 2023. The 86,275 non-conforming meters represent 10.7 percent of the total meter population.
- Over the course of 2023, the company tested 7,996 meters. Over the five-year period of 2018 through 2023, the company had a total of 41,217 meter samples from which to base its results.
- 362 meter families either had sufficient meter samples to establish statistical confidence in their accuracy, or are new for 2023. These meter families amount to 716,844 meters, or 89.3 percent of the total meter population. The performances of these families are exhibited in Appendix A.
- 14 new meter families were added in 2023, reflecting new meters placed in service during the normal course of business, as well as meter replacements to replace non-conforming meters. 17 meter families were removed from service due to small family size, during the normal course of business. 4 meter families were removed from service due to the number of supplementary samples required exceeding 50 percent of the family size, with a family size less than 100 meters.
- 25 meter families, consisting of a total of 2,612 meters at the time of declaration, were identified as not conforming in 2023. Per Meter Sampling Program (MSP) guidelines outlined in NW Natural Engineering Procedure Z-1, these will be removed by the end of 2024. The performance of these families is exhibited in Appendix B.
    - The 2023 Meter Sampling Annual Report shows a significant decrease in meters declared non-conforming when compared to the 2022 annual report. In 2022, NW Natural declared 70,251 meters as non-conforming, which consisted predominantly of 42,486 American AC-250 meters

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set in 2006 and 2007, and an additional 14,106 American AC-250 meters set in 1998. These meter families are large, and were predominantly made up of the American meter families that NW Natural has seen fail earlier than expected, which were set from 2005-2009. Those meters from 2005-2009 have now all been declared PCC. For 2023, NW Natural has seen what we would consider a more typical year with only one larger meter family, the 1994 American AL-175 being declared PCC, and we would expect this trend to continue as meters age into the 30-40 year range.

- A further breakdown of the 25 non-conforming meter families and associated meters described above are as follows, the performance of these families is exhibited in Appendix B:
  - 4 meter families, totaling 2,525 meters had sufficient meter tests available to have their accuracy determined statistically and determined non-conforming.
  - 17 meter families, totaling 33 meters, will be removed from service due to their small population size and age.
  - 4 meter families, totaling 54 meters, will be removed from service due to a family size less than 100 meters, and sampling requirements exceeding 50 percent of the total family population.
- Compared to the results above, the Year 2022 report resulted in 70,251 meters being put on the list for removal over five years by December 2026.
- Regarding the planned four-year removal of meters determined non-conforming from 2020-2023, the following meters remain:
  - PCC Year 2020 (for removal 2020 to 2023): 1 remains out of 42,252 determined
    - 1 meter remains for PCC Year 2020 due to access issues.
  - PCC Year 2021 (for removal 2021 to 2024): 6,515 remain out of 27,898 determined.
  - PCC Year 2022 (for removal 2022 to 2025): 9,783 remain out of 35,677 determined.
  - PCC Year 2023 (for removal 2023 to 2026): 67,484 remain out of 70,251 determined.
  - PCC Year 2024 (for removal in 2024): 2,492 remain out of 2,612 determined.

If you have any questions or comments, please contact me at matt.miller@nwnatural.com.

Sincerely,
/s/ *Matt Miller*

Matt Miller
Engineering

Michael J. McKenzie, P.E.
Engineering Manager
cc:

Dan Kizer – Engineering Sr Director
Cari Colton – Utility Technical Services Sr Director
Joe Karney – VP, Engineering & Utility Operations
Dave Weber – VP, Gas Supply & Utility Support Services
Kim Rush – SVP, Chief Operating Officer

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Appendix A
Meter Families in Conformance (Excluding new meters)

Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
120	0	1969	Rockwell	175	54	157	67	4	0	71
120	0	1970	Rockwell	175	53	533	93	9	1	103
120	0	1972	Rockwell	175	51	762	84	6	1	91
120	0	1973	Rockwell	175	50	564	87	10	1	98
120	0	1974	Rockwell	175	49	2386	188	12	6	206
120	0	1975	Rockwell	175	48	1649	126	12	2	140
120	0	1976	Rockwell	175	47	1010	94	3	4	101
120	0	1977	Rockwell	175	46	1238	104	6	1	111
120	0	1978	Rockwell	175	45	1334	107	5	4	116
120	0	1979	Rockwell	175	44	1495	141	8	4	153
120	0	1981	Rockwell	175	42	619	95	4	2	101
120	0	1983	Rockwell	175	40	1249	115	14	2	131
120	0	1985	Rockwell	175	38	1819	118	13	1	132
120	0	1986	Rockwell	175	37	1201	98	6	2	106
120	0	1987	Rockwell	175	36	2087	129	3	3	135
120	0	1988	Rockwell	175	35	2039	135	5	5	145
120	0	1989	Rockwell	175	34	3301	184	9	5	198
120	0	1990	Rockwell	175	33	3326	194	12	6	212
120	0	1991	Rockwell	175	32	3603	221	6	13	240
120	0	1992	Rockwell	175	31	6347	343	4	13	360
120	0	1993	Rockwell	175	30	2507	151	5	4	160
120	0	1994	Rockwell	175	29	1286	83	3	4	90
120	0	1995	Rockwell	175	28	269	77	8	0	85
120	0	1996	Rockwell	175	27	703	80	2	0	82
120	0	1998	Rockwell	175	25	45	29	1	1	31
120	0	2014	Rockwell	175	9	1	0	0	0	0
120	0	2015	Rockwell	175	8	1	0	0	0	0
120	0	2021	Rockwell	175	2	1	6	0	0	6
125	0	1978	Rockwell	200	45	1459	117	2	1	120
125	0	1980	Rockwell	200	43	1727	93	8	1	102
125	0	1981	Rockwell	200	42	2358	108	6	0	114
125	0	1982	Rockwell	200	41	2928	170	5	0	175
125	0	1983	Rockwell	200	40	1649	135	2	2	139
125	0	1984	Rockwell	200	39	1989	120	10	0	130
125	0	1986	Rockwell	200	37	326	74	2	0	76
125	0	1988	Rockwell	200	35	333	89	3	0	92
125	0	1989	Rockwell	200	34	429	83	5	3	91
125	0	1991	Rockwell	200	32	657	41	0	0	41
125	0	1992	Rockwell	200	31	580	49	1	1	51
125	0	1993	Rockwell	200	30	457	26	0	2	28
125	0	1996	Rockwell	200	27	221	35	0	0	35
125	0	1998	Rockwell	200	25	39	38	3	0	41

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
125	0	2017	Rockwell	200	6	1	0	0	0	0
125	0	2019	Rockwell	200	4	1	3	0	0	3
130	0	1971	American	175	52	979	80	11	0	91
130	0	1973	American	175	50	688	83	10	2	95
130	0	1975	American	175	48	21	15	0	0	15
130	0	1977	American	175	46	3021	177	25	4	206
130	0	1979	American	175	44	6012	333	19	2	354
130	0	1980	American	175	43	5799	343	23	5	371
130	0	1984	American	175	39	4477	246	35	8	289
130	0	1985	American	175	38	1954	110	11	0	121
130	0	1986	American	175	37	3756	176	24	6	206
130	0	1988	American	175	35	2945	134	20	3	157
130	0	1992	American	175	31	1307	89	15	0	104
130	0	1995	American	175	28	461	76	11	0	87
130	0	1997	American	175	26	195	51	1	1	53
130	0	2014	American	175	9	3	0	0	0	0
130	0	2016	American	175	7	2	0	0	0	0
130	0	2020	American	175	3	1	13	1	0	14
140	0	1968	Sprague	175	55	918	87	0	11	98
140	0	1970	Sprague	175	53	314	37	0	2	39
140	0	1971	Sprague	175	52	891	86	0	9	95
140	0	1973	Sprague	175	50	2674	217	3	6	226
140	0	1974	Sprague	175	49	575	44	0	2	46
140	0	1975	Sprague	175	48	667	55	0	3	58
140	0	1976	Sprague	175	47	1013	77	1	5	83
140	0	1977	Sprague	175	46	281	37	0	3	40
140	0	1978	Sprague	175	45	226	39	0	3	42
140	0	1980	Sprague	175	43	259	63	5	7	75
140	0	1981	Sprague	175	42	591	43	1	2	46
140	0	1982	Sprague	175	41	519	68	1	3	72
140	0	1983	Sprague	175	40	733	86	3	1	90
140	0	1985	Sprague	175	38	1056	91	0	6	97
140	0	1986	Sprague	175	37	908	54	0	3	57
140	0	1987	Sprague	175	36	2756	214	0	8	222
140	0	1988	Sprague	175	35	692	81	3	1	85
140	0	1989	Sprague	175	34	715	45	0	2	47
140	0	1990	Sprague	175	33	962	63	0	2	65
140	0	1991	Sprague	175	32	411	37	0	0	37
140	0	1992	Sprague	175	31	531	31	0	2	33
140	0	1993	Sprague	175	30	600	49	0	3	52
140	0	1994	Sprague	175	29	530	54	2	1	57
140	0	1997	Sprague	175	26	449	28	0	0	28
140	0	2016	Sprague	175	7	1	0	0	0	0
270	0	2001	Schlumberger	1000	22	20	35	2	0	37
450	0	1993	Schlumberger	400	30	167	24	0	0	24
450	0	1996	Schlumberger	400	27	240	33	0	0	33

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450	0	1997	Schlumberger	400	26	43	19	0	0	19
450	0	1998	Schlumberger	400	25	398	52	0	1	53
450	0	1999	Schlumberger	400	24	80	20	0	0	20
450	0	2003	Schlumberger	400	20	15	13	0	0	13
450	0	2022	Schlumberger	400	1	1	0	0	0	0
452	0	2003	Actaris	400	20	72	28	0	0	28
452	0	2004	Actaris	400	19	374	66	2	1	69
470	472	1983	American	425	40	18	11	0	0	11
470	472	1986	American	425	37	27	38	1	0	39
470	472	1987	American	425	36	97	53	3	0	56
470	472	1994	American	425	29	156	65	5	1	71
470	472	1995	American	425	28	73	19	0	0	19
470	472	1996	American	425	27	7	12	0	1	13
470	472	2000	American	425	23	363	49	1	0	50
470	472	2002	American	425	21	364	74	3	0	77
470	472	2003	American	425	20	137	67	3	0	70
470	472	2004	American	425	19	45	39	4	1	44
470	472	2007	American	425	16	184	52	2	0	54
470	472	2008	American	425	15	10	13	0	0	13
470	472	2017	American	425	6	1	0	0	0	0
471	0	2007	American	425	16	444	84	4	0	88
471	0	2008	American	425	15	36	35	2	0	37
471	0	2011	American	425	12	76	31	1	0	32
475	0	2010	American	630	13	564	91	11	0	102
475	0	2011	American	630	12	993	73	1	0	74
475	0	2012	American	630	11	1380	81	0	0	81
475	0	2013	American	630	10	1441	79	2	0	81
475	0	2014	American	630	9	1504	74	0	1	75
475	0	2015	American	630	8	1215	67	1	0	68
475	0	2016	American	630	7	1588	59	0	0	59
475	0	2017	American	630	6	1654	63	1	0	64
475	0	2018	American	630	5	4575	165	2	2	169
475	0	2019	American	630	4	2922	111	0	0	111
475	0	2020	American	630	3	891	30	0	0	30
475	0	2021	American	630	2	1139	24	0	0	24
475	0	2022	American	630	1	1410	5	0	0	5
480	486	1990	American	800	33	10	17	1	0	18
480	486	1995	American	800	28	13	13	1	2	16
480	486	2001	American	800	22	11	8	0	0	8
480	486	2002	American	800	21	16	13	0	0	13
485	0	1981	American	800	42	16	14	0	3	17
485	0	1984	American	800	39	45	25	1	1	27
485	0	2016	American	800	7	1	0	0	0	0
487	0	2017	American	800	6	55	5	0	0	5
487	0	2018	American	800	5	187	12	0	0	12
487	0	2019	American	800	4	307	20	0	0	20

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487	0	2020	American	800	3	231	12	0	0	12
487	0	2021	American	800	2	340	11	0	0	11
487	0	2022	American	800	1	287	4	0	0	4
500	502	2002	American	1000	21	27	25	2	1	28
505	507	2008	American	1000	15	260	84	10	0	94
505	507	2011	American	1000	12	294	82	7	0	89
505	507	2013	American	1000	10	353	35	0	0	35
505	507	2014	American	1000	9	408	42	0	0	42
505	507	2015	American	1000	8	339	26	0	0	26
505	507	2016	American	1000	7	490	48	0	0	48
505	507	2017	American	1000	6	190	17	0	0	17
505	507	2018	American	1000	5	331	30	2	0	32
505	507	2019	American	1000	4	285	32	1	0	33
505	507	2020	American	1000	3	15	2	1	0	3
505	507	2021	American	1000	2	11	2	1	0	3
505	507	2022	American	1000	1	5	0	0	0	0
510	515	1973	Rockwell	310	50	57	33	1	3	37
510	515	1974	Rockwell	310	49	20	23	0	4	27
510	515	1977	Rockwell	310	46	122	35	1	0	36
510	515	1978	Rockwell	310	45	80	49	1	2	52
510	515	1979	Rockwell	310	44	110	50	5	8	63
510	515	1982	Rockwell	310	41	34	41	1	4	46
510	515	1983	Rockwell	310	40	93	38	0	0	38
510	515	1987	Rockwell	310	36	186	40	1	1	42
510	515	1989	Rockwell	310	34	65	22	0	0	22
510	515	1990	Rockwell	310	33	179	63	6	2	71
510	515	1991	Rockwell	310	32	192	24	0	0	24
510	515	1994	Rockwell	310	29	26	16	0	0	16
510	515	1996	Rockwell	310	27	18	19	0	1	20
520	0	1977	Rockwell	415	46	32	15	0	0	15
520	0	1981	Rockwell	415	42	196	26	0	2	28
520	0	1991	Rockwell	415	32	60	17	0	1	18
520	0	1992	Rockwell	415	31	42	25	1	2	28
520	0	1994	Rockwell	415	29	78	18	0	1	19
520	0	1996	Rockwell	415	27	88	43	2	1	46
520	0	1997	Rockwell	415	26	40	16	0	1	17
520	0	2003	Rockwell	415	20	129	28	0	0	28
520	0	2004	Rockwell	415	19	54	43	4	0	47
520	0	2005	Rockwell	415	18	19	26	1	0	27
520	0	2017	Rockwell	415	6	1	0	0	0	0
520	0	2018	Rockwell	415	5	1	0	0	0	0
520	0	2019	Rockwell	415	4	1	0	0	0	0
520	0	2020	Rockwell	415	3	1	1	0	0	1
555	0	1983	American	310	40	66	48	3	0	51
555	0	1984	American	310	39	148	62	3	1	66
555	0	1985	American	310	38	71	39	2	0	41

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555	0	1989	American	310	34	7	7	0	0	7
560	0	1985	American	250	38	1361	76	3	1	80
560	0	1986	American	250	37	5853	273	7	3	283
560	0	1987	American	250	36	405	25	0	0	25
560	0	1988	American	250	35	3010	117	2	0	119
560	0	1989	American	250	34	6632	328	5	5	338
560	0	1990	American	250	33	5992	254	9	4	267
560	0	1991	American	250	32	5273	243	5	4	252
560	0	1992	American	250	31	4632	142	3	5	150
560	0	1993	American	250	30	3911	136	0	2	138
560	0	1994	American	250	29	5919	170	10	1	181
560	0	1995	American	250	28	7876	241	17	3	261
560	0	1996	American	250	27	10708	335	21	3	359
560	0	1999	American	250	24	10917	246	25	1	272
560	0	2000	American	250	23	10924	287	5	2	294
560	0	2001	American	250	22	9200	187	6	1	194
560	0	2002	American	250	21	8299	171	8	0	179
560	0	2003	American	250	20	395	48	0	2	50
560	0	2005	American	250	18	44	30	1	0	31
560	0	2006	American	250	17	580	61	2	0	63
560	0	2007	American	250	16	179	23	0	0	23
560	0	2014	American	250	9	5	0	0	0	0
560	0	2015	American	250	8	1	0	0	0	0
560	0	2018	American	250	5	3	14	1	0	15
560	0	2022	American	250	1	1	10	0	0	10
561	0	2010	American	250	13	9777	309	7	2	318
561	0	2011	American	250	12	10282	364	5	0	369
561	0	2012	American	250	11	11527	397	2	3	402
561	0	2013	American	250	10	14981	353	3	4	360
561	0	2014	American	250	9	14324	346	4	1	351
561	0	2015	American	250	8	17597	347	1	1	349
561	0	2016	American	250	7	12472	182	0	0	182
561	0	2017	American	250	6	11644	194	0	1	195
561	0	2018	American	250	5	9615	172	2	3	177
561	0	2019	American	250	4	14438	197	2	0	199
561	0	2020	American	250	3	10632	109	10	0	119
561	0	2023	American	250	0	4	0	0	0	0
562	0	2017	American	250	6	22	0	0	0	0
562	0	2018	American	250	5	695	0	0	0	0
562	0	2019	American	250	4	1369	5	1	0	6
562	0	2020	American	250	3	996	0	0	0	0
562	0	2021	American	250	2	1101	2	0	0	2
562	0	2022	American	250	1	564	0	0	0	0
570	0	1989	Rockwell	275	34	683	75	3	0	78
570	0	1990	Rockwell	275	33	5189	182	5	0	187
570	0	1991	Rockwell	275	32	2774	120	4	0	124

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
570	0	1994	Rockwell	275	29	4886	154	6	0	160
570	0	1995	Rockwell	275	28	6232	219	7	5	231
570	0	1996	Rockwell	275	27	7475	178	2	3	183
570	0	1997	Rockwell	275	26	2301	46	1	0	47
570	0	1998	Rockwell	275	25	5260	152	18	1	171
570	0	1999	Rockwell	275	24	10222	239	20	4	263
570	0	2000	Rockwell	275	23	8262	174	17	3	194
570	0	2001	Rockwell	275	22	8479	197	7	0	204
570	0	2002	Rockwell	275	21	10583	197	1	0	198
570	0	2003	Rockwell	275	20	19351	452	7	1	460
570	0	2004	Rockwell	275	19	3508	80	0	0	80
570	0	2014	Rockwell	275	9	2	0	0	0	0
570	0	2016	Rockwell	275	7	2	0	0	0	0
570	0	2017	Rockwell	275	6	3	0	0	0	0
570	0	2018	Rockwell	275	5	2	2	0	0	2
572	0	2004	Sensus	275	19	13595	293	20	1	314
572	0	2005	Sensus	275	18	11109	5433	328	7	5768
572	0	2008	Sensus	275	15	34	40	1	0	41
572	0	2009	Sensus	275	14	722	51	1	0	52
572	0	2011	Sensus	275	12	63	18	0	0	18
572	0	2014	Sensus	275	9	2	0	0	0	0
572	0	2015	Sensus	275	8	2	0	0	0	0
572	0	2016	Sensus	275	7	3	0	0	0	0
572	0	2020	Sensus	275	3	9369	109	3	1	113
572	0	2021	Sensus	275	2	11997	108	0	2	110
572	0	2022	Sensus	275	1	12972	70	1	0	71
572	0	2023	Sensus	275	0	2	0	0	0	0
585	0	1991	Sprague	250	32	684	64	1	0	65
585	0	1992	Sprague	250	31	1990	114	1	1	116
585	0	1993	Sprague	250	30	3681	175	1	0	176
585	0	1994	Sprague	250	29	1599	66	0	1	67
585	0	1995	Sprague	250	28	1444	70	2	1	73
585	0	1996	Sprague	250	27	4266	167	1	1	169
585	0	1997	Sprague	250	26	5728	196	1	1	198
585	0	1998	Sprague	250	25	5205	211	1	1	213
585	0	1999	Sprague	250	24	196	52	1	0	53
585	0	2001	Sprague	250	22	47	19	0	0	19
585	0	2002	Sprague	250	21	43	16	0	0	16
585	0	2004	Sprague	250	19	42	20	0	1	21
585	0	2014	Sprague	250	9	2	0	0	0	0
585	0	2021	Sprague	250	2	1	2	0	0	2
590	0	1989	Lancaster	250	34	1242	77	0	0	77
590	0	1990	Lancaster	250	33	1255	70	0	1	71
590	0	1991	Lancaster	250	32	1632	93	1	0	94
590	0	1992	Lancaster	250	31	2541	133	1	0	134
590	0	1993	Lancaster	250	30	2743	93	2	0	95

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
590	0	1994	Lancaster	250	29	4166	195	10	3	208
590	0	1995	Lancaster	250	28	4598	200	11	13	224
590	0	1996	Lancaster	250	27	25	22	0	0	22
590	0	1997	Lancaster	250	26	2042	73	1	1	75
590	0	1998	Lancaster	250	25	15	13	0	0	13
590	0	1999	Lancaster	250	24	96	52	2	0	54
590	0	2016	Lancaster	250	7	1	0	0	0	0
590	0	2019	Lancaster	250	4	1	1	0	0	1
590	0	2021	Lancaster	250	2	1	2	0	0	2
590	0	2022	Lancaster	250	1	1	0	0	0	0
595	600	2000	Schlumberger	250	23	2820	415	16	16	447
595	600	2001	Schlumberger	250	22	3541	291	6	1	298
595	600	2002	Schlumberger	250	21	3112	171	1	8	180
595	600	2003	Schlumberger	250	20	44	17	0	0	17
595	600	2016	Schlumberger	250	7	1	1	0	0	1
595	600	2019	Schlumberger	250	4	1	3	0	0	3
602	0	2016	Itron	250	7	4271	91	0	1	92
602	0	2017	Itron	250	6	4524	85	0	1	86
602	0	2018	Itron	250	5	8086	133	2	0	135
602	0	2019	Itron	250	4	11414	155	0	0	155
602	0	2020	Itron	250	3	21284	211	0	0	211
602	0	2021	Itron	250	2	22430	115	1	0	116
602	0	2022	Itron	250	1	8810	34	0	0	34
602	0	2023	Itron	250	0	2	0	0	0	0
603	0	2020	Itron	400	3	421	18	0	0	18
603	0	2021	Itron	400	2	380	7	0	0	7
603	0	2022	Itron	400	1	32	0	0	0	0
561	0	2021	American	250	2	6918	26	0	0	26
561	0	2022	American	250	1	6237	6	0	0	6
471	0	2010	American	425	13	73	30	1	0	31
510	515	1976	Rockwell	310	47	214	55	3	5	63
595	600	2004	Schlumberger	250	19	20	12	0	0	12
120	0	1980	Rockwell	175	43	951	83	6	1	90
520	0	1978	Rockwell	415	45	26	13	0	0	13
120	0	1997	Rockwell	175	26	123	55	4	1	60
510	515	1981	Rockwell	310	42	161	29	0	3	32
470	472	2001	American	425	22	46	39	3	0	42
120	0	1982	Rockwell	175	41	1088	81	8	1	90
120	0	1984	Rockwell	175	39	1353	93	10	2	105
125	0	1995	Rockwell	200	28	65	46	4	0	50
505	507	2012	American	1000	11	348	52	2	0	54
520	0	1988	Rockwell	415	35	36	15	0	0	15
140	0	1979	Sprague	175	44	118	22	0	0	22
480	486	1992	American	800	31	16	10	0	0	10
120	0	1968	Rockwell	175	55	51	28	1	0	29
140	0	1984	Sprague	175	39	627	69	1	9	79

Docket No. UG 490

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
470	472	1992	American	425	31	103	43	2	0	45
125	0	1999	Rockwell	200	24	127	21	0	0	21
130	0	1996	American	175	27	997	39	1	2	42
125	0	1994	Rockwell	200	29	363	25	0	0	25
480	486	1989	American	800	34	15	10	0	0	10
520	0	1979	Rockwell	415	44	50	24	0	3	27
470	472	1984	American	425	39	95	20	0	0	20
520	0	1980	Rockwell	415	43	39	31	2	0	33
125	0	1987	Rockwell	200	36	476	76	4	0	80
470	472	1982	American	425	41	10	8	0	0	8
470	472	1997	American	425	26	249	65	8	0	73
570	0	1993	Rockwell	275	30	44	15	0	1	16
470	472	2006	American	425	17	21	12	0	0	12
585	0	2000	Sprague	250	23	21	14	0	0	14
470	472	1985	American	425	38	12	9	0	0	9
470	472	1998	American	425	25	124	56	5	0	61
555	0	1980	American	310	43	36	32	2	0	34
555	0	1981	American	310	42	12	9	0	0	9
555	0	1987	American	310	36	21	14	0	0	14
585	0	1988	Sprague	250	35	161	22	0	0	22
520	0	1982	Rockwell	415	41	21	13	0	0	13
590	0	1988	Lancaster	250	35	58	17	0	1	18
125	0	1990	Rockwell	200	33	217	67	6	0	73
470	472	1999	American	425	24	166	67	6	0	73
125	0	1979	Rockwell	200	44	134	22	0	0	22
140	0	1972	Sprague	175	51	128	22	0	0	22
510	515	1986	Rockwell	310	37	9	10	1	1	12
510	515	1992	Rockwell	310	31	68	42	6	3	51
510	515	1993	Rockwell	310	30	65	31	1	2	34
570	0	1992	Rockwell	275	31	109	22	0	0	22

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Appendix B
Meter Families Not Conforming (To Be Removed Over 1 Year)

Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	% Not Conforming	PCC Reason
120	0	2012	Rockwell	175	11	1	0	0	0	0	Small Family
120	0	2013	Rockwell	175	10	1	0	0	0	0	Small Family
130	0	1994	American	175	29	2505	106	19	0	125	Determined
130	0	2013	American	175	10	1	0	0	0	0	Small Family
130	0	2022	American	175	1	1	10	4	1	15	Determined
450	0	2013	Schlumberger	400	10	1	0	0	0	0	Small Family
470	472	1989	American	425	34	18	17	2	0	19	Determined
470	472	2012	American	425	11	1	0	0	0	0	Small Family
475	0	1996	American	630	27	1	0	0	0	0	Small Family
560	0	2012	American	250	11	6	0	0	0	0	Small Family
560	0	2013	American	250	10	2	0	0	0	0	Small Family
561	0	1984	American	250	39	1	0	0	0	0	Small Family
570	0	2005	Rockwell	275	18	6	7	0	0	7	Small Family
570	0	2012	Rockwell	275	11	4	1	0	0	1	Small Family
570	0	2013	Rockwell	275	10	1	0	0	0	0	Small Family
570	0	2022	Rockwell	275	1	1	6	1	0	7	Determined
572	0	1999	Sensus	275	24	1	0	0	0	0	Small Family
572	0	2012	Sensus	275	11	3	1	0	0	1	Small Family
572	0	2013	Sensus	275	10	1	0	0	0	0	Small Family
595	600	2012	Schlumberger	250	11	1	0	0	0	0	Small Family
602	0	1997	Itron	250	26	1	0	0	0	0	Small Family
270	0	2000	Schlumberger	1000	23	17	2	0	0	2	Samples >50%
510	515	1984	Rockwell	310	39	12	2	0	0	2	Samples >50%
270	0	1998	Schlumberger	1000	25	16	7	1	0	8	Samples >50%
471	0	2012	American	425	11	9	1	0	0	1	Samples >50%
					Total	**2,612**					

CASE: UG 490
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 907

Confidential Responses to Data Request in Support Of Opening Testimony

April 18, 2024

Staff/Exhibit 907

STAFF EXHIBIT 907 IS CONFIDENTIAL AND SUBJECT

TO PROTECTIVE ORDER NO. 23-480

CASE: UG 490
WITNESS: JULIE DYCK

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1000

REDACTED
Opening Testimony
IT&S Projects, Cloud-based Software, Administrative and General Expenses

April 18, 2024

Docket No: UG 490

Staff/1000
Dyck/1

Q. Please state your name, occupation, and business address.

A. My name is Julie Dyck. I am a Senior Economist/Utility Analyst employed in the Energy Costs Section of the Rates, Safety and Utility Performance (RSUP) Program of the of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in exhibit Staff/1001.

Q. What is the purpose of your testimony?

A. My testimony details the recommendations by Staff regarding IT&S projects, cloud-based software, and administrative and general (non-labor) expenses.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/1002, comprised of Northwest Natural non-confidential responses to Staff data requests and Exhibit Staff/1003, which includes Northwest Natural confidential responses to data requests.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. IT&S Projects and Cloud-Based Software 2
Table 1: Intangible Software Plant Accounts 8
Table 2: IT&S Projects that go into place by the Test Year 9
Table 3: Contingency Funds 11
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Figure 1: OR Allocated FERC 921 Expenses 26
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Docket No: UG 490 Staff/1000
Dyck/2

ISSUE 1. IT&S PROJECTS AND CLOUD-BASED SOFTWARE

Q. Please summarize where NW Natural's IT&S Projects can be found.

A. In NWN Natural's Exhibit/700, Company witness Downing provides an overview of 11 separate Information Technology (IT) projects that are expected to be in service by the rate effective date of November 1, 2025. IT&S rate base expenses are found in FERC Accounts 303 (Miscellaneous tangible plant), 391 (Office furniture and equipment), and 397 (Communication equipment); this Testimony focuses mostly on amounts recorded in FERC Accounts 303. Although there are O&M related IT&S expenses that are in additional FERC accounts, they are analyzed by different Staff in their respective testimonies. For example, I analyze Office supplies and expenses (FERC 921) in Issue 3 that contain IT&S related O&M expenses.

Q. Detail how IT&S project costs are split.

A. IT&S project costs are split between capital and O&M. The Company's Capital Asset Policy outlines what is considered capital vs O&M and general guidance is included in the Company's Project Management Handbook.[1] IT Software (on-premises, cloud licensing, and maintenance) and hardware (initial purchase and on-premises maintenance) are typically capital meanwhile project management costs are typically charged to O&M expense accounts.

IT Projects (electronic equipment and computer software/hardware equipment) have continued to be a main driver of NW Natural's capital expenditures. According to NW Natural, "[t]hese costs have experienced an

[1] Staff/1002, DR 162 Attachment 1, Project Management Handbook, 22-23.

increase due to cybersecurity threats and other increasing demands and complexity in the IT arena."[2] NW Natural explains that another driver of capital costs is that the cost of first-year maintenance paid as part of the software purchase is capitalized, as are additional costs related to changes in system design and/or system selection during implementation and the development of process manuals and documentation.[3]

Q. Distinguish between the terms cloud-based software and IT&S investments.

A. Cloud-based software and non-cloud-based software fall under the umbrella of IT&S investments.[4] Migration to the cloud is sometimes necessary to avoid transitioning to a new software system or tool, and cloud-based software can be more quickly updated. "Providers like Amazon Web Services (AWS), Microsoft Azure, and Google Cloud Platform have become essential partners for businesses of all sizes."[5] The Company explained five detailed ways that cloud-based and non-cloud-based options differ. Cloud based solutions:

1. Are hosted and managed by third-party providers as opposed to on-premises solutions that have Company owned hardware and equipment.
2. Are more flexible and scalable as there is not a need to usually invest in additional hardware.

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2 NWN/1400, Davilla/27.
3 Staff/1002, NWN Response to SDR 80 attachment 1 page 9-10 of 13.
4 Staff/1002, NWN Response to DR 156 (pdf). See also NWN/700, Downing/8-11 for a detailed discussion of the differences between the two basic IT&S hosting options: cloud-based and on-premises.
5 Staff/1002, NWN Response to DR 156 Attachment 1 (pdf).

3. Create an incremental O&M increase that escalates through time because businesses only pay for the resources they use on a monthly or yearly basis. Therefore, the programs can be capitalized but the depreciation is approximately five years which often cause a lag in recovery.
4. Tend to be more reliable and secure as the cloud providers invest heavily in security measures and disaster recovery protocols.
5. Typically have automatic upgrades and updates for hardware and security, which reduces IT burden.

Q. Was cloud-based software addressed in previous GRCs?

A. Yes, it was discussed in NW Natural's two most recent rate cases, UG 435[6] (2022) and UG 388 (2020).[7] In UG 435, the Commission adopted a stipulation under which the Horizon 1 cloud-based assets are amortized into rates over a ten-year life.[8] In that stipulation, NW Natural agreed that if the asset was removed from service in less than ten years, the Company would apply the modified blended treasury (MBT) rate to the remaining balance of the asset and defer the difference between the Company's cost of capital and the MBT rate until such time that general rates are changed.[9] In UG 388, while no IT-related issues were in the final settlement, Staff did initially propose the

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6 Staff/1002, NWN Response to DR 156 Attachment 1 (pdf).
7 See UG 388, NWN/600, Downing/11-14, 16-27, 39, 50; UG 435 NWN/1600, Downing/22.
8 *See also In the Matter of Northwest Natural Gas Company, Application for Accounting Order for Approval of Depreciation and Amortization of Rates for Investment in Certain Software*, UM 2215, Order No. 23-079 (March 10, 2023) (Accounting order authorizing NWN to use ten-year amortization period for cloud-based asset and implementation costs).
9 *In the Matter of Northwest Natural Gas Company, Request for a General Rate Revision*, UG 435, Order No. 22-388, Appendix A Page 9 of 37.

reduction of support for Microsoft Office 365 and IT&S staffing. It appears that Staff had no issues with NWN rate basing various amounts from IT projects in UG 435 and UG 388.

Q. Does NW Natural include cloud-based assets in its rate base for this GRC?

A. Yes. Staff is also under the impression that licenses fees and hosting fees are not included in these totals. While implementation costs can be capitalized, license fees can only be capitalized under certain conditions, and hosting fees and maintenance/support are O&M expenses. Staff asks that the Company specify in their Reply Testimony whether there are license or hosting fees included in rate base. If these fees are included, the Company should explain what licensing fees or hosting fees are included as part of rate base and explain the rationale.[10] If Staff's current assumption that there are no such fees is incorrect, Staff will update its recommendation in subsequent testimonies.

Q. Please explain NW Natural's rationale for including cloud-based assets in rate base.

A. The Company explains that whether "Cloud Computing Arrangements" meet the criteria for capitalization is determined under accounting rules. FERC (Regulatory) and GAAP do not differ on the types of costs that can be capitalized or expensed for Cloud Computing Arrangements. NW Natural states that "FERC made a final ruling on ASU 2018-15: Customer's Accounting

[10] This was an issue that was brought up in Robert Young's testimony in Exh 2100 in UE 416, PGE's previous GRC.

for Implementation Costs Incurred in a Cloud Computing Arrangement that is a Service Contract to all jurisdictional public utilities and licenses, natural gas companies and centralized service companies. For regulatory accounting, capitalized implementation costs should be recorded as utility plant assets in FERC Account 303 (Misc. intangible plant - computer software) and should be amortized over the term of the associated cloud computing arrangement in FERC Account 403 (Depreciation expense)."[11]

Q. Please describe how the IT&S individual business unit develops their forecast for capital.

A. The Company and each business unit use a bottom-up approach which is typically driven by business needs. Business units coordinate with the Portfolio Management Committee (PMC) to discuss, review, prioritize, and approve funding for projects. Following approval, projects are included into the forecast cycle.

However, the Company's strategy for cloud-based solutions was developed in partnership with Deloitte.[12] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[13]

[11] Staff/1002, NWN Response to DR 416 (pdf).
[12] NW Natural/700, Downing/8.
[13] Staff/1003, NWN Response to CONF DR 168 Attachment 1 Page 7 of 21. See also Staff/1002, NWN Response to DR 162 Attachment A (pdf), Page 5 and page 21 are included as an attachment to show the capital planning process in more detail. Page 37 of 50 details that Planview is NW Natural's Project Portfolio Management (PPM) tool. Projects are required to leverage Planview for stage gates, status reporting, schedules, resource management and budgeting, as it serves as the source of truth for much of NWN's rates reporting.

Q. What is the Commission historical treatment of IT capital investment?

A. In previous rate cases, Staff has performed prudence reviews and examined whether the investment satisfies the "used and useful" criteria to determine whether IT investments are includable in rates.[14] Past Staff testimony has focused on a few IT&S projects that were cause for concern. It is also important to acknowledge that there is a knowledge asymmetry that exists between IT&S Staff at the Company and OPUC Staff when it comes to analyzing whether expenses were prudent. This is usually the case with more specialized expense categories but is also mitigated by Staff issuing multiple DRs, reading past testimonies, participating in workshops, and covering the same issue in multiple GRCs.

Q. How did Staff review and analyze the proposed IT projects?

A. Staff initially reviewed Mr. Downing's testimony, noting in particular the Company's statements regarding the current age and cybersecurity vulnerabilities of certain legacy information systems the "IT Projects" will replace. Staff issued a number of data requests to gain a better understanding of the underlying functionality of the proposed projects, why they are needed now, and what steps the Company took to achieve least cost/least risk solutions.[15]

Q. Please detail the IT&S projects that are requested for UG 490 and expected to go into place by the Test Year.

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[14] See *In the Matter of PacifiCorp Request for a General Rate Revision,* Docket No. UE 246, Order No. 12-493 at 25 (Dec. 20, 2012).

[15] Staff issued DRs 156-187 and 408-428 on IT&S related expenses.

A. Rate base IT&S expenditures are found in the "Intangible" and "General" categories of utility plant in service. The Intangible plant is fully comprised of IT&S capital expenditures. IT&S expenditures within the General category are isolated to FERC Accounts 391 for Computers, Computer Horizon, and Computer Bloodhound.[16] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**[17] Average rate base balances were calculated using monthly forecast amounts to construct a 10-month AMA for all rate base components.[18] Table 1 shows a list of the plant accounts included. However, Staff's analysis primarily focuses on the IT&S Projects that are listed in Table 2 and described in NWN/700, as these are new projects that are expected to be in place by the Test Year.

TABLE 1: INTANGIBLE SOFTWARE PLANT ACCOUNTS

FERC	Description
303.1	Computer Software
303.2	Customer Information System
303.3	Industrial & Commercial BIL
303.4	CRMS
303.7	Cloud-Based Software
303.11	Computer SW Horizon
303.12	Computer SW Bloodhound
303.71	Cloud-Based SW Horizon

16 Staff/1002, NWN Response to DR 411 (pdf).
17 See CONF workpaper on Rate base and accumulated depreciation in the rate base net plant tab; see also Staff/1002, NWN Response to DR 411 Attachment 1 (excel). While the information included in the response to DR 411 Attachment 1 is non-confidential, Staff labeled this statement as confidential to err on the side of caution since the other workpaper is conf.
18 See NWN/1700, Walker/29.

303.71	Cloud-Based SW Bloodhound

TABLE 2: IT&S PROJECTS THAT GO INTO PLACE BY THE TEST YEAR

Projects	Capital Investment	Incremental O&M[19]	Cloud Based
IQGeo Upgrade Project (Field and Web Mapping)	$1.71M System ($1.5M Oregon Allocated)		Y
MapFrame Replacement Project (General Map viewer)	$5.5M System ($4.8M)		N
Composition 2.0 Project (Customer Bills)	$4.4M System ($3.9M)	$87K ($77K OR Allocated) for hardware and software licensing	N
Genesys Re-platform Project (Call Routing Software)	$2.3M System ($2.0M)	$289K ($254K)	Y
Start-Stop-Transfer Project (Relocate Service)	$2.7M ($2.4M)		N
Clevest Optimization Project (Mobile workforce management software)	$7.5M ($6.6M)		N
Identity Governance and Administration Automation Project (Secure onboarding and offboarding)	$3.0M ($2.6M)	$113K ($99K for software licensing)	Y
Telemetry Refresh Projects (Remote monitoring and control sites)	$6.8M ($6.0M). Of this amount, $4.1M ($3.6M) is associated with the One Pacific Square (OPS) 4-wire sites.[20]		N
Utilities International Planner Re-platform Project (UI Planning System)	$1.8M ($1.6M)	$208K ($183K)	Y
PowerPlan Project (Capital Settlement Process)	$1.7M ($1.5M)		N
SAP Treasury Project	$2.9M ($2.5M)		N
Total	$40.31M ($35.4)	$697K (613K)	

Q. Do any of the projects have prepayments?

[19] These amounts are viewable in IT&S forecast tab and show the amounts that are attributable to things other than inflation.
[20] The Company's former headquarters.

A. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[21] "For each of the contracts entered into for the IT&S projects included in Exhibit 700, the payment terms were for 30 days after receiving an invoice (i.e., "Net 30")."[22]

Q. Which projects are considered out of service in the Test Year?

A. The Genesys and Utilities International (UI) Planner are two projects that are going out of service and will be re-platformed. The remaining rate base amounts as of October 1, 2023, are -$3,404,683 and -$331,789, respectively. NWN did not include these projects in its forecasted retirements and will therefore update this in its Reply Testimony.[23]

Q. Have these projects been moved into a regulatory asset account?

A. No. "The Company uses the Group Depreciation Method which does not depreciate these assets individually, the total cost of the group is spread out over the useful life of the entire group. Through the depreciation study process the Company reassess the useful life and salvage value of the assets in each group, including retirements, and adjustments to depreciation rates may be made accordingly."[24]

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21 Staff/1003, NWN Response to CONF DR 414 Attachment 1 (excel).
22 Staff/1002, NWN Response to DR 414 (pdf).
23 Staff/1002, NWN Response to DR 415 (pdf).
24 Staff/1002, NWN Response to DR 415 (pdf).

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Staff/1000
Dyck/11

Q. Does Staff have any adjustments before discussing each of the individual IT Projects?

A. Yes. Out of the 11 projects referenced above in Table 2, only eight of those projects have contingency funds. Staff recommends removing the contingency funds of five projects,[25] which results in a total adjustment to NW Natural's proposed rate base of ($1,649,887), Oregon allocated. Of the remaining three projects below, two projects have already used them, one project I am recommending to be removed in its entirety, and it was stated that other projects are not expected to use their contingency funds.[26] Of the eight projects below, one is supposed to be in service 1/24, one is supposed to be in service 6/24, and the other six are supposed to be in service September or October of 2024. Therefore, if the contingency funds have not been used yet, they are unlikely to be used.

TABLE 3: CONTINGENCY FUNDS

Project	Project #	Contingency		Contingency Used
		System Level	Oregon Allocated	
SAP Treasury	I-202722	$ 100,000	$ 87,890	$ 100,000
Comp 2.0	I-202725	$ 262,180	$ 230,430	$ -
Identity Governance & Admin	I-202723	$ 200,000	$ 175,780	$ -
IQGeo Upgrade	I-202804	$ 100,000	$ 87,890	$ 100,000
Clevest	I-202721	$ 645,038	$ 566,924	$ -
TSA	I-202667	$ 430,000	$ 377,927	$ -
MapFrame	I-202862	$ 340,000	$ 298,826	$ -
Genesys	I-202840	$ 200,000	$ 175,780	$ -

[25] This excludes SAP Treasury, IQ Geo Upgrade, and Genesys. The reason for the exclusion of Genesys is described later. The other two projects have already used their contingency funds.

[26] Staff/1002, NWN Response to DR 185 Attachment 1 (excel) and NWN Response to DR 424 (pdf).

Q. What is IQGeo Software and does Staff have any concerns with including costs of this investment in rate base?

A. IQGeo Software is a web mapping tool. NW Natural states it uses mapping tools to provide field and office personnel with visual online and offline representations of NW Natural facilities and assets, which they use for various business purposes, including inspection compliance programs.[27] NW Natural has upgraded the IQGeo software because it is no longer fully supported, and the project will re-platform the software to a new more cybersecure cloud environment. Staff has reviewed the rationale and costs of the investment and has identified no concerns. NW Natural anticipated that this project will be online in January 2024.

Q. What is MapFrame and does Staff have concerns with including this investment in rate base?

A. MapFrame transitions away from an existing end-of-life software system that has not received a software update from its developer since 2015. Staff reviewed the costs of the project and has not identified costs that should be disallowed. NW Natural anticipates that this project will be online by the end of Summer 2024, so the project should be used and useful before the effective date of rates filed in this case.

Q. Does Staff have any concerns with the Composition 2.0 Project?

A. No. The Composition 2.0 Project modernizes the Company's electronic and printed documents for customers, including bills, notices, letters, welcome

[27] NW Natural/700, Downing/15.

packages, and refund checks. The customer bills (Composition 2.0 project) and Start-Stop-Transfer Project (discussed below) seem important and a good use of funds as there was a big difference in the change of bill formats and being able to automatically transfer account info to online forms. NW Natural anticipates this project will be on-line in September 2024. Staff will monitor the project to make sure it is used and useful prior to the November 1, 2024 effective date for rates in this case.

Q. What is the Genesys Re-platform project?

A. Genesys is the Company's existing on-premises advanced call routing software provider. The Genesys Re-platform Project transitions the Genesys call routing solution to a cloud environment, in response to the impending termination of Genesys' software support for the PureConnect platform by the software provider.[28] Genesys is phasing out the availability of and support for the PureConnect system, first by ceasing to offer new support agreements in January 2024, and then by fully ceasing support and operation of the system on July 31, 2025.[29]

Q. Does Staff have concerns with this project?

A. Staff is concerned that the Genesys re-platform was completed earlier than it needed to be. Full support and operation of the System was guaranteed until July 31, 2025, but the project is underway and is on track to be placed in service by October 2024.

[28] NW Natural/700, Downing/24.
[29] NW Natural/700, Downing/24-25.

Staff believes this project has been rushed to ensure that it was in place before the rate effective date even though the previous call routing platform would have been fully supported through July 31, 2025. Notably, other software that NW Natural is replacing has been unsupported for years. For example, the IQGeo software has been unsupported since June 2022, MapFrame has not been updated since 2015, and UI Planner is no longer supported as of 2023. Notwithstanding, NW Natural was able to wait until 2024 to transition to a cloud-based solution for these applications. However, it is unclear what the Company means by "fully ceasing support and operation of the system" and whether the System could continue to operate after July 31, 2025.

Staff believes it would have been prudent for NW Natural to wait to implement this change to moderate the cost impact of these significant IT investments in this rate case. Therefore, Staff recommends removing the total Genesys re-platform project from rate base because at the time it was an imprudent expense to make given the longevity of the Genesys call routing software. This is a total adjustment of ($2 million) to rate base, Oregon allocated, and ($254,000) in incremental O&M for software licensing.

Q. What is the Start-Stop-Transfer Project and has Staff identified any concerns with including the costs of this project in rate base?

A. The Start-Stop-Transfer Project provides a new web-based tool that will allow customers to initiate, terminate, or relocate their service with NW Natural using

the Company's website.[30] Staff believes this project will be beneficial to ratepayers and has identified no costs that should be disallowed, other than the contingency fund. NW Natural currently anticipates that this project will be on-line in October 2024.[31] As this is right before the effective date of rates from this GRC, Staff will monitor the progress of this project as the case goes on.

Q. What is the Clevest Optimization Project and has Staff identified any issues with the project?

A. Clevest is NW Natural's mobile workforce management software used to schedule, dispatch and complete all work in the field—ranging from emergency response to routine maintenance work. Clevest replaced NW Natural's previous end-of-life application, PragmaCad ("P-CAD"), was developed and implemented as part of the Horizon 1 Project, and has been in service since 2022.[32] The Clevest Optimization Project is an incremental effort to improve the Clevest mobile work management system, including (1) resolving post-deployment issues identified in the product's performance ("stabilization") and (2) adding new functionalities that were initially not included but, following the product's launch, turned out to be critical ("optimization").[33]

Although Staff has no monetary adjustment, Staff has identified a concern. The Company states that since Clevest was fully deployed in 2022 it has had difficulty accommodating the complexity of actual operations, referencing lag

30 NW Natural/700, Downing/26.
31 NW Natural/700, Downing/29.
32 NW Natural/700, Downing/29.
33 NW Natural/700, Downing/30.

times between 3-5 minutes and up to 30 minutes. The Optimization at issue in this GRC is necessary because the Company initially determined that certain features and functions were not essential and deprioritized. Staff recommends that the Company spend more time in a training environment to prevent situations like this from occurring, which in the end can increase the number of rate impacts for customers and the magnitude of those impacts.

Finally, NW Natural projects that the Clevest Optimization Project will be deployed in October 2024,[34] which is right before the rate effective date for this GRC. Accordingly, Staff will continue to monitor this project to ensure it is used and useful before the investment is placed in rate base.

Q. What is the Identity Governance and Administration (IGA) Automation Project and has Staff identified any concerns?

A. The IGA Automation Project involves implementing a comprehensive new software solution to track and manage the security access and identity management for Company personnel, particularly during onboarding, transfers, and offboarding. The Company testifies that currently, security access and other privileges are handled manually, with no centralized control point. As a result, there is currently no mechanism to certify that an individual's access to security and other functions has been removed following offboarding or other role changes.[35] The Company anticipates the software will be in service by June 2024.[36] Although Staff does not have a particular monetary adjustment to

[34] NW Natural/700, Downing/36.
[35] NW Natural/700, Downing/37.
[36] NW Natural/700, Downing/41.

the project totals, Staff is concerned that the process to acquire the IGA Automation project was convoluted with multiple consultants, including Forrester, with whom they have a subscription, and Integral Partners.[37] For other projects, like Clevest, the Company committed a dedicated business lead and project manager to focus on the work. Staff is generally concerned about the increase from $2.7 million in UG 435 to $9.1 million in UG 490 on consultants.[38] Staff is continuing to investigate this issue. Staff asks that the Company confirm whether this project and supplier and the other projects and suppliers were contracted are a result of an RFP.

Q. What are the Telemetry Refresh Projects and has Staff identified any issues?

A. The Telemetry Refresh Projects replace outdated monitoring and control equipment. The majority of the costs are associated with replacing telemetry equipment (OP 4-Wire sites) that transmitted to the basement of NW Natural's former headquarters, One Pacific Square, in order to avoid the need to renew the OPS basement site lease. NW Natural anticipates the projects will be on-line in October 2024.[39] Staff did not find any issues with these projects at this time but will monitor to ensure the projects are used and useful before they are included in the Company's rate base for this GRC.

Q. What is the Utilities International (UI) Planner Re-platform Project and has Staff identified any issues?

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37 Staff/1002, NWN Response to DR 184 (pdf).
38 Staff/1002, NWN Response to DR 159 Attachment 1 (Excel).
39 NW Natural/700, Downing/43-44.

A. The UI Planner is NW Natural's corporate financial and regulatory finance planning system used to perform complex, iterative forecasts and problem-solving.[40] The Company's legacy version of UI Planner was first implemented in 2014 and will no longer be supported by the software provider after 2023.[41] The Company anticipates that the project will be online in August 2024. Staff has not identified issues with the project but will monitor to be sure it is used and useful before it is included in rates.

Q. What is the PowerPlan Project and has Staff identified issues with this project?

A. The PowerPlan Project transitions a key accounting function, known as the capital settlement process, from the Company's existing PowerPlan tool and into the broader SAP ERP system. The capital settlement process tracks costs accumulated under work orders and projects and allocates those costs to various accounts in PowerPlan.[42] The Company states the transition into the broader SAP Enterprise Resource Planning (ERP) System will improve the accuracy of the Company's capital projects tracking and reporting data. Staff has identified no issues with the project. The Company anticipates the project will be complete in October 2024, so Staff will monitor to ensure it is used and useful prior to the rate effective date.

Q. What is the SAP Treasury Project and has Staff identified issues?

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40 NW Natural/700, Downing/44-45.
41 NW Natural/700, Downing/45.
42 NW Natural/700, Downing/45.

A. The SAP Treasury Project implements a software tool to automate and manage the Company's treasury functions—such as financial tracking and payment approval systems. The new tool replaces previous manual spreadsheet-based processes and according to the Company provides consolidated and comprehensive visibility into the Company's financial risk management using the necessary subset of SAP's "Treasury Track" software functionalities.[43] The SAP Treasury Project was placed in service in October 2023.[44]

Q. Does Staff have comments regarding the IT&S FTE request?

A. Yes. Staff has comments below although the dollar value adjustment is included in Stephanie Yamada's testimony regarding labor, wages and salaries, and FTE.

Q. How many IT&S positions are being requested?

A. NW Natural is requesting eight new IT&S positions aka full-time employees (FTEs). Four of the eight FTEs[45] are essential to support Horizon 2: Vista (H2: Vista). The other four FTEs are needed to support NW Natural's Supervisory Control and Data Acquisition (SCADA) telemetry systems, gas/pipeline control operations, and identity governance administration.[46]

Q. Should the Company be allowed to recover the costs for the H2: Vista related positions in this GRC?

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43 NW Natural/700, Downing/48.
44 NW Natural/700, Downing/50.
45 NW Natural/700, Downing/50-55
46 NW Natural/700, Downing/53-55.

A. No. H2: Vista will comprehensively update the customer information system (CIS) but no cost recovery for the investment is requested in UG 490 because it will not be online by the rate effective date. The Company states cost recovery for incremental employees is appropriate even though the investment will not be in rates because the Company intends to immediately begin recruiting three of the four positions and expects all four positions to be hired prior to the rate effective date (i.e., November 1, 2024), although the exact dates will depend on finding qualified candidates.

H2: Vista is replacing NW Natural's legacy, 26-year-old CIS.[47] Staff expects that current CIS employees will be cross trained for H2: Vista, as this is replacing the legacy system. Those employees that were working on CIS-related projects before are better equipped to learn a new system. In addition, NW Natural's IT&S FTE count in 2023, when completing the larger Horizon 1 program was 104, whereas their UG 490 request is 116. So even if all eight positions are approved, the Company's total IT&S FTE are likely to be around 112, which is four less than their request, since they are unlikely to fill all positions.

Moreover, H2: Vista is the second phase of a two-phase project. Horizon 1 was approved for recovery in UG 435 and successfully implemented on time and on budget. H2 will comprehensively update the customer information system (CIS) but no cost recovery is requested in UG 490.

[47] Staff/1002, NWN Response to DR 357 (pdf).

In 2023, NW Natural was able to complete the work of Horizon 1 while being "understaffed" from their previous request. Therefore, Staff proposes to remove the dollar value for the four positions. See Table 4 which shows the NW Natural's FTE count for IT Staff.

TABLE 4: FTE COUNT OF IT STAFF[48]

	2018	2019	2020	2021	UG 435 Request	2023	UG 490 Request
FTE	77	84	92	90	92	104	116

Q. Are the four positions for H2 Vista expected to be included in the deferral that they will file later this year?

A. Yes. "The Company expects to include the costs of these FTEs in the deferral until such time base rates are updated on November 1, 2024, at which point the Company will recover their costs in base rates. The cost of these FTEs is estimated to be incurred prior to the Test Year, during the Test Year and will be ongoing costs." The Company's currently plans to file the Horizon 2, or H2: Vista, deferral application in the third quarter of 2024. The Company will update its plans in its Reply Testimony.[49]

Q. Please summarize Staff's adjustments for IT&S costs.

A. Staff recommends a total adjustment of ($3.7 million) to rate base, which is comprised of ($1.7 million) in contingency funds, ($2 million) of capital costs

[48] Staff/1002, NWN Response to DR 160 Attachment 1 (excel).
[49] Staff/1002, NWN Response to DR 419 (pdf).

and an adjustment of ($254 thousand) to Test Year O&M costs for the Genesys Re-platform Project. Staff's FTE adjustment is included in Staff Opening Testimony for Stephanie Yamada in Exhibit 2000. My recommendations may change based on further review and as informed by the testimonies offered by other parties.

In addition, Staff intends to follow-up with data requests on the following concerns and asks that the Company address these concerns in their Reply Testimony.

1. Are licensing fees or hosting fees included as part of rate base?
2. Can Genesys continue to operate after July 31, 2025?
3. What is the company's policy for spending time in a training environment for IT projects and are they open to amending the time spent in a training environment?
4. Can the Company confirm IT projects and suppliers were contracted as a result of an RFP?
5. What are their plans for including Genesys and Utilities International (UI) Planner in their forecasted retirements and how will that impact their Test Year request?
6. Is there an update on the planned deferral for Horizon 2 program costs?

Docket No: UG 490 Staff/1000
Dyck/23

ISSUE 2. ADMINISTRATIVE AND GENERAL (NON-LABOR) EXPENSE

Q. Please describe the expenses included in this issue.

A. I review non-labor Administrative &General (A&G) expenses and credits recorded in FERC Accounts 921 (Office Supplies and Expenses, 922 (Administrative Expenses Transferred-Credited), 930.2 Miscellaneous General Expenses) and 931 (Rents). Other Staff review other categories of A&G expense such as 924 (Property Insurance), 925 (Injuries and Damages), and 926 (Employee Pensions and Benefits) and their conclusions and recommendations can be found in Exhibit 700 and 1500.

Q. Does the Commission Staff have a standard for how A&G expenses are treated for ratemaking purposes?

A. Expenses are reviewed for reasonableness and appropriate use. Typically, Staff will evaluate the reasonableness of costs by comparing the Company's forecasted costs to the Base Year actuals, a three-year historical average of actual costs, a review of transactional details, and consideration of any trends or changes that may impact the Company's Test Year expense. The Company uses discrete internal "Cost Element" codes to book a range of administrative and general (A&G) expenses into FERC accounts. Staff elicits information regarding the expenses through Standard Data Requests and Data Requests issued throughout the GRC.

Q. What is NW Natural's Test Year proposal for the A&G expenses?

A. NWN is proposing to increase non-labor administrative and general expenses (in FERC 921, 930, and 931) from $54.8 million in the Base Year to $63.8

million in the Test Year. This represents an increase of $9 million, or 16 percent. This increase in expense outpaces the inflation over the same period and is mostly attributed to FERC 921. The following individual FERC account balances were proposed for the Test Year:

FERC 921 (Office Supplies) - NWN is seeking an increase of $8.1M.[50]

FERC 922 is a credit increase.

FERC 930 (Misc General) - NWN is seeking an increase of $417K.

FERC 931 (Rents) - NWN is seeking an increase of $406K.

Q. How did NWN escalate costs from the Base Year to the Test Year.

A. "The Company escalated general non-payroll costs using year-over-year rates of change in the forecast of the West Region Urban CPI as reported in the September 2023 Oregon Economic and Revenue Forecast, published by the OEA. These escalation factors were applied on January 1, 2024, and January 1, 2025 The Company also identified several items where the growth projection was greater or lesser than using CPI and adjusted these items with their specific increase or decrease."[51]

Q. What does Staff recommend for an escalation factor?

A. It is Staff policy to use the Consumer Price Index – All-Urban Consumers for the U.S. (CPI, Urban U.S.) as published by the State of Oregon Office of Economic Analysis for year over year escalation. The escalation factors used in the Company's filing are greater than those used by Staff. Staff proposes an

[50] Staff/1002, NWN Response to SDR 58 Attachment 2 (excel).
[51] NWN/1400 Davilla/8.

adjustment to use the most recent All-Urban CPI as reported in the March 2024 Oregon Economic and Revenue Forecast (2.7 percent for 2024, 2.0 percent for 2025).[52] In its Opening Testimony, the Company uses 3.6 and 2.9 percent. It is worth noting that even the Western CPI has come down in the March OEA forecast compared to the September values used by the Company in their OT.

Q. Please describe Staff's analysis of NW Natural's proposed Administrative and General expenses?

A. Staff reviewed the corresponding sections of the Company's Application, reviewed the responses to the Standard and Staff DRs[53] pertaining to Admin and General expenses, and analyzed the corresponding transactional data. My analysis focuses on historical A&G expense trends, transactional detail, and NWN's proposed escalation adjustment to non-labor A&G expense. Other Staff reviewed the remaining adjustments, and their conclusions and recommendations regarding their analyses can be found in their testimony.

Q. Describe the Company's proposed Test Year expense for FERC 921 (Office Supplies and Expense). [54]

A. The largest components of this IT&S O&M Expense increase are addressed in NWN/700 and NWN/800 as most are related to IT&S related costs.[55] Figure 2

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52 https://www.oregon.gov/das/oea/Documents/OEA-Forecast-0324.pdf

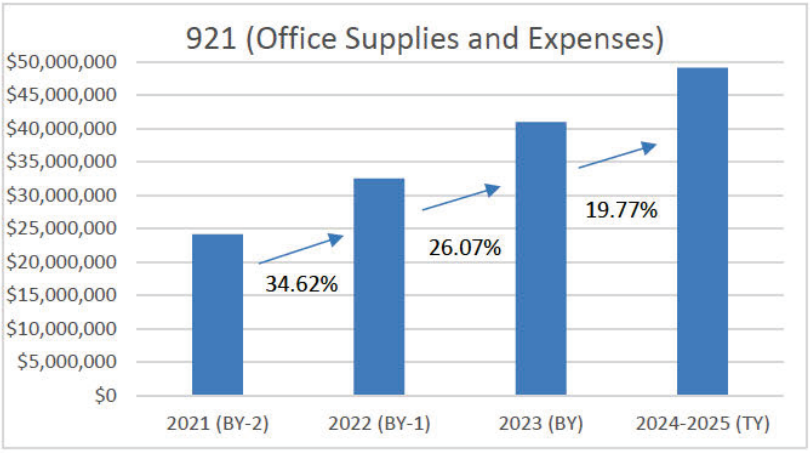
53 Staff DRs 200-202 and 425-428

54 It is worth noting for future Staff to reference that "this adjustment could have been performed more clearly in the workpaper to make reviewing easier." See Staff 1002, NWN Response to DR 408 (pdf) and DR 409 (pdf). For example, "IT&S adjustments were made to increase the total IT&S Test Year amount by $7.7M. How the expenses were allocated to each month in the workpaper was not an emphasis, so the Company spread those expenses equally to each month."

55 Despite the Highly Confidential mention above, all of the material below is non-confidential.

shows the large increase year over year as requested for new expenses such as software and hardware maintenance, legal fees, etc.[56]

FIGURE 1: OR ALLOCATED FERC 921 EXPENSES

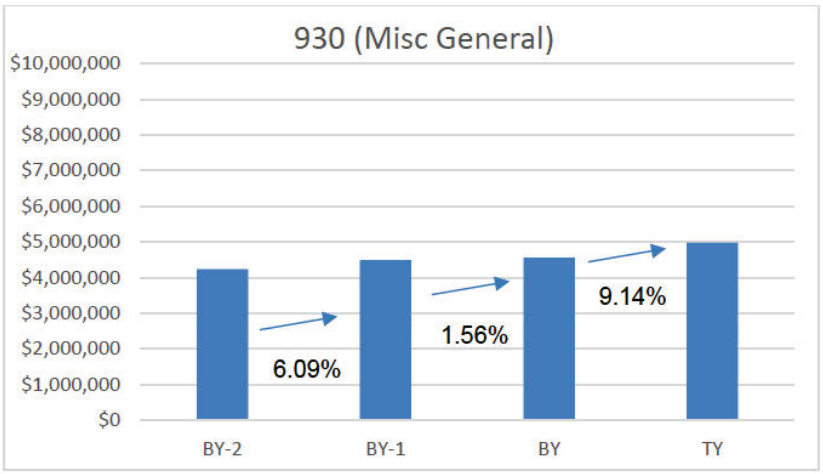


Q. How did the Company arrive at its forecast for general miscellaneous A&G expense recorded in FERC 930?

A. The Company's Test Year FERC 930 expenses are based on escalation; there are no new expenses.

[56] See Exh 1400 OM Model Workpaper_Non-Confidential, tab Dept Non-Payroll Forecast.

FIGURE 2: OR ALLOCATED FERC 930 EXPENSES



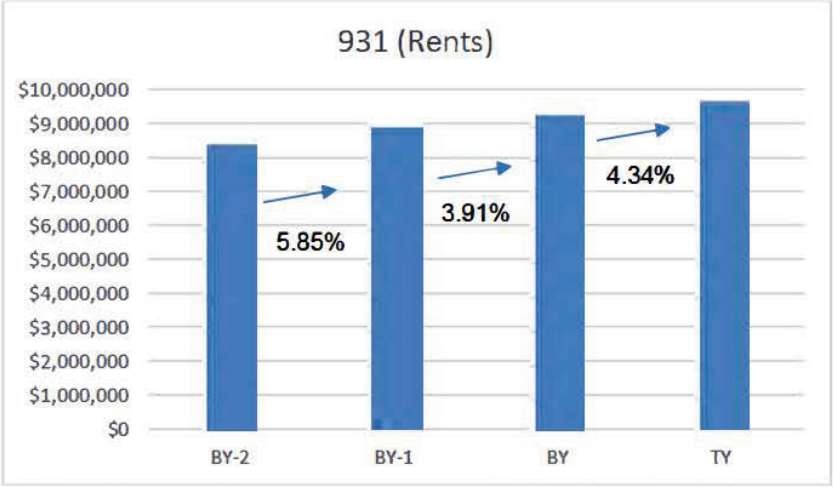
Q. How did the Company forecast its expense for FERC 931 (Rents).

A. The Company states that "An escalation factor should only be relied on where costs are unknown or otherwise fail to be indicative of future costs."[57] One line item in FERC 930 that the Company calls out specifically where this is not the case is for the contracted headquarters lease expense and tenant improvement amortization. As a result, an adjustment was made to reduce what the Test Year expense would have been as a result of inflation values used by the Company. The total expense adjustment decrease in the Test Year is $186 thousand and the OR allocated amount after administrative transfer is $107 thousand as a result of the above line item. Other rents are still expected to increase and therefore, overall FERC 931 costs increased modestly.[58] On the one hand, for the other rent expenses, Staff believes we should not assume that they are increasing at the CPI but given that the

[57] NWN/1400, Davilla/9.
[58] NWN/1400, Davilla/9.

allowable increase, as mandated by SB 608 (2019) and SB 611 (2023), and as calculated by the Oregon Department of Administrative Services (DAS) for 2024 is 10 percent,[59] Staff does not have an additional adjustment (beyond updated escalation figures) to FERC 931.

FIGURE 3: OR ALLOCATED FERC 931 EXPENSES



Q. Does Staff have adjustments to any of the above accounts?

A. Yes. Staff witness Paul Rossow recommends an adjustment to expenses in FERC accounts 816-930 of ($324,660) to remove fifty percent of expense for items classified as meals and entertainment. Most of this expense is in FERC Account 930. It is also worth noting that there is an additional $36,527 in First Class airfare that is also addressed in Paul Rossow's testimony. I have additional adjustments beyond what Paul Rossow has to FERC Account 930, as shown in Table 5 below.

[59] https://oregoneconomicanalysis.com/2023/09/26/oregon-maximum-rent-increase-2024-10-0/

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TABLE 5: FERC 930 EXPENSES TO BE SHARED[60]

Cost Center	Cost Center	GL Account	GL Account	FERC	Test Year Request	Sharing
10768	CORP SECRET-MISC GE	613200	BUSINESS TRAVEL	930	$78,562	$39,281
10768	CORP SECRET-MISC GEN	613100	CONFERENCE TRAVEL	930	$5,051	$2,526
10768	CORP SECRET-MISC GEN	601100	EDUCATION	930	$29,689	$14,845
10768	CORP SECRET-MISC GEN	604800	LAUNDRY	930	$244	$122
10768	CORP SECRET-MISC GEN	601500	MILEAGE REIMBURSE	930	$1,603	$801
10768	CORP SECRET-MISC GEN	603000	OFFICE SUPPLIES	930	$4,612	$2,306
10768	CORP SECRET-MISC GEN	602100	OTHER CONTRACT WORK	930	$1,275	$637
10768	CORP SECRET-MISC GEN	602466	P CARD UNCODED CHARG	930	$39	$20
10768	CORP SECRET-MISC GEN	604700	PARKING	930	$819	$410
10768	CORP SECRET-MISC GEN	606200	PERMITS AND FEES	930	$2,749	$1,374
10768	CORP SECRET-MISC GEN	602800	POSTAGE	930	$77	$39
10768	CORP SECRET-MISC GEN	605100	PROFESSIONAL SERVICE	930	$261,592	$130,796
10768	CORP SECRET-MISC GEN	602700	TELEPHONE	930	$5,454	$2,727
10768	CORP SECRET-MISC GEN	612200	TRAVEL IN TERRITORY	930	$32,736	$16,368
Total Adjustment						**$212,252**

Q. Is there a history of decisions in favor of the 50/50 sharing of costs between shareholders and ratepayers for other expenses?

A. Yes. Staff follows this guidance for the following expenses, Directors and Officers (D&O) liability insurance,[61] meals, entertainment, gifts, airfare, travel, lodging, awards,[62] office refreshments, catering, promotional items,[63] and bonuses and incentives.[64]

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60 These can be found in UG 490 - Exh. 1400 -OM Model Workpaper_Non-Confidential in the Dept. Non-Payroll tab.

61 In UE 197, the Commission adopted Staff's principal that D&O insurance should be shared equally between shareholders and ratepayers to properly reflect the benefits and burdens of the expense (Order 09-020 at 19-20).

62 In UE 197, the Commission adopted Staff's principal that costs for meals and entertainment are discretionary and should be shared equally by ratepayers and shareholders (Order 09-020 at 20-21).

63 In UE 197, the Commission adopted Staff's principal that these costs are discretionary and should be shared equally by ratepayers and shareholders (Order 09-020 at 20-21).

64 The Commission's policy is to disallow 75 percent of performance-based bonuses (because they are generally focused on increased earnings and, therefore, bring more benefit to shareholders) and disallow 50 percent of merit-based bonuses (because they equally benefit shareholders and ratepayers). Union bonuses are treated in the same manner as non-union bonuses. (Order 99-697 at 44-45; Order 99-033 at 62.)

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Dyck/30

Q. Summarize Staff adjustments for expense recorded in FERC accounts 921, 922, 930 and 931 as a result of using different escalation figures.

A. This adjustment of ($652,794) in Table 6 was determined by using the sum of the departmental and corporate values for nonpayroll for each of the FERC categories below.[65] This escalation adjustment was made independent of any cost sharing recommended in Table 5 or removals recommended in other testimonies. Therefore, the total recommended adjustment Staff is making in this issue is a combination of the two values, which is ($865,046). In the event there is some other adjustments to expenses in these accounts, the escalation adjustments listed below would also need be updated because there would be new values from which to start the escalation. However, in the Company's O&M model workpaper, their escalation figures are embedded in their Test Year request values in the Dept. Non-Payroll forecast tab, that is why it is difficult to make the cumulative calculations that would be needed to show what updated escalations would be if the requested values had been different or had included the specific adjustments by FERC Account.

[65] See Exh 1400 – OM Model Workpaper, tab O&M TY FERC Allocation Summary and SDR 58 Attachment 2 Non-Labor O&M.

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Dyck/31

TABLE 6: NON-LABOR ADJUSTMENTS USING UPDATED ESCALATION VALUES

Administrative and General Expense (Non-Labor) FERC Accounts	TY (Company) System	TY (Company) OR	TY (Staff) System	TY (Staff) OR	Adjustments System	Adjustments OR
921: Office Supplies and Expense	$55,691,773	$49,080,025	$54,911,081	$48,392,017	$780,692	**$688,008**
922: Administrative Expenses Transferred - Credit	-$25,374,489	-$22,403,377	-$25,213,617	-$22,261,342	-$160,871	**-$142,035**
930: Miscellaneous General Expense	$5,414,275	$4,977,707	$5,341,904	$4,912,455	$72,371	**$65,252**
931: Rents	$11,024,949	$9,742,139	$10,977,906	$9,700,570	$47,042	**$41,569**
Totals	$46,756,507	$41,396,494	$46,017,273	$40,743,700	$739,234	**$652,794**

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 490
WITNESS: JULIE DYCK

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1001

Witness Qualifications Statement

APRIL 18, 2024

Docket No. UG 490

Staff/1001
Dyck/1

WITNESS QUALIFICATIONS STATEMENT

NAME: Julie Dyck

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Utility Analyst
Rates, Safety and Utility Performance Program

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION: I have a Bachelor of Science from Berea College in Political Science. I also hold a Masters of Integral Economic Development Policy specializing in the public sector and econometrics. I have completed rate school with NARUC, a data analytics course with Google, and am currently a NABE Frank Schott Scholar working towards becoming a Certified Business Economist.

EXPERIENCE: I was employed as a Junior Utility Analyst by the Oregon Public Utility Commission starting in June 2021 in the Telecommunications and Water division. I transitioned to the ERFA/RSUP Division in July of 2022 as a senior economist. Within this division, I currently perform a range of financial analysis duties related to natural gas and electric utilities, with a focus on Power Cost filings. In addition, I assist with Purchased Gas Adjustments, Annual Power Cost filings, and General Rate Cases. Rate case experience include: UG 435, UE 399, UE 416, and UG 461. I was previously employed as an adjunct professor of Econometrics at the Catholic University of America and as an Analyst in the Office of Management and Budget (OMB) within the Executive Office of the President (EOP), where I worked as part of a team on higher education funding. Prior to EOP, I was an Economic Consultant for the U.S. Conference of Catholic Bishops.

CASE: UG 490
WITNESS: JULIE DYCK

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1002

Exhibits in Support
Of Opening Testimony

April 18, 2024

- Disclosure: Risks scored in red must be disclosed on status reports, including mitigation strategy.
- PM Role: The PM is responsible for communicating and escalating issues and ensuring that all impacted parties understand the possible negative consequences. They are accountable for ensuring the risk reaches the appropriate level of response, but are not always accountable for the mitigation itself.
- SteerCo and Sponsor Role: For red exposure risks the Sponsors and/or Steering Committee are responsible for making critical risk decisions (e.g. approving how are we going to tackle this risk) and accountable for ensuring the mitigation strategy is implemented (e.g. working to identify new resources to support a capacity risk).

Yellow Risk Exposure

- Mitigation Strategy: Yellow exposure risks should likely have a mitigation strategy, although in some cases accepting the risk may be acceptable. If this is the case, all impacted parties, including sponsors and steerco need to be aware and sign off on the impact.
- Disclosure: Risks scored in yellow must be actively discussed and managed in the project leadership team meetings.
- PM Role: The PM is responsible for communicating and escalating risks to the appropriate members in project team; they are accountable for ensuring the risk reaches the appropriate level of response, but are not always accountable for the mitigation itself.
- Sponsor Role: The Sponsor is responsible for acknowledging risk mitigations, and removing barriers for the risk owner to tackle the mitigation.

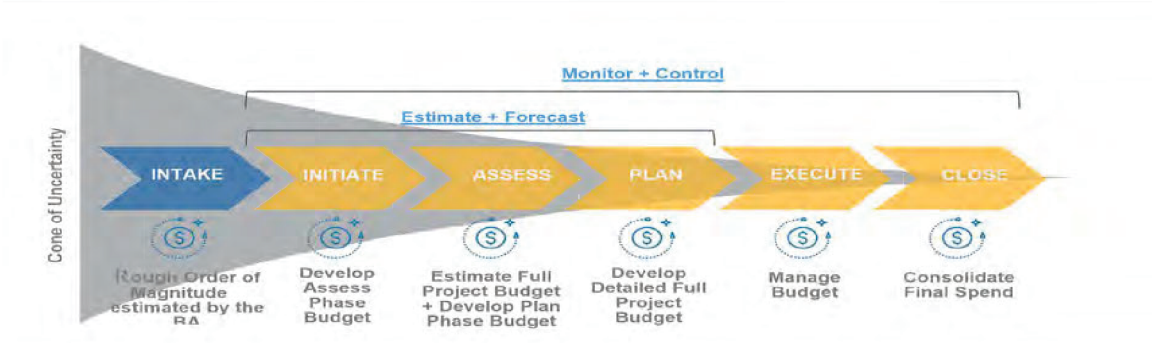
Green Risk Exposure

- Mitigation Strategy: Green exposure risks need to be monitored, but do not necessarily need an active mitigation strategy
- Disclosure: Green risks should be part of the risk register but do not need to be escalated.
- PM Role: The PM is responsible for monitoring the risk and ensuring it does not increase in probability or impact.

As risks occur, the PM moves them into the Planview issues list, which is also monitored to ensure all stakeholders understand the consequences.

Accounting and Budgeting Practices

Project managers are responsible and accountable for maintaining a project's budget – from the estimates generated during the Initiation phase through finalization of the project's actual spends at Project close. The diagram below outlines the high-level Budgeting activities that take place throughout the project's life cycle:



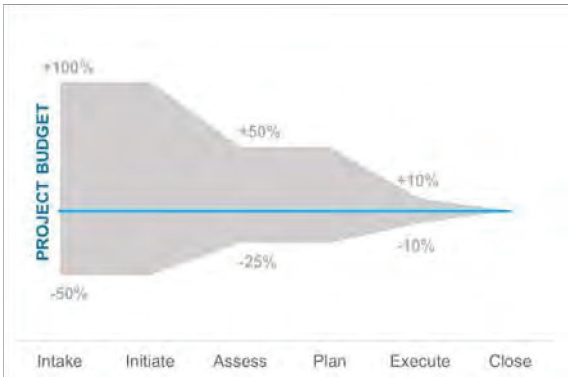
In order to effectively manage budgets, PMs are responsible for tracking and managing internal and external spend and submitting change orders as needed to keep the budget balanced and accurate. Our PMO Cost Accountant closely monitors spending on a month-to-month basis to ensure we're providing enough transparency as a public utility.

Forecasting / Estimation

Project Managers will begin their forecasting at Initiation. At this phase of the project, Project Managers should work closely with stakeholders and Accounting to begin outlining high level project costs; these estimates should become more refined as the project progresses.

Cone of Uncertainty

As you develop your budget, the cone of uncertainty provides the acceptable amount of variance at each stage. Communicate thoughtfully to key stakeholders about the cone of uncertainty. Explain that at this phase in a project, the budget is an estimate with a wide potential variance. This will become more defined as the project unfolds. For a typical project, the variance at each phase is usually:



- Intake: When a project is first proposed at Intake, there is a Rough Order of Magnitude (ROM) estimate provided. Given that this estimate is provided before any stakeholders have been engaged or SOWs generated, it is an extremely high-level estimate. At this stage the rough order of magnitude is entered into the Triage form where we expect the variance to fall anywhere from -50% to +100% of the eventual project budget; for those projects that do not have much precedent, variance may be even larger.
- Initiate: As the project enters the "Initiate" phase, you will develop a budget for the Assess phase however you will NOT be required to formally estimate total project costs at this juncture.
- Alternatives Analysis: At the end of the Assess phase when you submit the AA, the project should have the first solid estimate of full project cost. At this point, some variability is still expected: -25% to +50%
- Plan: Finally, as you work through the Planning stages you will be further refining your project forecasts. You should be receiving completed RFPs from prospective vendors. These, along with other refined estimates, will allow you to submit your full project budget, which will constitute your project baseline as you enter Execution. This estimate is expected to fall within +-10% of your actual spends.

Capital vs. O&M

As you begin to estimate project costs, you should speak with Accounting about setting up your project costs. Project Costs are split between Capital and O&M, and both should be included in your budget for all elements (internal labor, external labor, materials, etc.). The capital asset policy outlines what is considered capital vs O&M, but here is a general guideline:

- Interest on mortgages accrued at date of purchase
- Accrued and unpaid taxes at date of purchase
- Other costs incurred in acquiring the land
- Water wells (includes initial cost for drilling, the pump and its casing)
- Right-of-way and easements

CWIP – Construction Work in Progress

Construction Work in Progress consists of construction costs incurred until a capital construction project is put into service; only directly related costs, AFUDC, and Construction Overheard (COH) can be capitalized. Generally, internally developed computer software projects are considered construction projects. Please consult the Accounting Manager if you believe you have a capital internally developed software project to further understand the types of costs that may be capitalized; the accounting guidance related to internally developed software is specific and technical and should not be interpreted without the Accounting Manager's involvement. CWIP project costs are included in FERC account 107 and can include the following

- Direct costs
- Construction Overhead (COH)
- Allowance for Funds Used During Construction (AFUDC)

Completed construction not classified (CCNC) amounts are included in FERC account 106. This account is used to classify capital costs that have not been transferred from work orders to plant retirement units. The transfer from CWIP to CCNC places the asset in service, stops AFUDC, and begins the charging of depreciation expense based on the FERC plant account.

Information Technology Project Capitalization

Information Technology Projects are generally a mix of both O&M Expense and Capital, depending on the nature of the work performed and the time during the Project's lifecycle when the work is performed. At the beginning of an Information Technology Project, the identification and documentation of system requirements, the evaluation and analysis of alternative systems, and the selection analysis is charged to O&M expense. Project management during the system evaluation and selection phase is also charged to O&M expense.

After the software selection has been made, future Project costs are capitalized. Specifically, costs associated with project management, documentation of the "As-is" and the "To-Be" processes, conversion and loading of historical data, and the configuration of the new software is capitalized. The "As-Is" processes are those being followed with either manual or existing software. The "To-Be" processes are those that will be followed in the future using the new software. Further, the cost of "first-year maintenance" paid as part of the software purchase is capitalized and additional costs related to changes in system design and/or system selection during the implementation effort and the development of process manuals and documentation is also capitalized.

Requirements gathering, design and implementation of enhancements to existing systems, and system upgrades may be capitalized if they add significant new functionality to the system; please work with the accounting department to make this determination.

After "Go-Live" follow-on costs relating directly to the project are capitalized. For example, bug fixes and minor enhancements would be capitalized up to the point in time when the system is stable and working as designed. At the end of the Information Technology Project's life cycle, many costs are charged to O&M expense. For example, training for users and training for information technology staff is charged to O&M expenses. Ancillary training expenses, typically meals, travel, and lodging, are also charged to O&M. Costs associated with shelved/abandoned improvements, sunk costs as a result of system reevaluation and re-selection, legal and other administrative costs associated with a contract dispute with a software/system vendor, etc. are charged to O&M expense.

Report development capitalization should be discussed on case by case basis with the assumption that the development of most reports will be classified as O&M expense. Exceptions may include reports being developed as part of a new system implementation project or reports requiring significant data model/structure development for an existing system. Examples of these reports include the following:

- Building new SAP Business Warehouse "cubes" or "extractors" to enable the creation of new reports.
- Reports associated with a Capital Project (e.g., Project Systems reports) regardless of whether they are on an existing system.

System Integrity Costs

Typically, our general rate cases will allow for a system integrity program, allowing the Company to track into rates in the following year the costs of maintaining our distribution and transmission system. Typically, these programs will require the Company to expense of a portion of the costs, for example the current program requires the Company to expense the first $4,500,000 and any balance over this amount is reclassified to Plant Capital Accounts and tracked into rates in the following year through the Purchased Gas Adjustment.

Fleet Charges

Generally, fleet costs are allocated via overhead rate to their respective work orders based on employee work hours. Work orders determine how these charges are allocated to O&M and capital. New vehicle costs, plus the cost to ready it for service are capitalized.

Minor Item Service and Damage Repair Capitalization Considerations

Line repairs requiring 10 feet of pipe or more are capitalized. Repairs are generally expensed but total replacements of retirement units are capitalized. Grading and sewer work on Company land is generally considered capital construction costs. See Table 1 below for specific treatments.

Table 1. Service and Repair Considerations

Work Category	Expense	Capitalize
Service Line Repair / Replacement	Replacement of less than 10 feet or repair to current service line.	Replacement of 10 feet or more of service line
Main line Repair / Replacement	Replacement of less than 10 feet or repair to current main line	Replacement of 10 feet or more of main

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 156
Was cloud-based software addressed in UG 435 or any of the other prior general rate cases (GRCs)?

a. If so, identify which GRCs this issue was addressed in.
b. Are the terms cloud-based software and IT&S investments used interchangeably?
c. Explain how cloud-based solutions are different than their alternatives.
d. Please distinguish projects that are cloud-based and those that are not.
e. Is it typical to have this many IT&S projects up for recovery in a GRC?

Response:

Yes, cloud-based software was addressed in UG 435 and UG 388.

a. UG 435 OPUC DR 482 NWN Response, part b (attached as UG 490 OPUC DR 156 Attachment 1). UG 388, NWN/600, Downing/11-14, 16-27, 39, 50; NWN/1600, Downing/22.
b. No, the terms cloud-based software and IT&S investments are not interchangeable. Cloud-based software falls under the umbrella of IT&S investments. But investments that are not in the cloud are included as well.
c. Please refer to NWN/700, Downing/8-11 for a detailed discussion of the differences between the two basic IT&S hosting options: cloud-based and onpremises. Importantly, many software vendors are transitioning their offerings to be solely cloud-based, meaning that certain products are no longer available as on-premises solutions. For instance, SAP SuccessFactors, which is used for human resources management, is available only via the cloud, while other software vendors such as Genesys have announced terminating support deadlines for on-premises solutions.

   Where both cloud-based and on-premises solutions are available, the two options differ in several ways:

   1. Infrastructure Ownership and Management: With on-premises solutions, businesses own and manage all the necessary hardware, networking equipment, and software licenses themselves. In contrast, cloud-based solutions are hosted and managed by third-party providers. This means

businesses do not need to purchase and maintain physical hardware necessary to host the software service, or expend the same level of resources to develop and implement software updates and patches.

2. Scalability and Flexibility: Cloud-based solutions offer much greater scalability and flexibility compared to on-premises alternatives. Businesses can easily scale their resources up or down based on demand without having to invest in additional hardware. This elasticity ensures that resources are allocated efficiently.

3. Cost Structure: Cloud-based solutions often operate on a subscriptionbased pricing model, where businesses pay only for the resources they use on a monthly or yearly basis, which is creates an incremental O&M increase and generally escalates through time. The implementation of these programs can be capitalized but the depreciation schedule is approximately 5 years, which often causes lag in recovery for a significant portion of the investment. On-premises solutions, on the other hand, require significant upfront capital expenditure but the depreciation schedule is approximately 15 years.

4. Reliability and Security: Cloud providers invest heavily in infrastructure redundancy, security measures, and disaster recovery protocols, often providing higher levels of reliability and security than what can be achieved with on-premises solutions. However, businesses must still carefully evaluate and choose reputable cloud providers and implement best practices to ensure data security and compliance.

5. Maintenance and Updates: Cloud-based solutions typically handle maintenance tasks such as software updates, security patches, and hardware upgrades automatically, reducing the burden on IT staff. Onpremises solutions require businesses to manually manage these tasks, which can be time-consuming and costly.

d. For all cloud based investments, please see submitted workpaper "UG 490 – Exh. 1714 -WP1 – Cloud Based Assets – CONFIDENTIAL".

e. We interpret this question as asking whether the number of IT&S projects included for cost recovery in this rate case is typical of the current state of the industry. Based on that understanding: yes. IT&S modernization is occurring industry-wide as companies are:

a. Required to update or replace non-supported systems.
b. Forced to transition to cloud solutions as vendors have no other options.
c. Managing risk and regulatory requirements by mitigating cybersecurity threats.

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 482

482. In reference to NW Natural/600, Downing/page 30, Table 1 at line 6:
a. Please clarify that the total Oregon allocated dollar amount for Horizon capital costs of $63.7 million excludes the other IT projects noted in NW Natural/600, Downing/page 2, lines 5-11.
b. If the Horizon Program is primarily a cloud based solution, please provide a detailed response explaining how significant capital costs associated with this project are prudent.
c. Regarding the $8.8 million in "contingency and other costs", have any of the contingent funds been used or are projected to be used? If yes, please provide:
- i. A breakout for each specific project cost overrun necessitating the use of contingency funds.
- ii. A detailed explanation describing why each cost overrun occurred.
- iii. A detailed description of the steps the Company took to manage project costs and adhere to the Company approved project budget.
- iv. If the contingency funds are not needed to complete the project, how will the Company remove these costs from this rate case?

Response:

a. The total Oregon allocated dollar amount for Horizon capital costs of $63.7 million excludes the other IT projects noted in NW Natural/600, Downing/page 2, lines 5-11.

b. The Financial Accounting Standards Board (FASB) issued Accounting Standards Update 2018-15 (ASU 2018-15) specifically to address accounting for cloud-computing software. This update requires companies to capitalize certain costs associated with implementing a cloud arrangement. These costs include implementation to get the hosted service set up, configured, and ready for use. Additionally, new software licenses qualify for capitalization as they fall in the category of Bring Your Own License (BYOL). This means we own the licenses and could pull them from the cloud and install locally if we chose to in the future.

The implementation for cloud or on-premise solutions of these applications will still require design, configuration, development, testing and deployment activities to be successful.

c. Contingent funds have been used and are projected to be used.

i. Please see UG 435 OPUC DR 482 attachment 1, column E – Amount of Change. Total approved contingency use through March 31, 2022, is $4,519,671, Column E Row 23.
Total projected contingency use through March 31, 2022 is $975,000, Column E Row 29. Analysis is still underway for scope and work effort; these are estimates provided by our service integrator.
The Horizon Program is still in process and additional items requiring the use of contingency funds may be required. At this point, the project anticipates a need to use the remainder of the contingency funds by October 31, 2022, but are not currently projected or known. ii. Please see UG 435 OPUC DR 482 attachment 1, column G – Reason for Change.
For the change orders over $1 million dollars, we have attached the change order requests that provide additional details around the explanation of cost overrun.
IQGEO change order for $2 million, see UG 435 OPUC DR 482 attachment 2.
Reporting change order for $1.5 million, see UG 435 OPUC DR 482 attachment 3.
For the projected change orders, analysis is still underway for scope and work effort; these are estimates provided by our service integrator and will follow our change control process for approval.

iii. The Horizon Program is a multi-tier structured and adhered-to governance model with key leadership providing direction and oversight. Please see attachment UG 435 OPUC DR 482 attachment 4.

The Horizon Program has an established Change Control Process that aligns to the governance model. Please see attachment UG 435 OPUC DR 482 attachment 5.
Below is the Horizon Program meeting cadence directly related to project costs:

1. Weekly review of project costs with NWN program Finance and Accounting

2. Weekly review of contractual obligations and service level credits with NWN program team and NWN legal team

3. Weekly review of change control board

4. Monthly Service Level Agreement metrics review with program team and Accenture

5. Monthly invoice review with Accenture and program Finance and Accounting

6. Monthly review of project costs with program Finance, Accounting, Rates and Regulatory, and Program Executives

7. Quarterly review of projects costs with the Senior Executives and IT&S Alignment Team

Following the Horizon Program governance model, change control process, and meeting cadence describes the process that the Horizon Program follows to manage project costs and adhere to the Company approved project budget.

iv. If contingency funds are not needed to complete the project, the Company is willing to adjust the capital in its compliance filing to the actual amount spent for Horizon, when the project goes into service.

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Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 416

Have you estimated the net benefits of any of the capital projects?
If yes, please describe. Explain the rationale for including cloud-based assets in rate base.

Response:

All Information Technology & Services (IT&S) capital projects are expected to have net benefits, as compared to not undertaking the project or undertaking a project alternative analyzed by the Company. These benefits can manifest in various ways, including but not limited to the maintenance of safe and efficient operations, improved customer experience, data protection and privacy, business continuity, network integrity, risk mitigation and enhanced functionality. The benefits and costs of each capital project is set forth in testimony, NW Natural/700. For instance, at NW Natural/700, Downing/4344, the Company explained that the Telemetry Refresh Projects support the Company's prompt and accurate control of the gas distribution system; by undertaking the upgrades and replacing outdated technologies, the Company can not only ensure the safe and reliable provision of service, but avoid the need to maintain a lease at the Company's former headquarters location.
The Accounting rules determine the capitalization treatment of Cloud Computing Arrangements if the criteria are met for capitalization. FERC (Regulatory) and GAAP do not differ on the types of costs that can be capitalized or expensed related to Cloud Computing Arrangements. As it relates to Cloud Computing Arrangements (CCA) that are Service Costs, FERC made a final ruling on ASU 2018-15: Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract to all jurisdictional public utilities and licenses, natural gas companies and centralized service companies. For regulatory accounting, capitalized implementation costs should be recorded as utility plant assets in Account 303 (Intangible Plant - Computer Software) and should be amortized over the term of the associated cloud computing arrangement in Account 403 (Depreciation Expense).

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Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 206

Please provide a narrative description of NWN's capital budgeting process including but not limited to development responsibilities, load study process, annual timing, and approval process.

Response:

The capital forecast is updated multiple times throughout the year. This forecast incorporates the most recent information based on requirements to maintain a safe and reliable system. Each year's budget is based on the forecast created in December, which is presented to and approved by the Board of Directors.

Finance facilitates the process with the five individual business units that provide those forecasts: Engineering, Customer Acquisition, Information Technologies, Facilities, and Transportation & Meter Shop. Review meetings take place with the managers, directors, and officers where the assumptions and forecast are reviewed and determined. Once approved, each group sends their forecast to Finance for inclusion in our overall forecast. The overall forecast is used to inform various groups on progress, adjust our planned spend and include impact the current and long-range forecast. Finance also facilitates a monthly review of current year variances against the approved budget.

Each business unit uses a bottom-up approach, where they determine required and run rate work in addition to identifying other projects that are needed. Detail is provided for applicants and projects.

Facilities:

Potential projects are identified by the business and/or Facilities department for consideration. The facilities projects steering committee reviews all requests, validates the potential need for the projects and determines if the projects should be added to the facilities 5-year roadmap for further evaluation.
Forecasts for each project are updated quarterly and reviewed by the Facilities Steering Committee, Finance team, and officers.

Transportation and Meters:

Vehicle replacements are evaluated based on a combination of vehicle vintage and mileage. Each year the list of vehicles that meet either the age or mileage limits are evaluated. That list along with department feedback creates the replacement list for the following year. Equipment and Trailers are determined to be replaced based on business need and, on a case-by-case basis. Tools are also requested by departments and are evaluated for business need and included on a list for purchasing the following year. Meter needs are developed based on current meter inventory, customer growth forecasts, meter change outs, PCC changes as well as factoring in vendor lead times.

Customer Acquisition:

Services and Mains capital spend is forecasted based our customer growth forecast or footage of mains multiplied by estimated cost. Housing start projections from the Oregon Department of Economic Analysis are a key assumption when developing new customer projections. Permits are based on previous year actuals plus inflation. Meter installations are based on estimate number of units times cost per unit.

Engineering:

Planned projects are based on need, resource, and supply chain availability. A significant amount of work is driven by jurisdiction and compliance requirements. Planned capital work is typically identified in advance based on long range plans, Facility assessment reports, Equipment studies, safety plans or DIMP & TIMP plans. Prioritization is given to projects based on urgency or feedback from operations personnel. Nearer term planned work can be due to equipment unexpectedly failing or showing near end of life, avoidance of potential pipeline safety impact due to natural forces, and jurisdictional franchise obligations. Larger, discrete projects are individually assigned projects in our project management office and have capital spend budgets and expected in-service dates that are managed through the duration of the project. Those are all individually tracked through our forecasting process. Forecasts for some categories of work are based on historical spend trends.

IT&S:

The collection of projects reflects various business needs. Enterprise Applications projects are driven by new or changes to existing systems to support new or changed compliance requirements, or to support new business needs. Information Security projects follow the cybersecurity strategic plan. The Enterprise Architecture forecast follows the IT&S 5-year strategic plan and are typically new capabilities driven by business needs focusing on building resilient modern platforms, optimizing value of existing platforms and building new

A project's Team site is capabilities as required. Network, Infrastructure and Service delivery typically entail technical refresh cycles. Finally Operational Technology represent engineering projects that require IT&S execution, so this forecast follows the needs and projections of some of the engineering's forecasted capital plan.

The business units where applicable coordinate with the Portfolio Management Committee which meets to discuss, review, prioritize and approve funding for projects and determine if it should be added to the portfolio. Considerations included for discussion are urgency, capital spend and resource constraints. The business units triangulate with the portfolio management committee to ensure that projects are approved and being included in the budget/forecasting process. Following approval, projects are included into the forecast cycle.

Microsoft Teams

Overview: intended for the internal (contractor and FTE) project team to collaborate, discuss and conduct core project activities. Individual workstreams use themed channels chat and document sharing without breaking the thread of discussion. The tool provides continuity of knowledge for project team members joining mid-project and ensures remote access to documents and chat via the Teams Mobile app.

Requesting a Site: When a project is initiated, the PM should request at Team collaboration site by visiting the request form. Instructions on how to complete this form can be found here (use the directions attached to project sites). This will instigate the creation of both a SharePoint site for the project, and an associated Team site configured based on the project's discipline for the PM to adjust to the needs of the team.

Channels and Access: By default, your project Team will be private (invite only). It is the Project manager's responsibility to manage access to the Team and individual channels making sure that the right people have access to each section of the Team. Remember that each channel has its own document storage, and those with access to that channel will be the only ones able to see that documentation. This likely means a contract or procurement channel that is available only to the PM and legal (as needed), and then workstream channels that are available to everyone in the project team for visibility (e.g. Change Management, Project Management, Testing, etc.). Recommended channels will already be set up for the PM to work with but can be adapted to the project need.

Tabs: We recommend that the project manager configure the Tabs (header links) in the Team's channels to provide easy navigation to project resources. The recommended tabs are below, with the associated app to use to add that link (Hint: click on the + symbol at the top of the channel to add new Tabs).

IT	Engineering	Facilities
• Posts (default) • **Project's SharePoint Site** (use SharePoint app) • Files (default) • Planview Site (use website app) • Azure DevOps (use Azure app) • PowerBI (use website ap) • PM Handbook (use website app) • CM Handbook (use website app) • BA COE (use website app) • ITSM (use website app) (coming soon) Project Place	• Posts (default) • SharePoint Site (use SharePoint app) • Files (default) • Planview Site (use website app) • PowerBI (use website ap) • Engineering Site (use website app) • IQGEO (use website app) • R-Drive (use website app) PM Handbook (use website app)	• Posts (default) • SharePoint Site (use SharePoint app) • Files (default) • Planview Site (use website app) • Smartsheet Schedule (use website app) • PowerBI (use website app) • PM Handbook and/or trainings (use website app)

Training and Resources: A high level overview of how to leverage Teams as a project is available here, and additional tutorials on how to use Teams are available on the M365 initiative page.

Planview

Overview: Planview is NW Natural's Project Portfolio Management (PPM) tool, our home-base for the project process - from idea to closure. Projects are required to leverage Planview for stage gates, status reporting, schedules, resource management and budgeting, as it serves as the source of truth for much of NWN's rates reporting. You can access Planview on your web browser when you're within the NW Natural network and have been granted access to the tool.

Resources: This handbook references Planview for how the tool should be used through each phase (see initial checklists). In addition, guides on how to use the tool can be found on the Hub. We recommend Project Managers watch the full training series listed at the bottom of the PM column as they get started leveraging Planview.

* indicates that the document must be complete and accepted in order to move to the next phase

blue indicates that the document is formally attached or described to the stage gate request

Project Lifecycle at a Glance

Goal	INTAKE Understand the root problem and opportunity to inform the selection of the right projects at the right time	INITIATE Align and approve on business case, and the resources needed to assess the project	ASSESS Develop requirements, assess options, determine alternatives and preferred solution	PLAN Fully flesh out the selected solution and define the execution path to achieve the project goals	EXECUTE Track, monitor and control the project as work is completed	CLOSE Operationalize, adopt and hand over the project deliverables
Project Management (Budget, Schedule, Scope, Resourcing + Project Governance)	*Sponsor: Intake form *PMC: Project review and selection	***PM: Assess Phase Budget** ***PM: Initial Project Charter** ***PM: Decision Log, Risk Log, Issues Log** ***PM: Assess Phase Resource Plan** ***PM: Monthly Status Reports** ***PM: Org Chart** *PM: **RACI** and **RAPID** PM: Teams and SharePoint Site PM: Stakeholder Register PM: Steering Committee + CCB **Sponsor**: Project oversight + governance *PM: Submit "Move to Assess" Gate	PM: Assess the cost of possible solutions ***PM: Design/Plan Phase Budget** ***PM: Design/Plan Phase Resource Plan** *PM: Design/Plan Phase Schedule ***PM :Final Project Charter** ***PM: Decision Log, Risk Log, Issues Log** ***PM: Monthly Status Reports** **Sponsor**: Project oversight + governance ***PM/Sponsor**: Alternatives Analysis (if over $1MM w/ COH) *PM: Submit "Move to Plan" Stage Gate	PM: Confirm the costs of the selected solution, forecast costs to plan the project ***PM: Execution Budget and forecast** *PM: Project Execution Approach / Plan ***PM: Execution Phase Resource Plan** *PM: Execution Phase Schedule ***PM: Monthly Status Reports** **PM/BA/Tech Lead/Sponsor:** Determine final project scope ***PM: Decision Log, Risk Log, Issues Log** **Sponsor**: Project oversight + governance **PM/Sponsor**: Transition to Operations Plan (IT only) *PM: Submit "Move to Execute" Stage Gate	**PM**: Weekly Status Reports PM: Monitor and control costs, compare to actuals PM: Monitor and control scope delivery, resource capacity, schedule and all other project aspects to ensure project is on track ***PM: Decision Log, Risk Log, Issues Log** **Sponsor**: Project oversight + governance PM: Go/No Go Criteria ***Sponsor**: Go/No Go Approval PM: Move project to "Prepare for Closure"	**Sponsor**: Project oversight + governance *PM: Lessons Learned *PM: TECO *PM: Project close activities **PM/Sponsor**: Final Transition to Operations Plan (IT only) *PM: Final budget true-up **PM**: Submit "Move to Close" Stage Gate
Business Requirements / Design	**BA**: Triage **BA**: Context Diagram (as applicable)	**BA**: Initiation Context Document (BOSCARD) **BA**: Context Diagram **BA**: Business Analysis Work Plan	**BA**: Elicitation + Results ***BA**: Business Case ***BA**: Current State Documentation **BA**: Gap Analysis **BA**: Requirements + Documentation **Biz Owner**: SOW summary for RFx	**BA**: To-be process map and documents ***BA**: Requirements Documentation **BA**: Gap Analysis ***BA**: Functional Specs	**BA/QA**: User Acceptance Plan **BA/QA**: Functional Test Plan **BA/QA**: UAT Results and Approval ***BA**: Updated Requirements Documentation ***BA**: Knowledge Base Articles ***BA/QA:** Requirements Traceability Matrix	**BA**: Completed Requirements Traceability Reports **BA/CM**: User Surveys + Interviews
Change Management (if a CM is assigned to the project)	***CM/BA:** Stakeholder Register	***CM**: Case for Change ***CM**: Change Artifact List **CM**: Rough Change Assessment	***CM**: Change Impact Assessment ***CM**: Stakeholder Analysis ***CM**: Change Strategy **CM**: Change KPI Development	***CM**: Training Needs Assessment, Plan + Materials ***CM**: Comms Plan + Materials **CM**: Engagement Plan + Materials **CM**: Change Portfolio Assessment Form	***CM**: Training Materials (including FAQs, QRGs) **CM**: Training, Communications + Engagement Delivery + Support ***CM/Application Owner**: Change Artifacts / Operations Handover, Knowledge Transfer Plan **CM**: Change Readiness Assessment	**CM**: Training, Communications + Engagement Delivery + Support **CM**: Adoption Tracking **CM**: Change Close Survey **CM**: Knowledge and Tools Transfer, Lessons Learned
Technical Development	**EArch**: Confirmation that IT&S Alignment Committee Review is complete	**Tech Lead:** Technical resource plan	**EArch**: Solution Context Diagram **EArch**: Solution Options + Design **EArch**: ARB and TRB are initiated ***EArch**: Provides RFP scoring criteria against architecture and requirements and/or assessment of alternatives and recommendation of selected option **EApps:** Software Development Estimate **Tech Lead:** Technical requirements **IT Security:** Assess security needs	***EArch:** ARB and TRB Approval **EArch**: IT&S Ticket Request ***EArch:** Solution Architecture Summary **EArch:** Data Model and Migration Plan **Application Owner:** Technical Specs **Tech Lead:** Source Target Mapping **Tech Lead:** Business Impact Assessment ***Tech Lead**: Final Design and Tech Specs **Tech Lead:** SOX Compliance Plan **Tech Lead**: ETL/Integration Plan **IT SecOps**: Vendor Risk Assessment ***IT SecOps:** Security Design and Review **IT SecOps**: Incident Response Plan **IT SecOps:** PCI Assessment Questionnaire of Attestation of Compliance **IT SecOps:** Security Plan of Action and Milestones **Solution Architect:** Infrastructure Implementation Plan **Solution Architect:** Infrastructure Specifications	**EApps:** Software and Configuration Source Code **EApps:** Software Build **EApps**: Deployment **EApps:** Rollback Scripts **EApps:** Software Runtime Artifacts **EApps:** Release Notes ***EApps**: Run Book **Tech Lead**: Solution Cutover Plan **Tech Lead:** Data Conversation / Migration Plan **Tech Lead:** Solution Test Plan, Scripts, Results, Defect List **Tech Lead**: Production Release Verification Plan and Results **Tech Lead**: Information Transfer Agreement **Tech Lead:** Vendor Security Assessment **IT SecOps:** Security Testing / Vulnerability Scans, Remediation Plan **Disaster Recovery, Tech Lead**: Disaster Recovery Testing and Plan **Business Continuity**: Business Continuity Plan **Tech Lead**: Change Control Review Board Release Approval **IT:** Technical Support Plan	**IT Security**: Security Plan of Action and Milestones
Engineering Requirements and Design	**Eng**: Triage	**Eng/PM:** Survey and Assessment Plan	**PM:** Survey, Assessments **Risk + Land:** Easements ***Eng:** Initial (10-30%) Designs ***Eng:** Permitting Assessment and Plan ***Environmental:** Enviro Assessment **PM:** Geotech **PM/Sponsors:** Resourcing Plan	**Eng:** Specifications (if externally resourced) ***Eng:** Traffic Control Plan **Eng:** Potholing ***Eng**: 90% Design **PM:** Geotech **Permitting Specialist:** Permits **Purchasing/Stores**: Stock and Non Stock Material Requirements, Material Reservations, Bids including Q&A, Quotes, RFQs **RMC**: Field Resource Schedules **Construction**: Resourcing	***PM:** Operations + Maintenance Plan, Engineering Procedures **PM/Eng:** Construction Management **Tech Training:** Field Training	**PM:** O&M Manuals ***Eng:** As-Builts, Management of Change, CDM, Testing and Verification Documentation
Vendor Selection + Procurement	**Procurement:** Resource planning	**Procurement**: Procurement strategy / sourcing research + list **IT Compliance**: TISA for new vendors **Procurement**: Purchasing Process if a vendor is needed for assessment: **Procurement**: RFP and vendor selection for any assess-vendors **Corp Security:** Background checks	**Procurement:** RFx development, process and responses; sync with Legal **Project Manager**: Competitive Assessment Memo (CAM) if no RFx **Procurement:** Scorecard **Procurement / Sponsor:** Vendor selection **IT Compliance:** TISA to shortlisted RFx finalists	***Procurement:** SOW **Procurement**: PO Management (for change orders, etc.) **Legal/Procurement:** Contracting and Negotiation **PM:** Onboarding **PM**: ITP checklist (for IT projects)	**Procurement**: PO Management (for change orders, etc.)	

Risk Identification: Risks are derived from various sources, some of which can be identified before a project starts, and some of which are surprises along the way. Many of these risks or sources are common across projects so the PM may start with NWN's common risks by project type. These tools can be leveraged as a starting place, but it is the job of the PM to coalesce common and unique risks that the project faces.

Risk identification should be conducted on an ongoing basis, but two points of the project are particularly important:

- During the Assess phase, leverage the assessment team to identify underlying risks with the chosen solution
- During the Planning phase, focus on what challenges might come up during execution; best practice is to hold a workshop with your project team to work through identification, evaluation and response plan

Risk Evaluation: As we document risk, we talk about its probability and its impact; this allows the project team to make thoughtful decisions about potential risks. To make this simple, we can use the following definitions to give a score for both probability and impact:

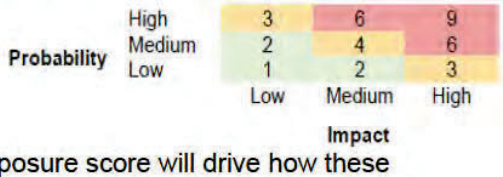
Probability of Risk Occurring

Level	Probability	Score
High	The risk is likely or certain to occur. Specifically, there is more than 75% chance that the risk occurs	3
Medium	There is some likelihood that the risk will occur. Specifically, there is between a 25% and 75% chance that the risk occurs	2
Low	It is not very likely that the risk will occur. Specifically, there is less than 25% chance that the risk occurs	1

Impact If the Risk Occurs

Level		Cost	Schedule	Scope	Quality	Score
High	If the risk occurs, it will have a severe impact on the ability to achieve the project's critical objectives	Cost increases would be beyond the total authorized spend, causing a change order	Key project event or milestone will be delayed by more than 3 months	Scope decrease would have significant impacts on key deliverables	Performance is degraded to the point that the project would not meet its objectives	3
Medium	If the risk occurs, it will somewhat impact the desired results either crippling a secondary objective or causing a critical outcome to be degraded	Cost increases would dip into contingency funds	Key milestone will be delayed	Scope decrease would impact some core objectives or key deliverables	Performance would be below goal and may have some impacts on project objectives that can be mitigated with work arounds	2
Low	If the risk occurs it will have little or no impact on the project's ability to achieve its objectives	Cost increases could be managed within the approved budget	No key milestones will be impacted	Scope decrease would not impact core objectives or key deliverables	Requires minor performance trades, but will not significantly inhibit project objectives	1

These numbers should then be evaluated to determine overall exposure, which will drive the project team's mitigation response:



Risk Response and Control

Risk response is perhaps the most important step in risk management; it is important to focus efforts and communications on the most important risks, with targeted and thoughtful mitigation strategies. The risk exposure score will drive how these are tackled.

Red Risk Exposure Mitigation Strategy: The mitigation strategy and execution should be assigned to a risk owner. The project team needs to work together to find outlets to avoid or temper the severity of the risk at hand. If the risk is accepted, it's critical that every stakeholder understand the consequences.

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 411

What is the rate base total of IT&S expenses for each year from 2019 through the Test Year?

Response:

Rate base IT&S expenditures are found in the “Intangible” and “General” categories of utility plant in service. The Intangible designation is fully comprised of IT&S capital expenditures. IT&S expenditures within the General category are isolated to FERC accounts 391.2 Computers, 391.21 Computer Horizon, and 391.22 Computer Bloodhound.

Please see “UG 490 OPUC DR 411 Attachment 1.xlsx”.

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 414

Detail the payment terms for each of the contracts entered into for the IT&S projects included in Exh. 700. Include whether any prepayments were necessary for each project, if so, how much and when, the timeline of payments, and how many years this project is expected to provide benefits to customers and the Company.

Response:

NW Natural understands "payments terms" in this context to mean the condition triggering payment obligations for a contract. For each of the contracts entered into for the IT&S projects included in Exhibit 700, the payment terms were for 30 days after receiving an invoice (i.e., "Net 30").

Please see Confidential UG 490 OPUC DR 414 Attachment 1 for the requested information concerning those projects where prepayments were necessary.

Staff/1002
Dyck/19

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 415

Which IT&S projects are considered out of service in the Test Year but were previously included as capital projects?

a. Have these projects been moved into a regulatory asset account?

b. What amounts left are undepreciated? In other words, what are the remaining rate base amounts?

Response:

There are two IT&S projects that will be considered out of service at certain points during the Test Year but were previously included as capital projects. Those projects are:

UI Planner
Genesys

These projects are currently part of plant account 303.1-Computer Software.
The remaining rate base amounts as of 10/1/2023 are:

UI Planner - $331,789.40
Genesys - $3,404,683.86

Both IT&S projects are still in service today but are anticipated to be retired before the end of their original depreciable lives before or during the Test Year. Upon review, NW Natural did not include these projects in its forecasted retirements, and will update this in our Reply Testimony. These projects have not been moved into a regulatory asset. The Company uses the Group Depreciation Method which does not depreciate these assets individually, the total cost of the group is spread out over the useful life of the entire group. Through the depreciation study process the Company reassess the useful life and salvage value of the assets in each group, including retirements, and adjustments to depreciation rates may be made accordingly.

Please refer to the Company's response to UG 490 CUB DR 20 (due on March 22, 2024), which will provide more detailed information on the timing and estimated remaining balance on these two projects.

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 CUB DR 20

On NW Natural/100/Palfreyman-Kravitz/Page 16, in reference to "update[ing] its IT&S infrastructure, the Company states, "In this proceeding, NW Natural is seeking cost recovery of additional projects to further modernize its IT&S infrastructure and transition to cloud-based IT&S architecture. These upgrades are largely in response to cyber- security advancements, existing software reaching end of life and end of support, and developers exclusively providing cloud-based solutions." For the "existing software reaching end of life" please provide:

a. The in-service date of the software.
b. The useful life of the software when it was purchased and any changes to the useful life since then.
c. Any differences between the useful life and amortization period of the software if these periods ever differed.
d. The amount of money still in rate base for the software.
e. Any proposed changes to "d." in UG 490.
f. The Book Depreciation Reserve value of the software as of 10/1/2023.
g. The Future Accruals value of the software as of 10/1/2023.
h. A narrative explanation of how the software is still being used, if it is still being used, despite the addition/ transition to cloud-based software.

Response:

Please see "UG 490 CUB DR 20 Attachment 1" for subparts a-h. Upon review, NW Natural did not include these projects in its forecasted retirements and will update this in our Reply Testimony.

NW Natural's Response to DR 185 Attachment 1 is available in electronic spreadsheet format only.

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 424
Are contingency funds included in rate base or considered O&M expenses? Please point to where these are included in workpapers.

Response:

Contingency amounts may be included in forecasted project costs that are ultimately included in the forecasted rate base. There are no contingency funds included in O&M. The contingency funds, if included at the project level, would be embedded in individual capital project costs that are being closed and allocated to FERC accounts for rate base. There is no single place to point in a workpaper where contingency funds are layered into rate base; it would be embedded into the gross plant additions in UG 490 – Exh. 1713 – WP1 – Gross Plant and Accum Deprec – CONFIDENTIAL workpaper, Additions tab.

NW Natural

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 184

Have internal employees assisted in the implementation of any of the projects?
Response:

Yes, our internal employees play key roles in the implementation of all of our IT&S projects. Depending on the size and complexity of the project, internal staff may be involved in various capacities:

1. Subject Matter Experts (SMEs): Internal SMEs provide specialized knowledge and insights related to the project, guiding decisions, and offering expertise in specific areas such as software development, networking, cybersecurity, etc.

2. User Testing and Feedback: Internal employees may participate in user acceptance testing (UAT) to validate that the IT solution meets the organization's requirements and provides a satisfactory user experience.

3. Data Migration and Integration: Internal IT&S staff may assist in migrating data from existing systems to the new IT solution and integrating it with other systems within the organization.

4. Support and Maintenance: After implementation, internal IT&S support teams provide ongoing support and maintenance for the IT solution, addressing any issues that arise and ensuring smooth operation.

5. Documentation and Knowledge Transfer: Internal employees contribute to documenting processes, procedures, and best practices related to the IT project, facilitating knowledge transfer within the organization.

6. Vendor Management: Internal staff may interact with external vendors or consultants involved in the IT project, ensuring alignment with organizational goals, and overseeing contractual agreements.

By leveraging the skills and knowledge of internal employees, we optimize our resources, maintain institutional knowledge, and foster a sense of ownership and accountability throughout the IT project lifecycle.

Staff/1002
Dyck/24

NW Natural's Response to DR 159 Attachment 1 is available in electronic spreadsheet format only.

Staff/1002
Dyck/25

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 357

The Company describes its need for eight new Information Technology and Services FTEs in NW Natural/700, Downing/50-55. The Company states these positions are needed to adequately staff H2: Vista. While this project will not begin in 2024, the Company states the new positions are needed now for education and integration. When does the Company intend to fill these positions?

Response:

To clarify, only four out of the eight full-time equivalents (FTEs) listed in the NW Natural/700, Downing/50-55 testimony are essential to support Horizon 2: Vista (H2: Vista). The other four FTEs are needed to support NW Natural's SCADA telemetry systems, gas/pipeline control operations, and identity governance administration. (See NW Natural/700, Downing/53-55.)
With respect to the four FTEs necessary to support H2: Vista, the Company intends to immediately begin recruiting three of the four positions, and expects all four positions to be hired prior to the rate effective date (i.e., November 1, 2024), although the exact dates will depend on finding qualified candidates. As explained in NW Natural/700, Downing/51-52, filling these positions in a timely manner is crucial to effectively supporting NW Natural's ongoing CIS needs, while simultaneously allowing existing personnel to develop, test, and implement H2: Vista. NW Natural's legacy, 26-year-old CIS is highly complex, requiring substantial lead times of between 18-24 months for new personnel to be effectively educated and integrated. Robust training is essential to ensure that the legacy CIS continues to support reliable, seamless continuity of service for customers during the H2: Vista development and implementation. Given that NW Natural is already well into the planning stage of H2: Vista, including developing a comprehensive framing study, filling these four FTE positions quickly is imperative to ensure adequate capacity to advance the H2: Vista development and support the legacy CIS.

Staff/1002
Dyck/26

NW Natural's Response to DR 160 Attachment 1 is available in electronic spreadsheet format only.

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 419

Does the Company have an update on the timing of the deferral for the Horizon 2 project?

Response:

The Company's currently plans to file the Horizon 2, or H2: Vista, deferral application in the third quarter of 2024. The Company will update its plans in its Reply Testimony.

Staff/1002
Dyck/28

NW Natural's Response to SDR 58 Attachment 2 is available in electronic spreadsheet format only.

NW Natural

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 408

See UG 490 - Exh. 1400 - OM Model Workpaper_Non-Confidential, tab Dept Non-Payroll Forecast, and filtered by Test Year (TY) Adjustments (Highlighted in yellow) for FERC 921.

Cost Center	Cost Center	GL Accou	GL Account	FERC	I/O	Test Year	
10710	INFRASTRUCTURE-OFFIC	608100	TEST YEAR ADJUSTMENT - SUBCRIPTION SERVICES	921		$664,974	$586,028
10710	INFRASTRUCTURE-OFFIC	605600	TEST YEAR ADJUSTMENT - SOFTWARE MAINT	921		$4,846,188	$4,270,847
10710	INFRASTRUCTURE-OFFIC	605900	TEST YEAR ADJUSTMENT - HARDWARE MAINT	921		$214,517	$189,050
10710	INFRASTRUCTURE-OFFIC	606300	TEST YEAR ADJUSTMENT - CELLULAR PHONES	921		$238,493	$210,179
10710	INFRASTRUCTURE-OFFIC	602300	TEST YEAR ADJUSTMENT - RENTS AND LEASES	921		$32,518	$28,657
10818	REGULATORY AFFAIRS-O	605100	TEST YEAR ADJUSTMENT - PROFESSIONAL SERVICE	921		$153,196	$135,009
10831	LEGAL FEES-RATES-OFF	605000	TEST YEAR ADJUSTMENT - LEGAL FEES	921		$908.519	$800.659

a. Why are the TY totals for each month not referencing the IT&S TY Forecast tab, whereas rows for other cost centers reference different respective tabs? In other words, where are the numbers coming from that are in cells AV 2329 through BG 2329?

b. Why are professional services and legal fees included in FERC 921?

c. Were the amounts in (b) above discussed in Exh 1400.

Response:

a. Unlike the other adjustments in the workpaper where one line is adjusted to reflect higher or lower expense, IT&S expected increases from the Base Year to the Test Year are occurring across the entire IT&S organization on many different GL accounts and many different Cost Centers. IT&S forecasts a Test Year increase of $7,729,571 which included escalation. That can be found in the OM workpaper IT&S TY Forecast tab cell I92. The adjustments were hard coded each month in the model to get to the forecasted $7.7M.

This can be confirmed by going to the Dept Non-Payroll Forecast tab and filtering to the IT&S cost centers (10259-10282, 10705-10739 & 11128). The Base Year amounts can be added up using column BL which adds to $28,609,172. The Test Year amounts are in column BH which adds to $36,338,742, an increase of $7,729,571.

In hindsight, this adjustment could have been performed more clearly in the workpaper to make reviewing easier.

b. Professional services and legal fees are included in FERC 921 because they are estimated amounts to be incurred for prosecuting this case, i.e. “rate case expense”.

c. No, they were not discussed in Exh. 1400.

Staff/1002
Dyck/31

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 409

Why are the amounts the same in every month of the test year for the FERC 921 associated IT&S expenses? For example, cells AV 2329 through BG 2329 are $55,415 in each cell.

Response:

While the workpaper/model includes monthly amounts for gross up inflation, the IT&S adjustments were made with the intention to bring the Total 12-month Test Year amount in line with the forecasted increase. IT&S adjustments were made to increase the total IT&S Test Year amount by $7.7M. How the expenses were allocated to each month in the workpaper was not an emphasis, so the Company spread those expenses equally to each month.

Staff/1002
Dyck/32

NW Natural's Response to DR 411 Attachment 1 is available in electronic spreadsheet format only.

CASE: UG 490
WITNESS: JULIE DYCK

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1003

CONFIDENTIAL
Exhibits in Support Of
Opening Testimony

April 18, 2024

Staff/1003
Dyck/1

NW Natural Confidential

Staff/1003
Dyck/2

NW Natural's Response to CONF DR 414 Attachment 1 is available in electronic spreadsheet format only.

CASE: UG 490
WITNESS: ANNA KIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1100

Redacted Opening Testimony

April 18, 2024

Docket No: UG 490

Staff/1100
Kim/1

Q. Please state your name, occupation, and business address.

A. My name is Anna Kim. I am the Energy Costs Section Manager employed in the Rates, Safety and Utility Performance Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/1101.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss long-term hedging policy and Schedule H, Large Volume Non-Residential High Pressure Gas Service Rider for Compressed Natural Gas service.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared Exhibit Staff/1101, my witness qualifications statement, and Exhibit Staff/1102, a compilation of responses to data requests referenced in this testimony.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Long-Term Hedging 2
Issue 2. Schedule H 8

Docket No: UG 490

Staff/1100
Kim/2

ISSUE 1. LONG-TERM HEDGING

Q. What is long-term hedging?

A. In this context, hedges are investments that are undertaken to limit risk from high gas prices. Short-term hedges are typically transactions that address the next heating season and medium-term hedges are typically transactions to hedge gas supply costs two and three years out. Long-term hedges are transactions (financial and physical) that hedge gas purchase costs more than three years in the future.[1]

Q. How does the Company recover the costs of long-term hedges?

A. NW Natural recovers costs of long-term hedges through its Purchased Gas Adjustment (PGA) Mechanism. The PGA is an automatic adjustment mechanism that allows NWN a to update rates to capture changes in its purchased gas costs on an annual basis without the need for a general rate review. The PGA includes both a forward-looking and backward-looking component. For the forward-looking component, the Commission allows NWN to reset rates annually with an updated forecast of purchased gas costs. For the backward component, NWN is allowed to defer the variance between forecasted and actual purchased gas costs and given the opportunity to recover that variance in future rates, subject to sharing, a prudence review, and a review of the Company's earnings during the deferral period.[2]

[1] LC 60 NW Natural 2014 IRP, p. 3.39.
[2] *In the Matter of the Public Utility Commission of Oregon Investigation into the Purchased Gas Adjustment (PGA) Mechanism Used by Oregon's three Local Distribution Companies*, UM 1286, Order No. 08-504 (October 21, 2008).

The purpose of the PGA is two-fold: (1) to allow the gas utilities to recover costs associated with the purchase and transportation of natural gas to its systems and (2) to provide an incentive (i.e., the sharing) to minimize the cost of natural gas purchases.

Q. Is long-term hedging specifically addressed in the PGA?

A. In a way. In 2015, the Commission opened an investigation into the long-term hedging policies of Oregon's three natural gas local distribution companies, docketed as UM 1720. Parties to that docket engaged in workshops to determine whether they could agree on guidelines for long-term hedging, but ultimately decided they could not due to the diversity of the available hedging instruments and optionality to the duration and timing of the hedges.[3] Instead, the parties agreed to a process that the gas companies could use to receive feedback from stakeholders regarding long-term hedges.[4] The parties proposed that this process be incorporated into the Commission's Natural Gas Portfolio Development Guidelines that gas utilities must follow in connection with making the Companies' PGA filings. The Commission subsequently adopted the parties' recommendation in Docket No. UM 1286.[5]

Q. Why is long-term hedging an issue in this proceeding?

A. In January 2024, the Company entered the long-term hedging review process as laid out in UM 1286 and the Natural Gas Portfolio Development Guidelines.

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[3] *In the Matter of NW Natural Gas Company, dba NW Natural, Investigation into Long-Term Hedging Policy*, UM 1720, Order No. 18-019, pp. 1-2 (January 18, 2018).
[4] *Id.*
[5] UM 1286(4), supra, Order No. 18-144, App. A (May 1, 2018).

While engaging in this process, Staff identified opportunities to better align benefits of long-term hedges to the Company and to customers. Staff addresses this topic here to propose a change to how the costs of long-term hedges are recovered in NWN's annual PGA.[6]

Q. What is the review process for long-term natural gas hedging strategies for natural gas utilities?

A. If the utility identifies a long-term hedging strategy that it believes is in the interest of customers, the utility requests a meeting with stakeholders, including Staff, the Oregon Citizens' Utility Board, and the Association of Western Energy Consumers (formerly Northwest Industrial Gas Users).[7] In the meeting, the utility shares the proposal. Stakeholders have 30 days to provide a written response on whether they support the utility moving forward or if there are reservations and concerns. If any stakeholder believes the proposal needs further review by the Commission, said stakeholder would utilize the process outlined above to identify the appropriate forum for review.

Q. How often has this hedging review process been implemented by the Company?

A. Northwest Natural engaged this process for the first time in January 2024.

Q. When Staff engaged in this process, what did Staff find?

[6] NWN and the other natural gas companies in Oregon make their annual PGA filings on or around August 1 of each year.

[7] *In the Matter of the Public Utility of Oregon Investigation into the Purchased Gas Adjustment (PGA) Mechanism Used by Oregon's Three Local Distribution Companies*, UG 1286(4), Order No. 18-144, App. A, p. 3.

A. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** The requirements for information shared in this process were vague as written. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Q. What does Staff propose now?

A. Staff does not propose any change to the notice and meeting process utilities should use for proposing long-term hedging proposals adopted in Order No. 18-144. However, Staff proposes 90/10 sharing on costs of long-term hedges that exceed five percent of total gas purchases. Meaning, for any long-term hedge that exceeds the five percent of total gas cost threshold, NWN would only be allowed to include 90 percent of the cost in forecasted rates.

Q. Why is this appropriate?

A. In theory, a gas utility could use hedges to significantly limit the risk of non-recovery of actual purchased gas costs in the PGA. As noted above, the PGA allows the gas utility to recover the variance between its forecasted and actual gas prices, subject to sharing and an earnings and prudence review. If the

utility hedges all of its purchased gas, the utility's forecasted costs and actual costs would be the same and there would be no variance. Accordingly, the utility's recovery of its actual costs would not be subject to sharing or an earnings review.

The 90/10 sharing in the PGA is designed to incent the utility to minimize its purchased gas costs. Because the cost of long-term hedges will likely not vary between the forecasted and actual costs, there is no sharing of these costs. Accordingly, requiring the utility to absorb 10 percent of the cost of long-term hedging transactions will help ensure the Company acts in a manner that is in the best interests of both customers and the utility.

Q. Why does Staff only make this recommendation for hedging costs that exceed the five percent of total costs threshold?

A. Staff recommends a five percent of total purchase requirement as a "safe" limit that utilities could "lock in" long term prices as this is a small amount as a reasonable threshold before additional action. Amounts greater than this, however, should include a sharing component. The reason being that reducing price risks benefits both the Company and the customer. The Company benefits as it removes that amount of gas from having price risk ad subject to the PGA sharing. The alignment of incentives helps ensure the Company enters long-term hedging with careful analysis and is in the Company's best interest.

Docket No: UG 490

Staff/1100
Kim/7

Q. What would be the ratemaking treatment Staff proposes for any long-term hedge the Company enters into for those above the five percent of total retail load?

A. Staff proposes that long-term hedges above five percent of total retail load be presumed reasonable and prudent by evidence of the fact that the Company bears ten percent of the "above market" cost of the contract. The Company would continue to provide notice and hold a meeting with stakeholders.

Q. What do you mean by the "above market" cost of the contract?

A. There is a forward price curve for the natural gas market. To "lock in" those prices, presumably there would need to be a premium to pay. The premium would be deemed the above market cost.

Docket No: UG 490 Staff/1100
Kim/8

ISSUE 2. SCHEDULE H

Q. What is Schedule H?

A. Scheule H is the Large Volume Non-Residential High Pressure Gas Service Rider for Compressed Natural Gas service. There are currently two (2) customers on Schedule H. There was only one in 2019-2022.[8]

Q. Is Schedule H covered in this GRC?

A. No. Schedule H is removed from the revenue requirement model.[9]

Q. What is the Company proposing for Schedule H in this GRC?

A. The Company is updating Schedule H with new cost of capital components as well as capital investment cost and O&M assumptions for cost of service.[10] This is a standard update consistent with updates in the last GRC.[11]

Q. Where else does Staff review changes to Schedule H?

A. Updates are reviewed through advice filings. ADV 1472/Advice No. 22-23 is the last advice filing with changes to Schedule H. ADV 1472 extended the end date of this service until January 31, 2025.

Q. What did Staff conclude when reviewing Schedule H for ADV 1472?

A. In Staff's memo for the January 24, 2023, Public Meeting, Staff recommended approving the extension of this service. Staff found that the compressed natural gas fuel market has not appreciably changed since 2018. NW Natural is

8 NWN Response to Staff DR 219.
9 NWN/1700, Walker/17.
10 NWN/1700, Wyman/58.
11 UE 435 NWN/1300, Walker/25.

providing a beneficial service to customers because it may not otherwise be available without the utility's involvement in the market.

Q. Have there been any changes to the market since?

A. Staff requested an update in DR 433. The Company has not seen any appreciable change in the compressed natural gas market since the last update filed in ADV 1472.

Q. Do you have any recommendations?

A. Not at this time.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 490
WITNESS: ANNA KIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1101

Witness Qualifications Statement

April 18, 2024

Docket No. UG 490 Staff/1101
Kim/1

WITNESS QUALIFICATIONS STATEMENT

NAME: Anna Kim

EMPLOYER: Public Utility Commission of Oregon

TITLE: Energy Costs Section Manager
Rates, Safety and Utility Performance Program

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION: Master of Science, Economics
Portland State University,
Portland, OR

Master of Environmental
Studies, The Evergreen State
College, Olympia, WA

Bachelor of Arts, Environmental
Science, University of California,
Berkeley, CA

EXPERIENCE: I have been employed by the Oregon Public Utility Commission (OPUC) since July 2018 in the Energy Resources and Planning Division. My responsibilities include providing advice on energy efficiency policy, pilot and program evaluation, and oversight of energy efficiency programs run through the Energy Trust of Oregon

Prior to working for the Commission, I worked for Seattle City Light as a power resource planner developing integrated resource plans. I also worked for five years as an evaluation consultant which involved evaluating energy efficiency and demand response pilots and programs and market research.

CASE: UG 490
WITNESS: ANNA KIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1102

Exhibits in Support
Of Opening Testimony

April 18, 2024

Staff/1102
Kim/1

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 219

Please provide the number of accounts under Schedule H for the Test Year and the last five previous years.

Response:

Schedule H investments are evaluated on a separate cost of service basis relative to core utility assets; costs and revenues associated with this schedule are removed from the Company's revenue requirements models. Therefore, there are zero Schedule H customers included in the Test Year in this rate case proceeding.

There are, however, two customers taking service on Schedule H as of February 1, 2024. The number of customers taking service on Schedule H at December 31 over the past five years are as follow:

2019: 1
2020: 1
2021: 1
2022: 1
2023: 2

Staff/1102
Kim/2

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 221

Please describe the Company's understanding of the OPUC's policy and direction regarding the ratemaking treatment of long-term hedging.

a. Please list and discuss past Orders that relate to treatment and direction to parties.

Response:

The Company objects to this data request under OAR 860-001-0500, in that the information requested is not relevant to issues in a rate case. Notwithstanding this objection, the Company is aware of two Commission orders related to long term hedging: Order Nos. 18-019 and 18-144.

Staff/1102
Kim/3

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 433

Please provide:

a. An update on the compressed natural gas market since the Company's last report in ADV 1472/Advice No. 22-23; and

b. A description of any notable changes to the CNG market, including number of public and private fueling stations.

Response:

For ease of reference, the Company provides its Schedule H – Large Volume Non-Residential High Pressure Gas Service (HPGS) Rider tariff extension request and market report in ADV 1472/Advice No. 22-23, dated December 15, 2022, as UG 490 OPUC DR 433 Attachment 1. The Company also provides Staff's report and recommendation in ADV 1472/Advice No. 22-23, dated January 13, 2023, as UG 490 OPUC DR 433 Attachment 2.

a. The Company finds that the Compressed Natural Gas ("CNG") market has not markedly changed since the Company's tariff extension request was filed and Staff's report was issued on December 15, 2022, and January 13, 2023, respectively. The Company did add one new customer to its Schedule H service in 2023 (City of Wilsonville). Further, the Company continues to engage with potential customers and industry partners that remain interested in moving diesel vehicle fleets to CNG. Diesel prices, while generally trending down after reaching a five-year high in 2022, remained volatile throughout 2023 and early 2024. The Company currently has three open inquiries to explore the feasibility of constructing CNG stations for service under Schedule H.

   The key difficulties potential developers have expressed in building CNG stations are lack of state incentives for a comprehensive network of stations and lack of commitment from fleet owners and operators. Companies with the capital to convert/purchase CNG fueled fleets that would make a CNG station economically viable are hesitant to invest in CNG vehicles because there is a sense of uncertainty about whether CNG will qualify under state clean fuels/carbon reduction programs in the near future. Companies with a nationwide presence are hesitant to convert their Oregon-based fleet to CNG as they prefer to use the same types of vehicles and

fuels in every state. Additionally, many smaller companies rent their fleets and even if they would prefer CNG, the fleet owner may not be incentivized or find it economically viable to offer CNG vehicles as an option.

The Company continues to find on-going interest in CNG within its service territory under current market conditions and despite the difficulties cited above. The Company finds that the conclusion from Staff's report is still valid, namely "…that NW Natural is providing a service [through the HPGS] that would not otherwise be available to customers without the utility's involvement in the market. [The] HPGS program provides a benefit to existing customers and a possible scenario can arise where if low CNG prices persist, diesel fleets can have incentives to convert to CNG thus further fueling CNG market development."[1] [2]

b. According to the US Department of Energy's Alternative Fuels Data Center, there are a total of three public and 10 private CNG fueling stations in Oregon as of March 2024. This count does not include the City of Wilsonville CNG fueling station. Additionally, there is one public liquified natural gas ("LNG") fueling station that sells renewable natural gas ("RNG").[3] In total, the Company finds there are 15 CNG and LNG fueling stations in Oregon. Staff's report identified 14 CNG stations as of 2023, which led Staff to conclude that this number indicated that the CNG market "has not changed appreciably" since 2018.[4]

[1] *See*: UG 490 OPUC DR 433 Attachment 2, page 6.
[2] For the US Department of Energy Alternative Fuel Price Report, see: Alternative Fuels Data Center: Fuel Prices (energy.gov). As of January 1, 2024 CNG averaged $2.95 per gasoline gallon equivalent ("GGE") while diesel averaged $3.51 per GGE.
[3] US Department of Energy Alternative Fuels Data Center, natural gas fueling station locations data can be accessed here: Alternative Fuels Data Center: Natural Gas Fueling Station Locations (energy.gov).
[4] *See*: UG 490 OPUC DR 433 Attachment 2, page 5.

CASE: UG 490
WITNESS: CHARLES LOCKWOOD

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1200

Opening Testimony
Uncollectible Accounts and
Schedule 330 Residential Bill Discount Program

April 18, 2024

Docket No: UG 490

Staff/1200
Lockwood/1

Q. Please state your name, occupation, and business address.

A. My name is Charles Lockwood. I am a Utility Analyst employed in the Utility Strategy and Integration Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/1201.

Q. What is the purpose of your testimony?

A. I provide background, analysis, and recommendations regarding the Company's Test Year amount for Uncollectible accounts and the Company's Schedule 330 Residential Bill Discount Program.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared the following exhibits:

- Exhibit Staff/1202, NW Natural Response to DR 296.
- Exhibit Staff/1203, Staff Workpaper on Uncollectible accounts.
- Exhibit Staff/1204, NW Natural's Response to DR 318.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Uncollectible Accounts 3
Issue 2. Residential Bill Discount Program 21
Summary of Staff Recommendations 29

Q. Could there be changes or updates to Staff's position and recommendations?

A. Yes. My testimony represents issues identified to date. My recommendations and issues may change when informed by new data and after reviewing testimony and analysis by other parties.

Docket No: UG 490

Staff/1200
Lockwood/3

ISSUE 1. UNCOLLECTIBLE ACCOUNTS

Q. Please provide a summary of the Commission's historical treatment of uncollectible accounts.

A. It is a long-standing policy of the Commission Staff to apply a three-year average methodology to determine the Test Year amount for uncollectible accounts for a utility's revenue requirement.[1] Commission Staff also examines other evidence to determine whether this approach results in a reasonable forecasted Test Year result. The amount included in a utility's revenue requirement for uncollectible accounts is revenue sensitive because it depends on the amount of forecasted revenue. That is, the total amount for uncollectible accounts included in the revenue requirement is a function of the Test Year revenue and the uncollectible rate.

Q. Describe the Company's proposal for Test Year uncollectible accounts.

A. The Company's Test Year forecast for uncollectible accounts is $4.49 million, which is approximately $3.8 million higher than the amount recorded in 2021 for uncollectible accounts of $690 thousand. The Company forecasts a Test Year uncollectible rate of 0.491, percent which is approximately five times the

[1] *See, e.g., In the Matter of Avista Corporation*, UG 246, Order No. 14-015 at 3 (January 21, 2014) and *In the Matter of Avista Corporation*, Docket UG 186, Order No. 09-422, Appendix A at 4 (October 26, 2009) (adopting stipulations for Avista general rate increase with uncollectible expense in revenue requirement based on three-year average); *but see In the Matter of Idaho Power Company*, UE 167, Order No. 05-871 (January 28, 2005) (adopting stipulation for Idaho Power Company general rate increase with uncollectible expense based on four-year average) and *In the Matter of Cascade Natural Gas Corporation*, UG 287, Order No. 15-412 (December 28, 2015) (adopting stipulation for Cascade Natural Gas general rate increase with uncollectible expense based on three-year average, removing an anomalous year).

Company's uncollectible rate of .097 percent from Northwest Natural's last GRC in Docket No. UG 435 in 2022.

Q. What uncollectible rate is obtained using the three-year average methodology described above?

A. The three-year average methodology produces an uncollectible rate of 0.182 percent.

Q. Does the Company use the three-year average methodology to derive its proposal for the Test Year uncollectible accounts?

A. No. The Company's proposed 2024-2025 amount for uncollectible accounts is calculated using an uncollectible rate that is forecasted using a combination of historical uncollectible rate trends, with adjustments for NW Natural's agreement to stop collecting residential customer deposits, changes to the collections and disconnection process adopted in the Division 21 rules, current macroeconomic factors such as inflation and higher interest rates, and federal regulation changes for collection agencies.[2]

Q. Please explain the Company's process for forecasting the 2024-2025 uncollectible rate.

A. The Company's starting point for the uncollectible rate forecast is the UG 435 approved uncollectible rate which is also the three-year average of the uncollectible rate between 2017-2020 (0.097 percent). The Company utilized this three-year historical average to avoid including months affected by the

[2] NW Natural/1300, Wilson-Sparley/5.

COVID-19 pandemic.[3] The Company then adds six distinct adjustments to the baseline uncollectible rate of 0.097 percent, all of which increase the uncollectible rate. The Company's adjustments are for:

- Weaker Economic Conditions
- Deposits No Longer Collected
- Division 21: Temperature/Weather/Wildfire/AQI/Shortened Day
- Division 21: Customer Notice Chance 15 to 20 Days
- Collection Agency Reduced Recoveries
- Discontinued Arrearage Management Program

Figure 1 provides an overview of the Company's proposed adjustments and the associated calculated adjustment amount to the baseline uncollectible rate.[4]

Figure 1. Proposed Uncollectible Rate Adjustments

Baseline Uncollectible Rate 2017-2019	0.097%
Weaker Economic Conditions	0.100%
Deposits No Longer Collected	0.137%
Division 21: Temperature/Weather/Wildfire/AQI/Shortened Day	0.029%
Division 21: Customer Notice Change 15 to 20 Days	0.007%
Collection Agency Reduced Recoveries	0.071%
Discontinued Arrearage Management Program	0.050%
	0.491%

Q. Please describe the Company's Economic Conditions Adjustment.

[3] NW Natural/1300, Wilson-Sparley/4.
[4] NW Natural/1300, Wilson-Sparley/12.

A. The Company states in testimony that "uncollectible expense typically increases during times of economic downturns."[5] To calculate how NW Natural's presumed current economic condition would impact the uncollectible expense Company averaged the uncollectible rates during previous technical economic recessions to arrive at 0.40 percent. The Company states the 0.40 percent is approximately 0.15 percentage points higher than the average uncollectible rate experienced in non-recessionary periods.[6]

However, given that the economy is weaker according to NW Natural but not in a technical recession today, the Company chose to use a 0.10 percent impact. While this is a decrease from the recession-based calculation of 0.15 percent, this is quite an increase for NW Natural's overall uncollectible rate. This increase alone more than doubles the Company's overall uncollectible rate of 0.097 percent to 0.197 percent.

FIGURE 2. NW NATURAL ECONOMIC CONDITION ANALYSIS

Methodology	Uncollectible Rate	Difference	Change From Currently Approved Rate
Non-Recessionary Periods	.25%	N/A	+0.153%
Technical Recession (2001-2002, 2007-2009)	.40%	+.15%	+0.303%

[5] Id.
[6] Id.

Adjustment Technical Recession	.35%	**+.10%**	+0.253%

The Company points to several indicators to justify to current macro-economic environment being weaker than in the pre-COVID-19 timeframe of 2017 through early 2020, when the Company last calculated the historical average uncollectible rate used in Docket No. UG 435. These indicators include:

- Interest rates increasing at the fastest rate in thirty-five years;
- The Personal Saving Rate decreasing from 6.4 percent in December 2019 to 3.4 percent in September 2023; and
- Increases in inflation rate, the consumer price index, and national delinquency rate on credit card loans.[7]

Overall, the Company argues that the risk of a recession remains elevated heading into 2024 and these factors create a weaker macroeconomic environment today compared to the Company's baseline period of 2017-2019.

Q. Does Staff agree with the Company's proposed Economic Conditions adjustment?

A. No. Staff believes that the Company fails to adequately justify the estimate of the economy's impact used in the calculation for the Weaker Economic Conditions adjustment. Staff is concerned with the use of the average uncollectible rate between 2001-2002 and 2007-2009 within the Company's

[7] NW Natural/1300, Wilson-Sparley/11, and Federal Reserve Economic Data.

calculations. NW Natural provides little to no substantive justification for their use of these time periods.

Staff believes the time periods selected by NW Natural represent too severe of an economic recession to be used by NW Natural in the calculation for this rate case. For example, the 2008 recession saw U.S. gross domestic product (GDP) decrease by 4.3 percent, making it the deepest recession since World War II.

Further, even if NW Natural can provide additional justification for the usage of these time periods, Staff remains concerned regarding the Company's downward rounding from the 0.15 percent difference in uncollectible rates during these technical economic recessions to calculate the 0.10 percent proposed. Staff feels that the methodology assumes conditions that raise the current uncollectible rate unrealistically, even with the slight downward adjustment. NW Natural notes the economy is weaker but is not in a technical recession today, therefore Staff is unclear if the 0.10 truly represents current economic conditions. Staff also did not find any further explanation from the Company regarding the calculation of the downward adjustment, as the Company's work papers do not provide reasoning.

Even with the Company applying a downward rounding adjustment of 0.05 percent, or one-third of the difference between total uncollectible rates during technical recessions and non-recessionary periods, Staff finds the use of these time periods improper and over states any needed adjustment. Staff

requires further information and justification from the Company regarding the overall calculation and downward adjustment made.

Q. Please describe the Company's Deposits No Longer Collected Adjustment.

A. The Company proposes to increase the uncollectible rate by 0.137 percent because the Company permanently stopped collecting deposits from residential customers because of the stipulation adopted in Docket No. UG 436 regarding NW Natural's Schedule R, Residential Arrearage Management Program.[8] The Company represents that the increase of 0.137 is reflective of the $600,000 NW Natural refunded on average in deposits on customers closing bills, given that $600,000 is 0.137 percent of the Company's annual residential gas revenues between 2017 and 2019. The Company states the $600,000 refunded on average assisted the customers and reduced potential write-offs, as when a customer closed their account, any deposit being held by the Company would be credited on the customer's closing bill. Because of this, the Company finds it is reasonable to expect that the lack of collected deposits will increase the uncollectible rate by 0.137 percent.

Q. Does Staff agree with the Company's proposed Deposit Adder adjustment?

A. No. The Company fails to provide any evidence that the end of deposits has led to an increase in uncollectible accounts to date. Staff finds the Company has not clearly articulated the relationship between not collecting deposits and

[8] NW Natural/1300, Wilson-Sparley/13.

an increase to the uncollectible accounts. Staff requests in the Company's Reply Testimony more information clarifying if the customers closing accounts were overdue on payments or if part of the $600,000 was being returned.

Additionally, the Company's deposit adder adjustment calculation assumes that the level of write-offs associated with residential deposits that occurred in 2017-2019 will remain constant and unchanged into the Test Year. The Company's calculation does not allow for any year-over-year variance and fails to consider that the end of deposits coupled with other measures targeted at alleviating residential customers' energy burden will lead to a lower overall level of write-offs for customers.

Q. Please describe the Company's Division 21: Temperature/Weather/Wildfire/AQI/Shortened Day Adjustment.

A. The Company states in testimony that the changes to the OAR Ch. 860, Div. 21 (Division 21) rules regarding shorter time frames for technicians to visit customers and collect payments and the new weather moratoriums will increase the uncollectible rate by 0.029 percent.[9]

Q. Please describe how NW Natural states the Division 21 Rule changes will affect the Company's uncollectible rate.

A. Prior to the Division 21 rule changes, NW Natural technicians would work until 4:00 PM, however, the new rule requires all technicians to stop field credit orders by 2:00 PM. The Company estimates this is a time reduction of

[9] NW Natural/1300, Wilson-Sparley/15.

25 percent, which equates to approximately 52 days a year lost as a result of this rule.[10]

In addition, there were two weather moratoriums updated by the Division 21 rule changes. First, the "cold weather moratorium prohibits the Company from disconnecting customers if the weather is or is forecasted to be less than thirty-two degrees or when there is a winter storm warning indicating weather conditions pose a threat to life or property."[11] NW Natural states this results in approximately twenty-eight days a year of inability to completely field credit orders in one or more of the areas within the Company's territory in 2022.

The second weather moratorium updated by the changes to the Division 21 rules prohibits technicians from completing field credit orders if the Air Quality Index (AQI) is 100 or above, resulting in approximately four days of inability to complete field credit orders in 2022.[12]

Overall, the Company is unable to complete credit field orders approximately eighty-four days per year.[13] The Company states "[t]he longer a customer is allowed to continue using gas service without payment, results in a higher bill and eventually leads to a higher uncollectible expense."[14] Therefore, using the 2022 net write-off rate and 2023 budgeted residential revenues, NW Natural found its daily net write-off is $3,723, meaning the total of incremental

[10] NW Natural/1300, Wilson-Sparley/14.
[11] Id.
[12] NW Natural/1300, Wilson-Sparley/14-15.
[13] Id.
[14] Id.

write-offs for the 84 day reduction would equate to $313 thousand or 0.029 percent of total 2023 budgeted revenues.[15]

Q. Does Staff agree with the Company's Division 21: Temperature/Weather/Wildfire/AQI/Shortened Day Adjustment?

A. No. The Company provides no data to validate the claim that these protections will increase the uncollectible rate. The Company's adjustment calculation broadly assumes that all customers will accrue balances uniformly and that these protections will have no effect on reducing overall disconnections. Staff finds this adjustment to be presumptuous and not backed by any evidence to date. Staff believes that the impacts of the rule change on the uncollectible rate is yet to be fully understood and therefore disagrees with the proposed adjustment. Staff requires further information in the Company's Reply Testimony illustrating how its calculations are "conservative"[16] and if the Company has any updated information on impacts of the rule changes it has seen since the rule changes were adopted.

Q. Please describe the Company's Division 21: Customer Notice Change 15 to 20 Days Adjustment.

A. The Company states in testimony that due to increased notice time for customers facing interruption of service and change in Company practice, NW Natural expects an increase of 0.007 percent in uncollectible expenses.[17]

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15 Id.
16 Id.
17 NW Natural/1300, Wilson-Sparley/16.

To comply with the increased notice time of 15 to 20 days before interruption service in the most effective and efficient manner, the Company needed to remove its three-day call-ahead previously provided to customers.[18]

NW Natural states the Company historically received payment from 20 percent of customers it reached out to with the three-day call ahead. Therefore, to calculate the reduction in payments due to the removal of the three-day call ahead, the Company used the "September 2023 account balance aged 60+ days of $6.8 million and multiplied it by 20 percent to reach $1.4 million of accounts receivable that [the Company] would expect to collect from the three-day call ahead."[19] The Company then states it typically sees six (6) percent of accounts receivables turn into delinquent accounts that are deemed uncollectible, and therefore, written off, which equates to $81 thousand and represents 0.007 percent of the Company's 2023 budgeted total revenues.

Q. Does Staff agree with the Company's Division 21 Notice Division 21: Customer Notice Change 15 to 20 Days Adjustment?

A. No. It remains unclear to Staff why the Company is removing the three-day call-ahead due to the increased customer notice timeframe. Additionally, similarly to the Division 21 rule change adjustment, the Company does not provide any evidence that the updated rules have increased uncollectible expense to date. NW Natural fails to consider that the updated Division 21

[18] NW Natural/1300, Wilson-Sparley/15.
[19] NW Natural/1300, Wilson-Sparley/16.

rules were designed to offer greater protection to customers and ultimately help avoid further disconnections. The increased notice period may allow customers more time to make payments and ultimately avoid disconnection, thereby avoiding becoming uncollectible expense. Staff believes that the impacts of the rules change on the uncollectible rate is yet to be fully understood and therefore disagrees with the proposed adjustment.

Q. Please describe the Company's Collection Agency Reduced Recoveries Adjustment.

A. The Company states it has seen a decline in the number of recoveries received from collection agencies post-pandemic and requests an increase of 0.071 percent to the uncollectible expense.[20]

The Company notes recent changes to Consumer Financial Protection Bureau (CFPB) Regulation F (12 C.F.R. § 1006 and following), as a major factor in the decline of number of recoveries. Consumers now have more control over how collection agencies communicate with them and new restrictions on how agencies collect debts.

Overall, the Company has seen a decrease from recoveries in the years of 2014-2019, averaging 53 percent to 27 percent for 2022 and through October 2023.[21] The Company, therefore, applies the roughly 27 percent reduction in recoveries to its write offs, and proposes to increase the uncollectible rate by 0.071 percent.

[20] NW Natural/1300, Wilson-Sparley/17.
[21] NW Natural/1300, Wilson-Sparley/16-17.

Q. Does Staff agree with the Company's Collection Agency Reduced Recoveries Adjustment?

A. No. The Company's calculation uses just under two years of collection agency recovery rates to arrive at the recommended increase in the uncollectible rate. Staff believes that the focus on 2022 and 2023 recovery rates in this calculation is insufficient to justify the Company's proposed increase. Staff has examined the historic trend of recovery rates provided by the Company in Staff Data Request 296,[22] and while there is a decrease in 2022 and 2023, there is not a long enough time trend from which to infer that the recovery rate will not return to a historic baseline. Staff believes that there has not been adequate data to evaluate whether the new CFPB regulations will impact collection agency recovery rates at the same levels moving forward.

Q. Please describe the Company's adjustment for Discontinued Arrearage Management Program.

A. NW Natural states without the Arrearage Management Program (AMP), the Company projects an increase in the uncollectible rate of 0.05 percent.[23] Of the total write offs of $4.7 million between the months of May 2021 and December 2022, approximately $1.2 million were associated with accounts that had received AMP funds. By applying the post-pandemic collection agency rate of 27 percent, the Company calculates a new write off of $900 thousand, which equates to a 0.05 percent increase in the uncollectible rate.

22 Staff/1202, NW Natural Response to DR 296 (electronic spreadsheet).
23 NW Natural/1300, Wilson-Sparley/17.

Q. Does Staff agree with Company's adjustment for Discontinued Arrearage Management Program?

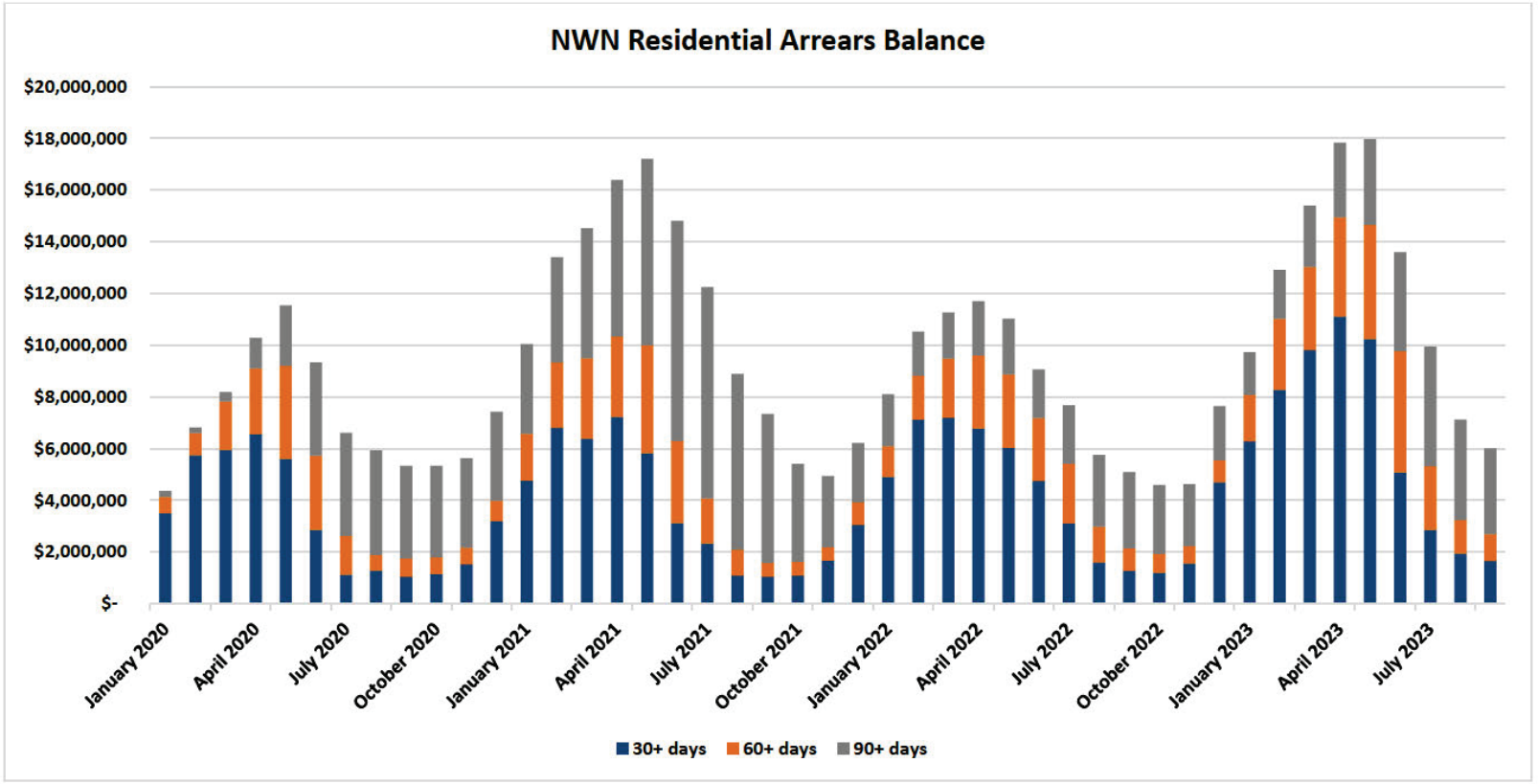
A. No. The Company argues that due to the expiration of the funds provided to customers through the Company's Arrearage Management Program (AMP) the uncollectible rate will increase. The Company's AMP was developed in response to the economic hardship faced by many individuals who lost the ability to pay their utility bills due to the COVID-19 pandemic. The AMP was meant as a temporary stopgap measure to alleviate arrears balances which increased during the pandemic. The expiration of the program does not necessarily indicate that the uncollectible rate will increase. The economic conditions that caused arrears to increase during the pandemic have subsided, and the Company's arrears remained cyclical in nature, shown in Figure 3.[24] Particularly, Figure 3 shows the Company's ninety-day arrears are declining significantly, while only the thirty-day arrears form the majority. Therefore, Staff believes that the Company has not provided sufficient evidence that the expiration of these programs will lead to an increase in uncollectible accounts.

[24] Docket No. RG 94, COVID-19 Monthly Report.

Docket No: UG 490

Staff/1200
Lockwood/17

FIGURE 3. NW NATURAL RESIDENTIAL ARREARS BALANCE



Docket No: UG 490

Staff/1200
Lockwood/18

Q. Please summarize NW Natural's application of its Bill Discount Program in the Uncollectible Expense calculations.

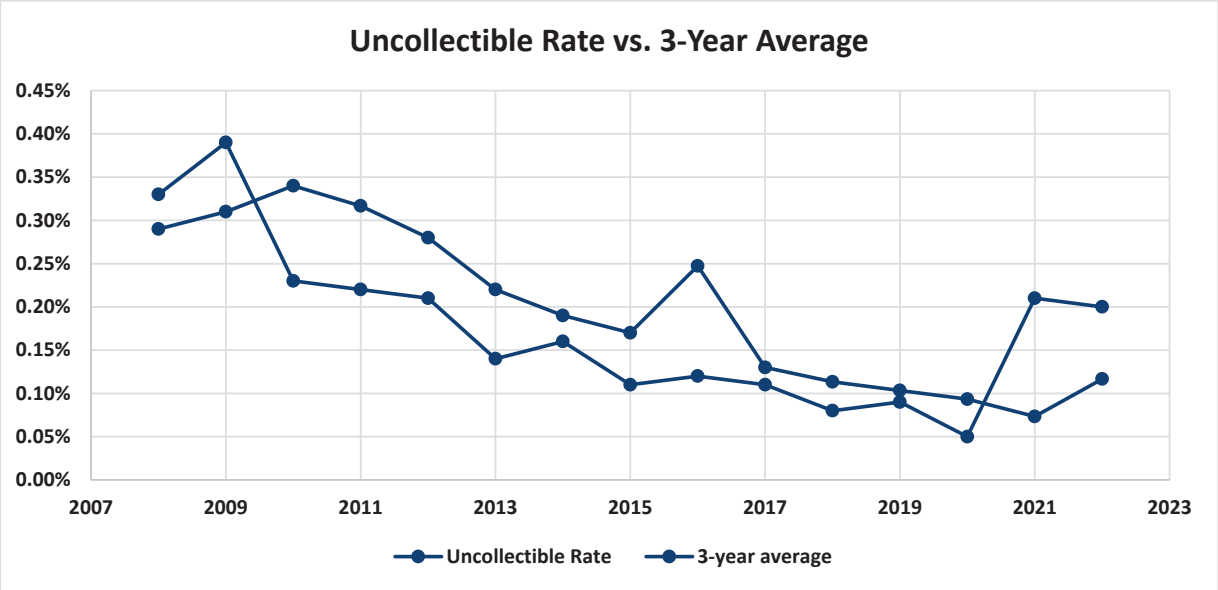
A. Staff finds the Company's lack of discussion surrounding the growth of its Bill Discount Program concerning. This concern is magnified by NW Natural's proposal to enhance and enlarge its Bill Discount Program in this docket without reflecting the impact this could have on its Uncollectible Expense. A program that provides relief to the customers that are likely to struggle the most to pay their bills on time could be expected to mitigate some amount of the uncollectible expense. The Company is proposing to recover on the bill discount program, while also receiving an uncollectible rate based on economic conditions, customer protections, and arrearage balance inputs, without discussing how this program may impact its overall uncollectible expense. Therefore, Staff finds the lack of discussion surrounding its impact on uncollectible expenses concerning. Staff requests further information from the Company in its Reply Testimony on its decision to not adjust the uncollectible expense based on increased participation and funding for the Bill Discount Program.

Q. Please summarize Staff's analysis of the overall methodology NW Natural uses to forecast the uncollectible rate.

A. Staff finds that the methodology put forth by the Company to forecast the uncollectible rate using distinct itemized adjustments is not sufficiently robust to justify deviating from the Commission's historic precedent of a three-year

average. Historically, the three-year average has tracked the overall trend of the uncollectible rate while smoothing out year-over-year variances. Figure 4 shows the Company's actual uncollectible rate plotted against the average uncollectible rate of the three preceding years.[25]

FIGURE 4. NW NATURAL UNCOLLECTIBLE RATE VS. 3-YEAR AVERAGE



Q. What is Staff's proposed adjustment for the uncollectible rate and uncollectible expense for the Test Year?

A. Staff proposes using the three-year average of the uncollectible rate between 2021 and 2023. NW Natural provided this average, an uncollectible rate of 0.182 percent, in the Company's testimony, as opposed to the .491 percent proposed.[26] Staff proposes applying this rate to the final agreed upon general revenues to calculate the appropriate level of uncollectible expense to be

[25] Staff/1203, Staff Workpaper, Uncollectible Rate.
[26] NW Natural/1300, Wilson-Sparley/18.

included in the Test Year. At this time, based on the Company's proposed general revenues in its Exhibit 201, Staff proposes a decrease of approximately $2.6 million to the Company's Test Year expense to account for a reduction to the amount forecasted by NW Natural for uncollectible accounts.

Docket No: UG 490

Staff/1200
Lockwood/21

ISSUE 2. BILL DISCOUNT PROGRAM

Q. Please provide background information on investor-owned utility bill discount programs in Oregon.

A. On January 1, 2022, House Bill (HB) 2475, The Energy Affordability Act, became effective. The bill expanded language in ORS 757.230 to include additional factors the Commission may consider when establishing rate classifications, such as the "differential energy burdens on low-income customers and other economic, social equality or environmental justice factors that affect affordability for certain classes of utility customers." The Commission's HB 2475 implementation strategy focused first on interim action to provide near-term relief under the new authority, to be followed by a longer-term investigation into differential rates and programs. Since HB 2475 became effective, Staff has been engaged with each of Oregon's six investor-owned utilities to implement interim bill discount programs that address low-income energy burden. The Commission has approved interim bill discount programs for Oregon investor-owned utilities in the following dockets:

- ADV 1365 – Portland General Electric,
- ADV 1412 – PacifiCorp,
- ADV 1390 – Northwest Natural,
- ADV 1409 – Cascade, and
- ADV 1410 – Avista.

Staff has found that reviewing utility proposals as independent advice filings facilitated a more accessible process, allowed more attention to be given to

the elements of the proposal, and provided an open communication venue that facilitated shared agreement and compromise to be reached prior to final approval.

Q. Please summarize the Company's current Residential Bill Discount Program.

A. Designed in 2022, NW Natural's current Residential Bill Discount Program, operational Schedule 330, is an income qualified percentage of bill discount program available to residential customers who were auto enrolled or demonstrate or self-attest that their gross household income, adjusted for household size, is at or below 60 percent of State Median Income (SMI). These customers may access a monthly discount of up to a 40 percent towards applicable charges. The Company currently has a four-tier discount structure with eligibility for each tier determined by household income and size, seen in Figure 6.[27] The four-tier structure was designed through conversations between the Company, Staff, and stakeholders to find a reasonable starting point.

Q. Please summarize the current participation in the Company's Bill Discount Program.

A. The program officially launched on November 1, 2022, with over 11,000 customers who had previously received energy assistance within the prior two years being auto-enrolled.[28] Since the launch, the enrollments have increased

[27] NW Natural/200, Tanaka/23.
[28] NW Natural/200, Tanaka/16.

to 37,222, representing 5.84 percent of all the Company's residential customers.[29] The estimated cost of the program in 2024 was approximately $8 million, with the largest portions of funding being spent on Tier 0 and Tier 3.[30]

FIGURE 5. NW NATURAL'S 2024 BILL DISCOUNT PROGRAM COSTS

Discount Tiers	Total Cost for 2024 ($)
Tier 0 (40%)	2,074,988
Tier 1 (25%)	1,863,105
Tier 2 (20%)	1,636,610
Tier 3 (15%)	2,356,280
Total:	7,930,984

Q. Please summarize the Company's proposed changes to the Bill Discount Program.

A. Conversations in Docket No. ADV 1390 and guidance from NW Natural's Low-Income Needs Assessment (LINA), has led the Company to propose two major changes to the program.

First, the Company is proposing to target the participant's bill after discount to be a percentage of the customer's income at or near three percent.[31] NW Natural states that a common indicator of energy burden is understood to be when a customer's energy bill is six percent of the customer's income. Therefore, the Company hopes to target three percent after discount

29 Id.
30 Staff/1204, NW Natural's Response to DR 318.
31 NW Natural/200, Tanaka/21.

to minimize energy burden. To calculate necessary levels of discounts, the Company has utilized the mid-point of the income range to determine the bill discount percentage instead of the max of the income range. The Company states that by "[u]sing the mid-point of the income range to determine the bill discount percentage for each tier provides better coverage of reduced energy burden throughout the tier."[32]

Second, the Company proposes to change the Tier 1 discount from 25 percent to 40 percent, and the Tier 0 discount from 40 percent to 80 percent. With the target of three percent energy burden related to natural gas service for customers, the Company chose to update the respective Tier discounts given the proposed rates in this docket and utilizing mid-points of income ranges instead of the max of each income range. The Company does not propose changes to Tier 2 and 3 discounts, which, based on the Company's methodology, were said to achieve the target three percent energy burden or less at their current levels.[33]

FIGURE 6. NW NATURAL'S CURRENT BILL DISCOUNT PROGRAM TIERS

	Adjusted Household Income	**Current** Discount Towards Eligible Charges	**Proposed** Discount Towards Eligible Charges
Tier 0	Up to 15% SMI	40%	80%
Tier 1	>15% up to 30% SMI	25%	40%
Tier 2	>30% up to 45% SMI	20%	20%
Tier 3	>45% up to 60% SMI	15%	15%

[32] NW Natural/200, Tanaka/23.
[33] Id.

Figure 7. Proposed Bill Discount Program Tiers and Example[34]

Bill Discount Program Impacts, Assuming Household of 4:	SMI 60% Tier 3 - 15%	SMI 45% Tier 2 - 20%	SMI 30% Tier 1 - 40%	SMI 15% Tier 0 - 80%
Income mid-point of tier	$56,246	$40,176	$24,106	$8,035
Average annual bill	$1,124.87	$1,124.87	$1,124.87	$1,124.87
Bill as % income before discount	2.0%	2.8%	4.7%	14.0%
Bill discount	$168.73	$224.97	$449.95	$899.90
Bill after discount	$956.14	$899.90	$674.92	$224.97
Bill as % income after discount	1.7%	2.2%	2.8%	2.8%

Note that this table reflects the rates for Residential Schedule 2 proposed in this case and income eligibility tables for 2023-2024.

Q. Does Staff agree with the proposed change utilizing the mid-point of the income range?

A. Not entirely. Staff appreciates the Company's effort to provide an energy burden targeted design as recommended in the UM 2211 process,[35] however, Staff is concerned that the mid-point of any income bracket does not necessarily correspond to the actual income distribution of enrollments within the Tier. For example, if enrolled customers incomes within a tier have a median below the mid-point of the income bracket, then the mid-point methodology underestimates the level of discount needed to achieve the three percent or below energy burden target.

Second, Staff is interested in providing a higher discount to the Tier 0 customers based on preliminary energy burden data Staff has seen from the

[34] NW Natural/200, Tanaka/24 (NW Natural's calculations).
[35] *In the Matter of PUBLIC UTILITY COMMISSION OF OREGON, Implementation of House Bill 2475*.

Company and peer utilities. However, rather than accept the mid-point methodology as sound, Staff would prefer to pursue the higher discount as an incremental step that may be refined and adjusted based on additional energy burden assessment information and stakeholder engagement.

Q. Does Staff agree with the proposed changes of the Tier 0 and Tier 1 discounts?

A. Not yet. While Staff appreciates the Company's efforts to move toward a more meaningful discount that endeavors to be informed by a target energy reduction methodology, Staff has two major concerns regarding the proposed change.

First, based on testimony, discussion with the Company, and DR responses received in this docket, Staff remains uncertain with the cost projections of the proposed changes and is specifically concerned with the potential increase in costs due to the increase discounts offered in Tier 0 and Tier 1. NW Natural has currently not completed any cost analysis on the implications of the redesign. Staff recognizes that cost recovery for the Bill Discount Program is not housed within the Company's revenue requirement in this docket and instead is funded through a deferral with a balancing account and an entirely separate amortization filed annually. However, Staff is uncomfortable moving forward with such large changes to the Bill Discount Program without a deeper understanding of the cost impacts of the changes.

Second, Staff's concern with the potential cost increases is exacerbated by what Staff identifies as a pressing need to review the Company's

Schedule 335 cost recovery structure from fixed non-residential charges to a volumetric charge. Staff has and will continue to pursue bill discount cost recovery discussions where we are working to ensure a more equitable distribution of cost recovery that minimizes the cost shifting effects of funding caps when programs grow.

In other words, Staff is not comfortable with moving forward with the changes to the bill discount program without better understanding the cost projections and recovery.

Q. Based on the concerns mentioned above, what does Staff request the Company do?

A. Staff requests that NW Natural perform cost projection analysis with the updated bill discount tiers and propose a change to the Company Schedule 335's cost-recovery in conjunction with this docket that is associated with the higher costs and a more equitable rate spread. Alternatively, Staff recommends the Company withdraw its proposed changes to the Bill Discount Program so that they may be addressed, in conjunction with cost recovery in a separate docket.

Q. Based on the discussion above, what is Staff's current recommendation?

A. Staff currently recommends that the Commission does not accept the proposed program changes until the Company provides further information regarding cost projections and additional information to informing the bill discount structure and cost recovery proposals moving forward. Staff welcomes and

encourages the Company to provide additional information in its Reply Testimony. Staff is particularly interested in cost estimates and the Company providing a proposal which updates the cost recovery structure to ensure equitable distribution of costs if and when the project continues to grow.

Staff wants to reiterate its appreciation for the Company's efforts to engage with stakeholders and propose changes to the Bill Discount Program based on its findings in Docket No. ADV 1390 and the LINA. Staff is however unable to recommend approval of the proposed changes to the Bill Discount Program.

Docket No: UG 490

Staff/1200
Lockwood/29

SUMMARY. STAFF RECOMMENDATIONS

Q. Please summarize your adjustments.

A. Staff proposes using the three-year average of the uncollectible rate between 2021 and 2023. NW Natural provided this average, an uncollectible rate of 0.182 percent, in the Company's testimony. Staff proposes applying this rate to the final agreed upon general revenues to calculate the appropriate amount for uncollectible accounts to be included in the Test Year. At this time, based on the Company's proposed general revenues in its Exhibit 201, Staff proposes a decrease to the Company's Test Year expense of approximately $2.8 million to eliminate some of the amount the Company forecasted for uncollectible accounts.

Staff recommends that the Commission does not accept the proposed Bill Discount program changes until the Company provides further information regarding cost projections and additional data informing the bill discount structure and cost recovery proposals moving forward. Staff welcomes and encourages the Company to provide additional information in its Reply Testimony.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 490
WITNESS: CHARLES LOCKWOOD

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1201

Witness Qualifications Statement

April 18, 2024

Docket No. UG 490

Staff/1201
Lockwood/1

WITNESS QUALIFICATIONS STATEMENT

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EDUCATION: University of Florida
Bachelor of Science in Environmental Science, 2019

University of Oregon
Juris Doctor, 2022
Concentrations in Green Business Law, Environmental and Natural Resources Law

EXPERIENCE: Oregon Public Utility Commission
Administrative Hearings Division Law Clerk, 2021-2022

Oregon Public Utility Commission
Utility Analyst, 2022 - Present

CASE: UG 490
WITNESS: CHARLES LOCKWOOD

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1202

Exhibits in Support
Of Opening Testimony

April 18, 2024

Staff/1202
Lockwood/1

Staff Workpaper titled UG 490 OT 1202 Workpaper is available in electronic spreadsheet format only

CASE: UG 490
WITNESS: CHARLES LOCKWOOD

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1203

Exhibits in Support
Of Opening Testimony

April 18, 2024

Staff/1203
Lockwood/1

Staff Workpaper titled UG 490 OT 1203 Workpaper is available in electronic spreadsheet format only

CASE: UG 490
WITNESS: CHARLES LOCKWOOD

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1204

Exhibits in Support
Of Opening Testimony

April 18, 2024

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 318

As it pertains to the Company's proposed bill discount program:

a. Please provide the number of residential customers in the Company's service territory on a monthly basis for 2022-2024.

b. How many customers does NW Natural estimate are able to qualify for each of the programs listed by the Company including OLGA, OLIEE, GAP, and LIHEAP? Please provide a breakdown by discount tier.

c. How many of IPCO's residential customers are currently receiving one of the programs? Additionally, how many customers are receiving two or more of the programs? Which are the most common programs to be combined?

d. Provide an estimate of the number of customers IPCO believes will be enrolled into the Bill Discount Program by the end of the calendar years 2024, 2025 and 2026, by discount tier. Please summarize the methodology used to arrive at these figures.

e. Provide a forecast of the total cost associated with the Bill Discount Program for the calendar years 2024, 2025, and 2026. Please provide a breakdown of cost categories. Please summarize the methodology used to arrive at these figures.

f. Please describe how the Company plans to monitor the kWh usage of Bill Discount Program participants for outliers. If there are no plans to monitor, please explain why.

g. Please provide the monthly average kwh usage for all residential customers for 2022-2024. Please provide a breakdown of average monthly kwh usage for LIHEAP customers for the same time period. Please provide a breakdown by dwelling type.

Response:

a. Oregon residential customer counts are as follows:

Count - 01/2022	629,034

Count - 02/2022	628,983
Count - 03/2022	629,689
Count - 04/2022	630,044
Count - 05/2022	630,161
Count - 06/2022	630,145
Count - 07/2022	629,809
Count - 08/2022	630,381
Count - 09/2022	630,787
Count - 10/2022	631,600
Count - 11/2022	632,897
Count - 12/2022	634,325
Count - 01/2023	635,376
Count - 02/2023	635,303
Count - 03/2023	635,926
Count - 04/2023	635,723
Count - 05/2023	635,653
Count - 06/2023	635,205
Count - 07/2023	634,459
Count - 08/2023	634,194
Count - 09/2023	634,533
Count - 10/2023	635,181
Count - 11/2023	636,072
Count - 12/2023	637,667

b. Please see responses to UG 490 OPUC DR 303a and b.

c. The Company interprets “IPCO” in the question as intended to read “NW Natural.” Please see UG 490 OPUC DR 318 Attachment 1. Based on the data in Attachment 1, it appears that the combination of OLGA and GAP is the most common.

d. The Company interprets “IPCO” in the question as intended to read “NW Natural.” Please see response to UG 490 OPUC DR 303b. Enrollee counts were not estimated by tier.

e. Please see response to UG 490 OPUC DR 303b. The estimated cost of the discounts for the residential bill discount program for 2024 as filed and approved in ADV 1562 was $10,718,994 excluding revenue-sensitive costs. This was comprised of an under-collected balance of $2,248,009.69 from 2023 and a forecast for 2024 of $7,930,984.25. The breakdown of the 2024 forecast by tier is as follows:

	Total cost for 2024 update
Disc tiers	
Level - 40%	2,074,988
Level - 25%	1,863,105
Level - 20%	1,636,610
Level - 15%	2,356,280
	7,930,984

f. The Company interprets "kWh" in the question as intended to read "therm." NW Natural does not currently monitor the therm usage of its residential bill discount program participants. During the Staff and stakeholder process of the Company's program in ADV 1390 during the spring and summer of 2022, stakeholders expressed concern about monitoring participants for increased usage, given the belief that an increase in usage may likely occur because participants could better afford to use more energy (e.g. customers would adjust their thermostats to a more comfortable level instead of at a colder level before the bill discount program). In addition, there may be many various reasons why some customers use more or less than others.

g. The Company interprets "kWh" in the question as intended to read "therm." Please see UG 490 OPUC DR 318 Attachment 2.

CASE: UG 490
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1300

Opening Testimony

April 18, 2024

Docket No: UG 490

Staff/1300
Moore/1

Q. Please state your name, occupation, and business address.

A. My name is Mitchell Moore. I am a Senior Utility Analyst employed in the Rates, Safety and Utility Performance Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/1301.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address Northwest Natural's revenue requirements for the following issues: Distribution Operations and Maintenance (O&M) expense; Materials and Supplies; Customer Accounts; Affiliated Interest; and Atmospheric Testing.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared Exhibit Staff/1302, consisting of 3 pages, and Confidential Exhibit Staff/1303, consisting of 6 pages.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Distribution O&M Expense....2
Issue 2. Materials and Supplies....6
Issue 3. Customer Accounts....8
Issue 4. Affiliated Interest....12
Issue 5. Atmospheric Testing....14

Docket No: UG 490

Staff/1300
Moore/2

ISSUE 1. DISTRIBUTION O&M EXPENSE

Q. Please describe O&M expense.

A. Distribution O&M refers to those expenses and activities recorded in FERC Accounts 870–894, and include operation, supervision and engineering, distribution load dispatching, compressor station and regulator station expenses, and customer installation expenses.

Q. What is the Company's proposal for distribution O&M expenses in this case?

A. Northwest Natural is proposing to include approximately $73.6 million in distribution O&M expense (FERC Accounts 870–894) in its Test Year expense. This represents an increase of 21 percent over the $60.8 million in the Base Year.[1] The majority of this—approximately $50.77 million—is labor expense. For non-labor expense, the Company proposes an increase in distribution O&M expense from $17.9 million in the Base Year to $22.8 million in the Test Year.[2] This represents an increase of $4.88 million, or more than 27.2 percent over the 2023 Base Year.

My testimony only addresses non-labor expense. Please see Staff Witness Stephanie Yamada's testimony in Staff 2000 addressing the labor portion of distribution O&M.

Q. How does NW Natural explain the increase in non-labor distribution O&M expense?

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1 See NW Natural/1401-1402, Davilla/1.
2 See Exhibit Staff/1302, Moore/1-2, Company response to Staff DR No. 58.

A. In its opening testimony, the Company points to two specific drivers for increased costs: Contracted locating services expense is projected to increase by $2.9 million and contracted survey services expense is projected to increase by $0.92 million in the Test Year.[3] The Company states that it entered a new agreement with its contract locating company, Health Consultants, which calls for a three percent annual increase in rates. In addition, the Company explains that the number of customers calling to request locating services is projected to increase 1.5 percent annually. The Company also amended its contract with Health Consultants for survey and inspection services, with a rate that is also expected to increase by three percent annually.

Additionally, the Company escalates its general non-labor expense using the West Region Urban CPI.

Q. Please describe your review and analysis of NW Natural's distribution O&M expense.

A. Staff first reviewed the distribution O&M expenses for the historical calendar years of 2021, 2022, and 2023. This review included looking at trends, transactional details, and adjustments proposed by NW Natural.

Staff initially looked at the annual increase in non-labor distribution O&M expenses for the past three years to determine whether the proposed increase in the Test Year is consistent with historical expenses. Staff also reviewed transaction details from the Base Year expense (2023) to ensure expenditures are justifiable for normal utility operations.

[3] See NW Natural/1400, Davilla/11-12.

Staff also reviewed the Company's responses to Staff Data Requests that focused on investigating the Company's new locating and surveying contracts with Health Services.

Q. What does Staff conclude from its review?

A. A trend analysis suggests that the proposed Test Year expenses are out of line with expense trends over previous years. Non-labor Distribution O&M expense has seen significant increases since 2021—a 10.5 percent increase in 2022, and a 14.8 percent increase in 2023 over previous years. The increase in the Test Year expense over CPI inflation is almost entirely a result of the increase in NW Natural's contract locating and survey rates. With the new contract, the cost per locating unit increased 58.4 percent from the Base Year to the Test Year over the previous contract rate. The after-hours locate rate has increased 81.3 percent over the previous contract rate.

Q. Why have NW Natural's locate and survey costs increased so much?

A. NW Natural has used Health Consultants for survey services since at least 2021. NW Natural amended a previous contract for survey services with Health Consultants, and the amended rates for survey services were about 18 to 35 percent higher than the previous contract. As noted above, these rates increased an additional three percent with the most newly executed contract.

The locating contract for most of the Base Year, and several years prior, was with Locating Inc. NW Natural signed a new contract transferring its locating services to Health Consultants effective September 1, 2023.[4]

[4] See Confidential Exhibit NW Natural/1406, Davilla/3.

Q. Did NW Natural conduct a competitive bid process for the survey and locating contracts?

A. Yes. NW Natural conducted a request for procurement (RFP) in late 2022 that sought bids for a single contractor to provide all survey and locating services. In response to a Staff Data Request, NW Natural represents that Health Consultants was selected as the vendor and had the "lowest scaled pricing" and provided excellent quality service…and was the "clear overall winner" for the awarded contract.

Q. Does Staff recommend an adjustment for non-labor distribution O&M?

A. Yes. At this time, Staff does not believe the Company has substantiated the reasonableness of the extreme increase in the cost of survey and locate rates. Therefore, Staff recommends an adjustment that reflects the three-year historical average of non-labor O&M costs, escalated for inflation at inflation rates recommended by Staff in Staff/800, which results in an adjustment of ($6.2 million) to non-labor O&M expense.

Docket No: UG 490

Staff/1300
Moore/6

ISSUE 2. NON-FUEL MATERIALS AND SUPPLIES

Q. Please summarize NW Natural's proposal for non-fuel materials and supplies.

A. Northwest Natural proposes an average Test Year balance for materials and supplies in rate base of $25,496,000 at a system level. The Oregon-allocated forecast Test Year rate base amount is $21,810,000.[5] This represents a 13.64 percent increase over the 2023 Base Year.

Q. Please summarize the Commission's historical treatment of non-fuel materials and supplies in rate base.

A. The Commission typically authorizes utilities to include an allowance for non-fuel materials and supplies in rate base.

Q. Please describe Staff's analysis of this issue.

A. Staff reviewed historical balances for the years 2021–2023 and compared the average of monthly average balances for each year with the year-end forecast for 2024. Staff believes that using an average of monthly averages balance for rate-based items provides an accurate picture of yearly rate-based components that earn a rate of return.

Using an average of monthly average balances for 2021, 2022, and 2023, escalated for inflation of 2.7 percent in 2024 and 2.0 for 2025 results in a forecast Test Year balance of $17,783,000.[6]

Q. Does Staff propose an adjustment?

---

5 See Staff/1302, Moore/3, Company response to Staff DR No. 84.
6 See Staff/1304, Moore/Workpaper.

A. Yes. Staff believes NW Natural has overestimated the non-fuel material and supplies by $4 million), and therefore recommends a downward adjustment to rate base by this amount.

Docket No: UG 490

Staff/1300
Moore/8

ISSUE 3. CUSTOMER ACCOUNTS

Q. Please describe Non-labor Customer Accounts expense.

A. Non-labor Customer Accounts expense addressed in my testimony is recorded in FERC Account Nos. 901–903.[7] This includes expense for activities such as supervision, meter reading, and customer records and collection expense.

Q. Please describe NW Natural's proposal regarding non-labor Customer Accounts expense.

A. NW Natural proposes a Test Year forecast of $12.26 million at a system level, and $10.8 million for Oregon-allocated expense. This represents a 20.5 percent increase over the Oregon-allocated Base Year expense of $8.95 million. The majority of the expense, and the increase, is in FERC Account No. 903 – Customer Records and Collection expense.

Q. What reasons does the Company provide to explain the increase?

A. NW Natural explains in its opening testimony it expected an increase in expense due to an expected amendment to its contract with Paymentus, which provides electronic bill payment services. This amendment was in fact executed in late December 2023. NW Natural explains that an increase in costs charged by Paymentus, combined with an increase in the number of customers that prefer to pay their bill by bankcard or other electronic methods, results in a total Oregon-allocated expense increase in the Test Year of $1.29 million over the 2023 Base Year.[8]

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[7] Staff Witness Charles Lockwood addresses FERC Account No. 904 – Uncollectible Accounts in Staff/1200.

[8] See NW Natural/1400, Davilla/11.

Q. How does Staff view NW Natural's explanation for the increase?

A. Staff is concerned about the escalating cost of offering customers fee-free electronic payment options. The projected increase from the Base year to the Test Year is 42.8 percent from the Base Year to the Test Year; from $3,846,000 in 2023 to $5,490,211 in 2025.[9] In response to a Staff data request, the Company provided the amendment to the Paymentus contract that was made effective in December of 2023.[10] In comparing the fees in the amended contract with the fees outlined in the pre-existing contract, Staff finds **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

[9] See Exhibit Staff/1302, Moore/4-5 – Company response to Staff Data Request No. 404.
[10] See Confidential Exhibit Staff/1303, Moore/1-6 – Confidential response to Staff Data Request No. 404 attachment 1.

In previous cases, Staff has recognized that it is reasonable to make payment options available to customers to ensure customers have convenient methods to pay their bills. Further, given the importance of accessibility to payment options, Staff has supported spreading the costs of these payment options to all customers rather than requiring that the individual customers that use these options pay for them at the time of use. However, this does not mean it is reasonable to spread costs of even the most expensive methods of payment to all customers.

Staff's view is that the Company has a responsibility to communicate to its customers the costs of the various methods of payment, and if customers choose options that are less reasonably priced, the costs should not be spread to other customers. By having all customers absorb the costs of payment processing, without any transparency to what those costs are, and without absorbing—or avoiding—those costs individually, customers are left without any means to mitigate the impact of increasing costs.

Q. How does Staff forecast NW Natural's Test Year expense?

A. In this case, Staff believes it is reasonable to use a three-year historical average and then escalate the average with the expected CPI inflation index to arrive at a forecast Test Year. For customer accounts, the Test Year forecast should be $8.7 million. This forecast methodology accounts for an increase in payment processing costs and incentivizes the Company to encourage lower-cost payment options, while still allowing for more expensive options such as Amazon Pay, PayPal, and Venmo to be available to customers. Staff

is not convinced that the more expensive options are a necessary benefit to customers, but are more geared toward Company image enhancement, which benefits shareholders.

Q. Does Staff recommend an adjustment?

A. Yes. Staff recommends the Company's Test Year forecast expense for Customer Accounts be adjusted by ($2.1 million).

Docket No: UG 490

Staff/1300
Moore/12

ISSUE 4. AFFILIATED INTEREST

Q. Please explain the Commission's historical treatment of cost allocation among affiliates.

A. The Commission's historical treatment of cost allocation among affiliates is pursuant to OAR 860-027-0048 (Allocation of Costs by an Energy Utility), which addresses the allocation of costs between an energy utility and its affiliates, outlining how transactions should be recorded. OAR 860-027-0048 also states that an energy utility must keep a current Cost Allocation Manual (CAM), with detailed methodology on how costs are allocated between affiliates on file with the Commission. The rule also requires that the Allocation Manual shall be "filed yearly as an appendix to the Affiliated Interest Report required under OAR 860-027-0100."

Q. How does NWN generally allocate costs among its affiliates?

A. According to NWN's CAM, "the approach to allocating costs is to directly assign costs when applicable and to allocate costs based on the primary cost driver of the common cost, or relevant proxy, and to ensure that unauthorized subsidization of unregulated activities by regulated activities, and vice versa, does not occur." The CAM also states that "goods or services provided by the utility to an affiliate are provided at the higher of cost or market price," which is in accordance with OAR 860-027-0048. Typical affiliated transactions that occur between NWN and its affiliates include:

- Direct charges of NWN's payroll and administrative expense for affiliate use of NWN's staff;

- Payments between NWN and affiliates for tax expense or benefits;
- Annual allocation of indirect charges per the CAM;
- Direct charges for office space used by NWN's non-regulated affiliates;
- Vendor payments made by NWN on behalf of affiliates; and
- Equity distributions/contributions and dividends between NWN and affiliates.

Q. Please summarize Staff's review of the Company's Affiliate Interest transactions.

A. Staff requested transactional level detail to review cost allocation between the Company and its affiliates and non-regulated entities. Staff reviewed the Company's 2020 affiliated interest report, 43 including its MSA and CAM as well as transactions between NWN and its affiliates. NWN did not propose any changes to its CAM in this filing. Staff's review focused on ensuring allocation factors are calculated and applied correctly and in adherence with cost allocation principles outlined in NARUC's cost allocation manual and referenced above.

Q. Does Staff propose an adjustment related to this issue?

A. No. Staff proposes no adjustment related to this issue.

Docket No: UG 490

Staff/1300
Moore/14

ISSUE 5. ATMOSPHERIC TESTING

Q. Please describe NW Natural's atmospheric testing program.

A. Atmospheric Testing expenses include the cost of compliance with a federal safety mandate to inspect all portions of natural gas pipelines in contact with air for signs of corrosion. The Company uses a third-party vendor to conduct atmospheric surveys related to leakage and corrosion, and each section of pipe is inspected every three years in compliance with federal regulations.

Q. Please summarize the Company's proposal regarding atmospheric testing.

A. NW Natural proposes to include $2.4 million in Oregon-allocated atmospheric testing activities for the Test Year in FERC Account Nos. 856 (Mains Expense), 874 (Mains and Service Expense), and 892 (Maintenance of Service). This represents a decrease of $2.6 million from the Base Year, in which $4.66 million was spent.

Q. Please describe Staff's review of this issue.

A. Staff reviews the proposed forecast expense for reasonableness, and to assure compliance with federal regulations. Staff issued several data requests to determine the historical spending in this area, as well as compared the Company's historical expense in prior rate cases. The Company's spending varies from year to year, depending on the inspection cycle. The Company's forecast Test Year expense is the lowest it has been since 2019. The Company also represents that it is not proposing any new or different treatment from current or past practice.

Q. What does Staff conclude from its review?

A. Staff concludes the Company's projection is reasonable, and therefore Staff has no adjustment to recommend on this issue.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 490
WITNESS: MITCH MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1301

Witness Qualifications Statement

April 18, 2024

Docket No. UG 490

Staff/1301
Moore/1

WITNESS QUALIFICATIONS STATEMENT

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EDUCATION: Bachelor of Arts, Journalism and Political Science
University of Hawaii at Manoa (1992)

EXPERIENCE: I have been employed by the Public Utility Commission of Oregon since 2009, with my current position being a Senior Utility Analyst in the utility program's Energy Rates, Finance and Audit division. I have provided expert witness testimony on a number of general rate case dockets, including: UE 294, UE 319, UE 335, UG 288, UG 305, UG 325, UG 344, UG 347, UG 366, and UG 388.

My prior position at the Commission was as a Senior Telecommunications Analyst, where my assignments included reviewing carrier interconnection agreements, wholesale service quality, and resolution of carrier-to-carrier complaints.

Prior to my utility regulatory career, I worked with AT&T as a loop electronics coordinator, designing and implementing high-speed broadband and fiber optic services in Los Angeles. I have also worked as an outside plant design engineer with Qwest Corporation, and I spent several years as a newspaper reporter with the Honolulu Star-Bulletin.

CASE: UG 490
WITNESS: MITCH MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1302

Exhibits in Support
Of Opening Testimony

April 18, 2024

Data Request 58
FERC O&M Costs - Non Labor Costs
Attachment 2 58(b)
Test Year

	Test Year 11/1/2024 - 10/31/2025						
		Allocations					
	a)	b)	c)	d)	e)	f)	g)
Account	Account Total b+c	Non-Utility	Total Regulated Utility Service	Oregon Alloc. Factor	Oregon Alloc./Share	Oregon Situs	Total included in Filed Rate Case e+f
816	677,828	-	677,828	90%	608,545	-	608,545
818	309,948	-	309,948	89%	275,885	-	275,885
819	42,722	-	42,722	89%	38,027	-	38,027
820	1,338,125	-	1,338,125	89%	1,191,101	-	1,191,101
821	-	-	-	0%	-	-	-
832	791,624	-	791,624	89%	704,625	-	704,625
834	1,667,248	-	1,667,248	89%	1,484,018	-	1,484,018
840	17,001	-	17,001	89%	15,133	-	15,133
844	791,901	-	791,901	89%	704,871	-	704,871
845	(166,352)	-	(166,352)	89%	(148,069)	-	(148,069)
847	736,451	-	736,451	89%	655,515	-	655,515
856	3,471,243	-	3,471,243	99%	3,428,586	-	3,428,586
863	6,235	-	6,235	99%	6,158	-	6,158
870	514,201	-	514,201	92%	474,365	-	474,365
874	16,897,615	-	16,897,615	89%	14,979,916	-	14,979,916
875	129,713	-	129,713	91%	117,893	-	117,893
877	312,319	-	312,319	91%	283,525	-	283,525
878	690,818	-	690,818	88%	607,160	-	607,160
879	3,241,250	-	3,241,250	88%	2,848,719	-	2,848,719
880	146,884	-	146,884	88%	129,755	-	129,755
881	291,272	-	291,272	87%	251,980	-	251,980
885	290,607	-	290,607	92%	266,093	-	266,093
887	1,742,004	-	1,742,004	92%	1,606,235	-	1,606,235
889	597,723	-	597,723	91%	542,832	-	542,832
891	95,853	-	95,853	91%	87,492	-	87,492
892	239,870	-	239,870	88%	210,833	-	210,833
893	488,587	-	488,587	88%	430,681	-	430,681
894	1,869	-	1,869	88%	1,643	-	1,643
901	83,928	-	83,928	88%	73,764	-	73,764
902	42,839	-	42,839	88%	37,652	-	37,652
903	12,132,693	-	12,132,693	88%	10,678,473	-	10,678,473
904	The total for FERC 904 is removed from the O&M balance as it is reported elsewhere for this period.						
907	-	-	-	0%	-	-	-
908	45,169	-	45,169	88%	39,922	-	39,922
909	1,931,093	-	1,931,093	88%	1,697,238	-	1,697,238
910	5,024	-	5,024	88%	4,407	-	4,407
911	6,493	-	6,493	88%	5,706	-	5,706
912	477,137	-	477,137	88%	420,171	-	420,171
913	-	-	-	0%	-	-	-
916	-	-	-	0%	-	-	-
921	55,691,773	-	55,691,773	88%	49,080,025	-	49,080,025
922	(25,374,489)	-	(25,374,489)	88%	(22,403,377)	-	(22,403,377)
924	6,325,360	-	6,325,360	88%	5,589,088	-	5,589,088
925	198,213	-	198,213	88%	175,141	-	175,141
926	15,214,830	-	15,214,830	94%	14,320,189	-	14,320,189
928	-	-	-	0%	-	-	-
930	5,414,275	-	5,414,275	92%	4,977,707	-	4,977,707
931	11,024,949	-	11,024,949	88%	9,742,139	-	9,742,139
932	4,361,563	-	4,361,563	90%	3,924,398	-	3,924,398
TOTAL O&M Expense (Less Acct 904 Uncollectible)	122,945,408	-	122,945,408		110,166,162	-	110,166,162
PLUS $5mm Environmental Recovery Expense	5,000,000	-	5,000,000		5,000,000	-	5,000,000
TOTAL O&M Expense	127,945,408	-	127,945,408		115,166,162	-	115,166,162

Data Request 58
FERC O&M Costs
Attachment 2 58(b)
Base Year

	Base Year Ending December 31, 2023						
	Actuals through 9/30 with 10/1-12/31 Forecast						
		Allocations					
	l)	m)	n)	p)	q)	r)	s)
Account	Account Total m+n	Non-Utility	Total Regulated Utility Service	Oregon Alloc. Factor	Oregon Alloc./Share	Oregon Situs	Total included in Filed Rate Case q+r
816	639,239	-	639,239	90%	573,900	-	573,900
818	292,297	-	292,297	89%	260,174	-	260,174
819	40,618	-	40,618	0%	36,154	-	36,154
820	1,260,118	-	1,260,118	89%	1,121,666	-	1,121,666
821	-	-	-	#DIV/0!	-	-	-
832	156,520	-	156,520	89%	139,318	-	139,318
834	1,571,706	-	1,571,706	89%	1,398,975	-	1,398,975
840	16,022	-	16,022	89%	14,261	-	14,261
844	745,463	-	745,463	89%	663,536	-	663,536
845	(156,047)	-	(156,047)	89%	(138,898)	-	(138,898)
847	692,494	-	692,494	89%	616,389	-	616,389
856	3,270,366	-	3,270,366	99%	3,230,178	-	3,230,178
863	5,849	-	5,849	99%	5,777	-	5,777
870	485,335	-	485,335	92%	447,734	-	447,734
874	11,903,092	-	11,903,092	89%	10,552,218	-	10,552,218
875	122,388	-	122,388	91%	111,235	-	111,235
877	295,121	-	295,121	91%	267,912	-	267,912
878	650,687	-	650,687	88%	571,889	-	571,889
879	3,057,309	-	3,057,309	88%	2,687,055	-	2,687,055
880	139,429	-	139,429	88%	123,169	-	123,169
881	274,341	-	274,341	87%	237,333	-	237,333
885	273,955	-	273,955	92%	250,846	-	250,846
887	1,640,153	-	1,640,153	92%	1,512,322	-	1,512,322
889	563,227	-	563,227	91%	511,504	-	511,504
891	89,537	-	89,537	91%	81,727	-	81,727
892	226,802	-	226,802	88%	199,348	-	199,348
893	461,231	-	461,231	88%	406,567	-	406,567
894	1,755	-	1,755	88%	1,542	-	1,542
901	79,365	-	79,365	88%	69,754	-	69,754
902	40,266	-	40,266	88%	35,390	-	35,390
903	10,053,657	-	10,053,657	88%	8,848,630	-	8,848,630
904	The total for FERC 904 is removed from the O&M balance as it is reported elsewhere for this period.						
907	-	-	-	0%	-	-	-
908	43,437	-	43,437	88%	38,392	-	38,392
909	1,290,342	-	1,290,342	88%	1,134,082	-	1,134,082
910	4,753	-	4,753	88%	4,169	-	4,169
911	6,118	-	6,118	88%	5,377	-	5,377
912	449,737	-	449,737	88%	396,043	-	396,043
913	621,027	-	621,027	88%	545,821	-	545,821
916	-	-	-	0%	-	-	-
921	46,498,211	-	46,498,211	88%	40,977,926	-	40,977,926
922	(23,010,226)	-	(23,010,226)	88%	(20,315,946)	-	(20,315,946)
924	5,104,380	-	5,104,380	88%	4,510,230	-	4,510,230
925	196,151	-	196,151	88%	173,319	-	173,319
926	6,390,917	-	6,390,917	101%	6,472,829	-	6,472,829
928	-	-	-	0%	-	-	-
930	4,963,081	-	4,963,081	92%	4,560,973	-	4,560,973
931	10,565,934	-	10,565,934	88%	9,336,533	-	9,336,533
932	4,110,556	-	4,110,556	90%	3,698,550	-	3,698,550
TOTAL O&M Expense (Less Acct 904 Uncollectible)	96,126,713	-	96,126,713		86,375,906	-	86,375,906
PLUS $5mm Environmental Recovery Expense	5,000,000	-	5,000,000		5,000,000	-	5,000,000
TOTAL O&M Expense	101,126,713	-	101,126,713		91,375,906	-	91,375,906

			MAT & SUPPLIES-GEN	INVEN RESERVE - UTIL	MAT & SUPPLIES-ODORA	INVENTORY-OFFICE SUP	MAT & SUPP-DIESEL AU	MAT & SUPP-UNLEADED	Total	
			NWN/154001		NWN/154040	NWN/154050	NWN/154071	NWN/154073		
		Previous GL	154001	154038	154040	154050	154071	154073		
		New Horizon GL	127220	127235	127245	127250	127255	127260		
January	2023	Actual	22,008,547	-	164,683	-	33,635	14,690	22,221,553	Base Year
February	2023	Actual	21,768,759	-	248,965	-	14,139	(30,759)	22,001,104	Base Year
March	2023	Actual	22,360,396	-	210,118	-	(8,527)	(78,574)	22,483,414	Base Year
April	2023	Actual	22,427,159	-	185,251	-	39,711	74,614	22,726,734	Base Year
May	2023	Actual	22,295,052	-	171,067	-	38,646	53,429	22,558,193	Base Year
June	2023	Actual	22,315,229	-	158,519	-	24,826	126,686	22,625,260	Base Year
July	2023	Actual	22,888,445	-	276,474	-	59,016	156,823	23,380,758	Base Year
August	2023	Actual	23,042,840	-	265,040	-	12,790	116,718	23,437,388	Base Year
September	2023	Actual	23,479,384	-	252,606	-	78,607	153,684	23,964,281	Base Year
October	2023	Forecast	22,261,458		220,424		20,970	48,992	22,551,844	Base Year
November	2023	Forecast	22,425,849		221,252		20,605	47,703	22,715,409	Base Year
December	2023	Forecast	22,590,240		222,081		20,239	46,414	22,878,974	Base Year
January	2024	Forecast	22,754,631		222,910		19,874	45,125	23,042,540	
February	2024	Forecast	22,919,022		223,738		19,509	43,836	23,206,105	
March	2024	Forecast	23,083,413		224,567		19,144	42,547	23,369,671	
April	2024	Forecast	23,247,804		225,396		18,778	41,258	23,533,236	
May	2024	Forecast	23,412,195		226,224		18,413	39,969	23,696,802	
June	2024	Forecast	23,576,587		227,053		18,048	38,680	23,860,367	
July	2024	Forecast	23,740,978		227,882		17,683	37,391	24,023,933	
August	2024	Forecast	23,905,369		228,710		17,317	36,102	24,187,498	
September	2024	Forecast	24,069,760		229,539		16,952	34,813	24,351,064	
October	2024	Forecast	24,234,151		230,368		16,587	33,524	24,514,629	
November	2024	Forecast	24,398,542		231,196		16,221	32,235	24,678,195	Test Year
December	2024	Forecast	24,562,933		232,025		15,856	30,946	24,841,760	Test Year
January	2025	Forecast	24,727,324		232,854		15,491	29,657	25,005,325	Test Year
February	2025	Forecast	24,891,715		233,682		15,126	28,368	25,168,891	Test Year
March	2025	Forecast	25,056,107		234,511		14,760	27,079	25,332,456	Test Year
April	2025	Forecast	25,220,498		235,340		14,395	25,790	25,496,022	Test Year
May	2025	Forecast	25,384,889		236,168		14,030	24,501	25,659,587	Test Year
June	2025	Forecast	25,549,280		236,997		13,664	23,212	25,823,153	Test Year
July	2025	Forecast	25,713,671		237,826		13,299	21,923	25,986,718	Test Year
August	2025	Forecast	25,878,062		238,654		12,934	20,633	26,150,284	Test Year
September	2025	Forecast	26,042,453		239,483		12,569	19,344	26,313,849	Test Year
October	2025	Forecast	26,206,844		240,311		12,203	18,055	26,477,415	Test Year
November	2025	Forecast	26,371,236		241,140		11,838	16,766	26,640,980	
December	2025	Forecast	26,535,627		241,969		11,473	15,477	26,804,546	

Base Year System (000)	22,740
Test Year System (000)	25,496

Rate Base Elements	Base Year	Test Year
System	**22,740**	**25,496**
Allocation Factor (Distribution Plant)	85.5%	85.5%
Oregon	**19,452**	**21,810**

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 404

Referencing NW Natural/1400, Davilla/pg. 11, Contracted Customer Payment Processing Fees (FERC 903), and NW Natural/1405, Davilla/pgs 1-14:

a. When does the current contract expire?

b. What is the Oregon-allocated total actual expense for this contract for the years 2020-2023?

c. What is the Oregon-allocated total forecast expense for this contract for 2024?

d. What is the Oregon-allocated Test Year forecast for this expense?

e. Please explain and demonstrate the basis for the Oregon-allocated forecast increase to this contract in the Test Year.

f. When (month/year) does the Company expect to have an amended contract in place?

g. What efforts has the Company made to ensure that costs for bankcard services are competitive? Please describe and demonstrate.

Response:

A. The testimony states that the Company "expects to sign a contract amendment and extension in the near term." NW Natural/1400, Davilla/Page 11, Lines 11-12. An extended contract was entered into on December 27, 2023, and is provided as Confidential UG 490 OPUC DR 404 Attachment 1. The current contract expires May 4, 2027.

B. The Oregon-allocated total actual expense for this contract for the years 2020-2023 are as follows:

Period	System Wide	Oregon Allocation
2020 Oct to Dec	$633,000	$557,000
2021	$3,460,000	$3,045,000

UG 490 OPUC DR 404
NWN Response Page 2 of 2

2022	$3,930,000	$3,459,000
2023	$4,370,000	$3,846,000

C. The Oregon-allocated total forecast expense for this contract for 2024 is as follows:

Period	System Wide	Oregon Allocation
2024	$5,339,332	$4,699,146

D. The Oregon-allocated Test Year forecast for this expense is $5,490,211 ($6,237,881 System).

E. Please see NW Natural/1400, Davilla/Page 11, Lines 12-16. Primary factors for the Oregon-allocated forecast increase to this contract in the Test Year are:

   a. Customers have expressed a significant preference for bankcard payments.
   b. Migration of customers from 1.) paper payment methods (mailing a check) and 2.) customer specific bank bill pay methods to 3.) autopay methods via ach or bankcard or 4.) one time ach and bankcard payments.
   c. Test Year transactions are expected to grow at a 10 percent compound annual growth rate from the Base Year to the Test Year.

F. Please see the response to subpart A.

G. Before extending the current contract, competitive pricing was received from two other processors that provide bankcard processing services. The pricing of each of those other two processors was greater than our current and selected processor. Vendor A's proposal was approximately 39% more expensive and Vendor B's proposal was approximately 47% more expensive. Please see Confidential UG 490 OPUC DR 404 Attachment 2 for a comparison of those proposals and the Paymentus extended contract.

CASE: UG 490
WITNESS: MITCH MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1303

CONFIDENTIAL Exhibit in Support Of Opening Testimony

April 18, 2024

CASE: UG 1400
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1400

OPENING TESTIMONY

Depreciation Expense, Amortization Expense, Depreciate Reserve, Amortization Reserve, and Allowance for Funds Used During Construction

April 18, 2024

Docket No: UG 490 Staff/1400
Peng/1

Q. Please state your name, occupation, and business address.

A. My name is Ming Peng. I am a Senior Economist employed in the Rates, Safety and Utility Performance Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/1401.

Q. What is the purpose of your testimony?

A. I discuss my analysis of the depreciation expense and accumulated depreciation, or depreciation reserve, and portions of Northwest Natural's (NWN or Company) revenue requirement for this rate case as documented by the Company witnesses, NW Natural/100 Palfreyman-Kravitz, and NW Natural/1600 Spanos. I also discuss my review of the Allowance for Funds Used During Construction (AFUDC) portion of revenue requirement for this rate case.

Q. Did you prepare any exhibits for this docket?

A. Yes. In addition to my witness qualifications statement, I prepared Exhibit Staff/1402, NWN Responses to Staff Data Requests.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Summary of Findings and Recommendations 3
Issue 1. Depreciation Expense 5
Issue 2. Amortization Expense 10
Issue 3. Depreciation Reserve 11
Issue 4. Amortization Reserve 12

Docket No: UG 490

Staff/1400
Peng/2

Issue 5. Allowance for Funds Used During Construction (AFUDC)..... 13

Docket No: UG 490

Staff/1400
Peng/3

SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. Please summarize your findings and recommendations.

A. Please note that I may revise my recommendations based on testimony filed by other participants in this rate case.

1. Depreciation Expenses: I do not yet have a recommendation regarding depreciation expenses because I am waiting for the Oregon PUC to authorize depreciation rates before deciding if the adjustment is needed. In the UG 490 general rate case, NWN used the updated depreciation rates proposed in a new depreciation study the company filed with the Commission in January 2024, docketed as UM 2312. The procedural schedule UM 2312 includes settlement conferences in June 2024 and in the event settlement is not reached, a hearing in July 2024, so a Commission decision on depreciation rates should be issued no later than October 2024. I am currently reviewing the UM 2312 depreciation study. Once the depreciation case is settled and the Commission issues an order to authorize the updated depreciation rates, then Staff can calculate depreciation expenses for the UG 490 revenue requirement.
2. Amortization Expenses: I do not yet have a proposed adjustment because I need to wait to see if NWN's amortization expense calculation complies with Commission-authorized rates in UM 2312. In this depreciation schedule, an amortization expense is the expense for the intangible plants, which include software, cloud-based

software, and the customer information system.

3. Depreciation Reserve (Accumulated depreciation reserve): Staff has proposed no adjustment to depreciation reserves in UG 490, because the depreciation rates are still under review, and if depreciation expense is changed, the depreciation reserve will be changed accordingly.

4. Amortization Reserve (Accumulated amortization reserve): Staff has proposed no adjustment to depreciation reserves in UG 490, because the depreciation/amortization rates are under review, and if amortization expense is changed, the amortization reserve will be changed accordingly.

5. I made an adjustment to the Company's proposed AFUDC by pulling out of rate base the portion of AFUDC that exceeds the authorized rate is of 0.63 and putting it into "Excess AFUDC Regulatory Liability" on the utility's balance sheet. The Company may seek to recover the excess AFUDC through rate adjustments, subject to regulatory approval.

Docket No: UG 490

Staff/1400
Peng/5

ISSUE 1. DEPRECIATION EXPENSE

Q. What is depreciation?

A. "Depreciation" is defined by the National Association of Regulatory Utility Commissioners (NARUC) in relevant part as follows:

> As applied to the depreciable plant of utilities, the term depreciation means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes that are known to be in current operation, against which the company is not protected by insurance, and the effect of which can be forecast with reasonable accuracy. Among the causes to be considered are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and the requirement of public authorities.[1]

Q. Why is depreciation important in a revenue requirement?

A. NARUC states that:

> Depreciation has a profound effect on the revenue requirement of a utility, and for many utilities, depreciation expense represents a large percentage of total operating expenses. In addition, deferred income taxes, rate base, and cost of capital are all affected by the depreciation practices of a utility.[2]

1. From a valuation perspective, depreciation is the loss in service value not restored by current maintenance.

2. From an accounting perspective, depreciation is the allocation of the cost of fixed assets less net salvage to accounting periods, which is a capital recovery concept.

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1 NARUC, Public Utility Depreciation Practices, p.318 (1996).
2 NARUC, Public Utility Depreciation Practices, p.195 (1996).

3. From a ratemaking perspective, both the valuation (rate base) and accounting (capital recovery) concepts of deprecation are important.

Q. Do Oregon statutes address utility depreciation rates?

A. Yes. ORS 757.140(1) states:

> Every public utility shall carry a proper and adequate depreciation account. the public utility commission shall ascertain and determine the proper and adequate rates of depreciation of the several classes of property of each public utility. the rates shall be such as will provide the amounts required over and above the expenses of maintenance, to keep such property in a state of efficiency corresponding to the progress of the industry. Each public utility shall conform its depreciation accounts to the rates so ascertained and determined by the commission. The commission may make changes in such rates of depreciation from time to time as the commission may find to be necessary.

Q. How are utility property depreciation rates determined?

A. To develop depreciation rates, it is necessary to estimate: (1) the combination of survivor curve[3]-service life (Curve-Life) of utility property, and (2) the net salvage[4] (Gross Salvage – Cost of Removal) ratio. Based on these two fundamental depreciation parameters (and other required elements, such as asset value, asset remaining life, and depreciation method) the depreciation rates are derived.

Q. What is the Commission's historical treatment of a depreciation calculation in a revenue requirement?

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[3] "Survivor curves" are curves that show the number of units or cost of a given group that is surviving in service at given ages. The survivor curves were developed by the Engineering Research Institute of Iowa State University. These curves are frequently referred to as "Iowa Curves."

[4] Net Salvage. The gross salvage of the property retired less the cost of removal. This will be negative if the cost of removal exceeds the gross salvage.

A. A utility should use the Commission-authorized depreciation parameters and rates to calculate the depreciation and amortization expense and reserve. A Company's Depreciation Expense is determined by (OPUC-Authorized Depreciation Rate) x (Oregon net plant in service) x (allocation factor).

Q. Why do we need to use authorized depreciation rate results for the revenue requirement calculation?

A. To compute the revenue requirement (RR), which is measured by cost-of-service, a basic formula is followed:

RR = O&M Expense + "Depreciation" + Taxes + Return% x Rate Base

- Depreciation expense is calculated by (Depreciation rate) x (plant in service) x (allocation factor, if any).
- Depreciation expense represents a large percentage of total operating expenses. The deferred income taxes, rate base, and cost of capital are all affected by the depreciation. Therefore, to calculate depreciation expense and reserve, we must use the Commission-authorized depreciation parameters to reflect the true cost in the revenue requirement.

Q. Has NWN explained the key drivers for the increase in the company's revenue requirement?

A. Yes. In UG 490, NWN explains that the results of the depreciation study are one of the key drivers for the increase requested in the Company's revenue requirement. Applying the depreciation rates from the depreciation study to

Test Year plant balances results in an increase to depreciation expense of $62.4 million, and revenue requirement increase of 16.62 percent.

Q. Are there any important issues that we need to consider in the UG 490 GRC and UM 2312 depreciation filings?

A. Yes. In NW Natural/100 Palfreyman-Kravitz/Page 19-23, the witnesses stated, "In the Company's most recently filed depreciation study (UM 2214), the Commission requested that NW Natural address the issue of accelerated depreciation when it files its next depreciation study."

In Order No. 22-322 (at page 3), the Commission stated the following:

> In adopting this stipulation, we are mindful that prior to the company's next depreciation study, to be filed no later than December 31, 2027, NW Natural, Staff, and stakeholders will be engaged in significant work towards the company reducing emissions in response to the Oregon Department of Environmental Quality's Climate Protection Program or other policy and regulatory directives. We anticipate that parties may seek to evaluate accelerated depreciation or other adjustments to asset depreciation schedules as one tool to mitigate uncertainty about decarbonization pathways and manage potential future risks to customers. We ask that the company include in its next depreciation filing testimony addressing its consideration of this approach.

NW Natural/100 Palfreyman-Kravitz/Page 22 further explained:

> For this reason, the Company has updated its depreciation study, which will require a higher revenue requirement. If we can reset these rates to reflect the actual results of our depreciation study, we can then begin to discuss the justifications for, and impacts of, accelerated depreciation. For example, certain investments in our system are relatively short-lived, especially in the cloud-based IT&S environment. This is part of the changing nature of the utility industry, which is driving more frequent rate cases and higher depreciation expense. On the other hand, service and main lines are longer lived assets, have large plant balances, and any policy driven change to these lives

would cause customers' bills to rise.

However, NWN clarified in testimony that is it not proposing accelerated depreciation in this case:

> Given the near-term rate pressure associated with NW Natural's proposal to increase its depreciation expense to reflect the useful life of its assets, we do not believe that further increases to depreciation expense are appropriate to mitigate the potential future risks of certain decarbonization pathways that the Company may pursue.[5]

Q. What is Staff's understanding of accelerated depreciation on gas pipeline assets for decarbonization in this filing?

A. The accelerated depreciation may provide financial benefits for gas pipeline companies; however, it is not a direct way to reduce CO_2 emissions associated with natural gas transportation and consumption. This is because NWN primarily transports and stores natural gas, so using an accelerated depreciation alone would not directly reduce CO_2 emissions from natural gas combustion. Instead, NWN might focus more on operational strategies and investments to improve efficiency, reduce methane emissions, and mitigate environmental impacts, such as optimizing pipeline operations, investing in leak detection and repair programs, implementing best practices for pipeline maintenance and integrity management, and upgrading infrastructure to minimize fugitive emissions.

Q. What is Staff's recommendation for this depreciation issue?

[5] NW Natural/Palfreyman-Kravitz/22.

A. Currently, the UM 2312 depreciation filing is under review. The depreciation rates in NWN's filing have about 200 FERC accounts, sub-accounts, and locations. Evaluating the depreciation parameters of the Survival Curve-Projection Life and Net Salvage Rate are useful measures of a company's depreciation policy. Therefore, in the depreciation study review, I would maintain my analytical integrity based on scientific evidence to identify the industrial assets survival rate and net salvage rate and determine and propose fair and reasonable rates.

Docket No: UG 490

Staff/1400
Peng/11

ISSUE 2. AMORTIZATION EXPENSE

Q. What is amortization?

A. Amortization is the practice of spreading an intangible asset's cost over that asset's useful life. In contrast, depreciation is the expensing a fixed asset as it is used to reflect its anticipated deterioration. Accounting rules stipulate that physical, tangible assets (with exceptions for non-depreciable assets) are to be depreciated, while intangible assets are amortized.[6]

Q. Have you made an adjustment to Amortization?

A. Not yet. The UM 2312 depreciation study is currently under review. For the same reason, without a Commission-authorized rate, Staff cannot propose an adjustment.

[6] Source: Investopedia, Amortization vs. Depreciation.

Docket No: UG 490

Staff/1400
Peng/12

ISSUE 3. DEPRECIATION RESERVE

Q. What is depreciation reserve?

A. Depreciation Reserve is also called Accumulated Depreciation Reserve. It is the sum of all recorded depreciation on an asset to a specific date.

Q. What is the Commission's historical treatment of depreciation reserve?

A. Accumulated depreciation reserve refers to the life-to-date depreciation that has been recognized that reduces the book value of an asset. The Commission treats this issue by following Generally Accepted Accounting Principles (GAAP) that is as reserve increases, the Rate Base decreases. Please note, rate base is the value of property on which the utility is allowed to earn a specified rate of return, in accordance with rules set by the Commission. In this issue, rate base is the value of property of a utility minus accumulated depreciation of those assets.

Q. Have you adjusted Depreciation Reserve?

A. Not yet. The depreciation reserves are affected by depreciation expenses, asset retirements, sales, transfers, gross salvage, cost of removal, and other adjustments. If depreciation expense is changed, the accumulated depreciation should be changed accordingly. Currently, the depreciation study UM 2312 is under review. If depreciation expense changes, calculated by new depreciation rates after the Commission's authorization, the accumulated depreciation would be changed accordingly.

Docket No: UG 490

Staff/1400
Peng/13

ISSUE 4. AMORTIZATION RESERVE

Q. Describe Amortization Reserve.

A. Amortization Reserve is accumulated amortization at a point in time, which includes the total amount of recorded amortization, retirements, gross salvage, cost of removal, transfer asset, and other adjustments.

Q. What is the Commission's historical treatment of this issue?

A. Amortization Reserve is also called Accumulated Amortization Reserve. In a revenue requirement, as an amortization reserve increases, the Rate Base decreases. Rate Base is the value of property/assets of a utility minus accumulated amortization of those assets.

Q. Have you made any adjustments to Amortization Reserve?

A. Not at this time. The amortization reserves are affected by amortization expenses. If amortization expense is changed, the accumulated amortization should be changed accordingly. I did not make an adjustment to amortization expense. If any adjustments are made by other Staff witnesses, the Company's final amortization reserve would be changed accordingly.

Docket No: UG 490

Staff/1400
Peng/14

ISSUE 5. AFUDC

Q. What is AFUDC?

A. Electric (Gas) Plant Instruction No. 3(17) provides a formula for computing rates used to capitalize Allowances for Funds Used During Construction (AFUDC).[7] The formula includes a component for the weighted average cost of long-term debt. The entire issue of the use-restricted long-term debt should be included with other long-term debt used in calculating AFUDC rates. Average balances of the trust or other special funds should be included in the computation of the average balance of Construction Work in Progress (CWIP) used in the formula.

AFUDC assigned to the project should be determined by applying AFUDC rates to the eligible project expenditures and also balances in the trust or special funds. Fund earnings during construction should be credited to the cost of construction of the project facilities.

Q. What is the purpose of the AFUDC review?

A. The purpose of this review is to address whether the Company complied with guidance[8] related to AFUDC and the capitalization of assets based on the regulations of both the Federal Energy Regulatory Commission (FERC) and the Oregon Public Utility Commission (OPUC) in this filing.

Q. Please provide more details regarding AFUDC.

---

7 https://www.ferc.gov/enforcement-legal/enforcement/accounting-matters/allowance-funds-used-during-construction.

8 FERC 18 C.F.R. Part 101 (17). https://www.law.cornell.edu/cfr/text/18/part-101

A. AFUDC is a non-cash item that is included in the cost of Utility Group utility plant and represents the cost of borrowed and equity funds used to finance construction. AFUDC is the cost of both the debt and equity funds used to finance utility plant additions during the construction period for such additions, determined in accordance with Generally Accepted Accounting Principles (GAAP).

FERC has prescribed two formulas for calculating maximum allowable AFUDC rates:[9]

1. DEBT: This formula determines the maximum rate that can be used to capitalize an allowance for borrowed funds (i.e., debt) used for construction purposes.
2. COMMON EQUITY: This formula determines the maximum rate that can be used to capitalize an allowance for other funds (e.g., common equity) used for construction purposes.

FERC has indicated that if the FERC AFUDC rate is different than the state-approved rate, the AFUDC capitalized should be split between utility plant and a regulatory asset. The amount capitalized in utility plant would be based on the FERC AFUDC rate. The amount included in the regulatory asset would be the difference between the State AFUDC rate and the FERC AFUDC rate.

The FERC formula and elements for the computation of the allowance for funds used during construction are:[10]

[9] FERC 18 C.F.R. Part 101 (17). https://www.law.cornell.edu/cfr/text/18/part-101
[10] FERC 18 C.F.R. Part 101 (17) Allowance for funds used during construction (a), (b): https://www.law.cornell.edu/cfr/text/18/part-101

Ai=s*(S/W)+d*(D/D+P+C)*(1-S/W) = Gross allowance for borrowed funds used during construction rate

Ae=[1-S/W]*[p*(P/D+P+C)+c*(C/D+P+C)] = Allowance for other funds used during construction rate

- S=Average short-term debt
- s=Short-term debt interest rate
- D=Long-term debt
- d=Long-term debt interest rate
- P=Preferred stock
- p=Preferred stock cost rate
- C=Common equity
- c=Common equity cost rate
- W= Average balance in construction work in progress, less asset retirement costs related to plant under construction

Q. What is the Regulatory Treatment for AFUDC in Oregon?

A. OPUC allows utilities to include the capitalized AFUDC as part of the rate base. This allows the utility to recover the cost of financing during construction through rates charged to customers. The AFUDC rate is an important component of a utility's rate base, allowing the utility to recover the cost of financing construction expenditures incurred during the development of long-term projects.

Q. Is the AFUDC rate included in the rate base?

A. Yes. AFUDC Rate (%) represents the cost of capital for the utility, including both debt and equity. Including AFUDC in the rate base helps ensure that the utility is able to earn a fair return on its investments while providing customers with reliable service at reasonable rates. Also, please note, the AFUDC rate is

related to interest costs; it is not a fixed interest rate but rather a rate used to capitalize interest expenses during the construction period of long-term assets.

Q. Did you make any adjustments after your review?

A. Yes. The AFUDC rate cannot exceed the overall rate of return applied to rate base, to ensure Oregon-jurisdictional rates are just and reasonable. I proposed an adjustment to NWN's 2023 AFUDC rate for the following reasons:

NWN calculated total AFUDC rate in 2023 was 7.47 percent, which exceeded OPUC-authorized Weighted Average Cost of Capital (WACC) rate of 6.84 percent.

UG 490	Calculated AFUDC Rate					rate of return
DR 369	AFUDC	AFUDC	AFUDC	Authorized	Authorized	Authorized
Year	Debt	Equity	Total AFUDC	LT Debt	Common Equity	WACC
	Rate	Rate	Rate	Rate	Rate	Rate
2023	3.05%	4.42%	7.47%	4.48%	9.40%	6.84%

In 2023, NWN's total AFUDC rate is higher than the state-authorized rate of return, the portion of AFUDC that exceeds the authorized rate is 0.63 percent (=7.47 percent - 6.84 percent). When the total AFUDC rate is higher than the state-authorized rate of return, the portion of AFUDC that exceeds the authorized rate is typically recorded as a regulatory liability on the utility's balance sheet. Therefore, I recommend:

1. NWN's AFUDC capitalized should be split between Utility Plant and a Regulatory Asset.
2. NWN should record the exceeded portion as a "Excess AFUDC Regulatory Liability" on the utility's balance sheet. This regulatory liability

represents the amount that the utility is not currently authorized to recover from ratepayers but may be eligible for recovery in the future.

3. Check errors in the capital structure calculation. NWN might need to identify if any data or calculation procedure errors occurred. For example, a short-term and long-term debts in capital structure, because Oregon's capital structure does not include a short-term debt. NWN should also check CWIP eligibility to find the impact on capitalized AFUDC, because the material deviations in excess of 25 basis points could result in significant AFUDC errors.

Ultimately, to be recoverable in rates, amounts in NW Natural's Excess AFUDC Regulatory Liability account would be subject to regulatory review, adjustment, and approval in a rate proceeding.

Q. Did you make any additional adjustments to the AFUDC issue?

A. No. NWN complied with the OPUC policy to exclude CWIP in the rate base, because Oregon does not allow a utility to recover costs of a plant not yet placed in service in retail rates. The Company's AFUDC calculations meet FERC calculation procedures and meet Oregon regulatory requirements.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 490
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1401

Witness Qualifications Statement

April 18, 2024

Docket No. UG 490

Staff/1401
Peng/1

WITNESS QUALIFICATIONS STATEMENT

NAME: Ms. Ming Peng

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist
Accounting and Finance Section of the Rates, Safety and Utility Performance Program

ADDRESS: 201 High Street SE, Suite 100
Salem, OR 97301

EDUCATION & TRAINING:

M.S. Applied Economics
University of Idaho, Moscow

B.S. Statistics
People's University of China, Beijing

CRRA Certified Rate of Return Analyst in 2002
Society of Utility and Regulatory Financial Analysts

Depreciation studies – the Society of
Depreciation Professionals

NARUC Annual Regulatory Studies Program
Michigan State University, East Lansing

400+ credit hours on 30+ training topics in the public utility industry

EXPERIENCE: 1/11/1999 – Present, Public Utility Commission of Oregon

I have been employed by the Public Utility Commission of Oregon (Commission) for 25 years. My roles have included:

Expert Witness, Case Manager, Principal Analyst, Econometrician, Economist, Utility Analyst, and Policy Analyst.

Docket No. UG 490 Staff/1401
Peng/2

I have testified in various formal state hearings and performed numerous analyses, including economic, financial, statistical, mathematical, marketing, and policy analyses in the public utility industry.

Principal Analyst and Case Manager, Settlement Lead/Negotiator for Depreciation Ratemaking:
I have served as a Principal Analyst and Case Manager for the determination of Energy Property Depreciation Rates (Oregon Revised Statute 757.140) for the past 15 years. In this role, I've had a strong focus on Depreciation Rate Determination (fixed cost allocation, and capital recovery). I was also a Principal Analyst and Case Manager for the determination of Energy Property Depreciation Rates (Oregon Revised Statute 757.140) during this time period.

In this position, I investigated, analyzed, and calculated energy asset retirement cost and impact, as well as power plant decommissioning cost and impact, on customer rates. I reviewed, calculated, and analyzed fixed asset depreciation and proposed depreciation parameters for each of FERC accounts on Generation, Transmission, Distribution, General, and Coal Mining Plants. The energy sources I have worked on Steam/Coal, Hydraulic, Natural Gas, Wind, Solar, and Geothermal.

My analyses of "Power-Plant-Shutdown" activities (accelerated plant retirement, and decommissioning cost recovery) include the following cases:

1. PGE closes Boardman Coal-fired plant (UM 1679 & UE 215).
2. PacifiCorp closes Carbon Coal Plant in Utah (UE 246).
3. Multi-state PacifiCorp Klamath Hydro Dam Removal Cost recovery for (1) J. C. Boyle Dam, (2) Copco 1 Dam, (3) Copco 2 Dam, and (4) Iron Gate Dam removal under ORS 757.734 – Recovery of investment in Klamath River dams in OPUC UE 219.
4. Idaho Power Valmy Coal-fired power plant Shutdown (UE 316).
5. PGE Colstrip Coal-fired power plant Shutdown (UM 1809).

I conduct case investigations and analyses on Utility's filings, make rate adjustments, lead settlement negotiation, prepare testimony, and appear on behalf of the Commission. The energy companies I work with are: (1) PacifiCorp (serves 6 states), (2) PGE, (3) Northwest Natural Gas (NWN), (4) Idaho Power, (5) Avista Corp (Washington), and (6) Cascade Gas (CNG; Montana).

Lead Analyst and Case Manager on Financial Dockets:

Prior to my current position, I was a Lead Analyst and Case Manager for cost of debt capital for nine years. I reviewed market risks, derivatives and hedging, debt issuance, and stock flotation. My analysis directly informed utility and energy policy.

Docket No. UG 490 Staff/1401
Peng/3

I advised the Commission on over 60 financial dockets. The Commission incorporated all of my recommendations into final orders.

I was certified by the Society of Utility and Regulatory Financial Analysts as a Certified Rate of Return Analyst in 2002.

Public Utility & Policy Analyst:

Rulemaking: I have formulated energy regulation rules for utility performance incentives and cost-of-service regulation.

Energy Utility Merger & Acquisition: I have testified in formal state hearings involving utility mergers & acquisitions. I conducted Acquisition Premiums & Credit Risk Analysis and testified on behalf of the Commission in MidAmerican Energy Company's application to purchase PacifiCorp. I also reviewed Scottish Power's earlier purchase of PacifiCorp, and PGE's emergence from Enron after the Enron bankruptcy.

Integrated Resource Planning (IRP, Least Cost Planning): I provided comments to the Commission for decision making on Boardman to Hemingway (B2H), a 500-kV transmission power line, which included a cost and benefit list, a pros and cons list, alternatives, and the relevant legal risks. I also provided comments on utility's IRPs, such as total cost for power generation, power capacity (MW) replacement cost, avoided cost for free fuel, and emission trading cost.

Clean Energy – Dollar Impact on Customer Rates: I analyzed and calculated the rate impact and comparative advantage of clean energy. I built the portfolio optimization models to analyze the coal-fired generating capacity replacement.

General Rate Cases: I have been a part of *almost every energy rate case* since I joined the Oregon PUC on January 11, 1999. Historically, my reviews included fuel price forecasting, property sales, load forecasting, weather normalizations, cost of debt, and capital structures. Currently, my reviews are focused on depreciation and reserve, and AFUDC Capitalization Policy.

Survey Sampling Design: Results of my statistical sampling design and sampling procedures are incorporated into my revenue requirement testimony in Commission Docket No. UM 1288.

Auditing, Interest Rate, Late Payment: I audited cost of capital and financial components. My survey report and analyses are published annually for Oregon (UM 779).

Survey for Market Competition & Economic Policy: I conducted and wrote the report on Telecommunications, "Market Competition and Economic Policy Survey

Analysis" for House Bill 2577. This report has been published on the OPUC web annually for 15 years.

Mentor in the ICER - International Confederation of Energy Regulators: I was selected to act as a mentor in the ICER (International Confederation of Energy Regulators) Women in Energy (ICER WIE) pilot mentoring program. My mentoring topics focus on Incentive Regulation; Rate and Economic Impacts of "Cost-of-Service" regulation in the U.S.; "Price-Cap Performance Based Regulation" in UK; Cost of Capital, Energy Demand and Price Forecasting Modeling; Least Cost Planning; Regulatory Policy; and Renewable Energy issues within regulated rate structures.

CASE: UG 490
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1402

Exhibits in Support
Of Opening Testimony

April 18, 2024

Staff/1402
Docket No: UG 490 Peng/1

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 372

In Attachment A, tab name "490 AFUDC Calc", please fill out the columns M, N, O, keep the calculation formulas in Excel, and explain in detail whether the Company's calculations of its AFUDC rates comply with the FERC AFUDC rate formulas and accounting requirements.

The explanation should include the following details:

a. Under FERC AFUDC Accounting, the formulas assume that short-term debt is the first source of construction funding. If the balance of "short-term debt exceeds the average balance of CWIP," the total AFUDC rate is comprised of only an allowance for borrowed funds used during construction equal to the short-term debt rate. Were these the assumptions you based the calculations on?

b. If the average balance of "CWIP exceeds the balance of short-term debt", the calculation assumes that the construction funding was not met by short term debt. How did the Company incorporate the different capital sources and cost rates to arrive at the total debt and other funds maximum allowable AFUDC rates? Please explain.

Response:

Please see the Company's response to UG 490 OPUC DR 369.

a. Yes. If the balance of short-term debt exceeds the average balance of CWIP, the total AFUDC consists only of short-term debt.

b. If the average balance of CWIP exceeds the balance of short-term debt, the Company's calculation assumes that the construction funding was not met by short term debt, and the Company then uses the weighted average cost of capital (WACC) to incorporate the Company's other capital sources to arrive at the total debt and equity rates to use for AFUDC.

CASE: UG 490
WITNESS: Nicola Peterson

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1500

Opening Testimony
Medical Benefits and Pensions

April 8, 2024

Docket No: UG 490

Staff/1500
Peterson/1

Q. Please state your name, occupation, and business address.

A. My name is Nicola Peterson. I am a Senior Telecoms Analyst employed in the Rates Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement, which details my educational background and work experience can be found in Exhibit Staff/1501.

Q. Did you prepare any exhibits?

A. Yes. Exhibit Staff/1501 is my Witness Qualification Statement.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss NW Natural's Test Year Employee Medical Benefit and Pension costs. My testimony is limited to current employee expenses and does not cover post-retirement amounts.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Medical and Health Insurance 2
Figure 1: OR Allocated Totals for Medical Benefit Costs 3
Figure 2: Total Benefits Per FTE Expenses 3
Issue 2. Current Pension Costs 6
Figure 4: Utility Retirement Benefits 7
Figure 5: Adjustment calculation 7
Summary of Findings and Recommendations 8

Docket No: UG 490

Staff/1500
Peterson/2

ISSUE 1. MEDICAL AND HEALTH INSURANCE

Q. Please describe the Company's request regarding medical and health insurance.

A. NW Natural included $19.6 million in medical and dental benefits for the Test Year.[1] The expense includes costs for both bargaining (union) and non-bargaining (non-union) (NBU) employees and is roughly split between the two groups.

NW Natural described the medical benefits provided to its employees and the steps it had taken to mitigate costs. NW Natural also included in its testimony the results of an independent survey that rated the health benefits offered by the NWN in comparison to 34 other Utilities in the PNW. NW Naturals offerings were rated as equal to and substantially at market.[2]

Q. Please discuss Staff's analysis of this issue.

A. Staff analyzed the information provided in NW Natural's testimony and the four-year trend in Figure 1 below. Staff also looked at these costs on a per FTE basis in relation to applicable FTE increases and industry inflation expectations. Staff issued data requests asking for reconciliations for clarification of amounts and explanations of specific increases in costs.

Figure 1 shows the benefits, both medical and pension in the NWN application that Staff has analyzed to date. Staff added the percent increase from Base year to Test Year.

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1 NWN Response to SDR 63.
2 NW Natural/Rogers/14-15.

Docket No: UG 490

Staff/1500
Peterson/3

FIGURE 1: OR ALLOCATED TOTALS FOR MEDICAL BENEFIT COSTS

Utility Oregon	Test Year 2025	Base Year 2023	% BY to TY	Base Year -1 2022	Base year -2 2021
Medical/Dental	$ 19,562,722	$ 16,321,054	20%	$ 15,799,591	$ 16,217,793
401(k)	$ 5,720,041	$ 5,328,286	7%	$ 4,886,964	$ 4,599,304
Group Life Insurance	$ 158,989	$ 139,926	14%	$ 139,070	$ 135,752
Retiree Life Insurance	$ 126,274	$ 121,173	4%	$ 117,634	$ 119,490
LT Disability	$ 721,102	$ 599,584	20%	$ 585,819	$ 564,836
Other	$ 168,421	$ 165,127	2%	$ 147,348	$ 145,753
Total	**$ 26,457,550**	**$ 22,675,150**	**17%**	**$ 21,676,426**	**$ 21,782,928**

According to NW Natural, medical costs increased by 7.1 percent in 2023 and are expected to rise further in 2024 by 9.5 percent.[3]

Figure 2 shows NW Natural' s forecasted employee benefit costs on an FTE basis.

FIGURE 2: TOTAL BENEFITS PER FTE EXPENSES

	Test Year Per FTE 1247	Base year Per FTE 1210	Per FTE % change
Medical/Dental	$18,462	$15,896	16%
401(k)	$5,398	$5,190	4%
Group Life Insurance	$150	$136	10%
Retiree Life Insurance	$119	$118	1%
LT Disability	$681	$584	17%
Other	$159	$161	-1%
Total	**$24,968**	**$22,085**	**13%**

Medical benefit costs per FTE are increasing over the Base Year by 16 percent, however on an FTE basis, total benefit costs are increasing by only 13 percent. From the above table we can see that it is primarily due to the small increase in 401k benefits that is causing this difference.

[3] NW Natural/1000, Rogers/15.

Staff compared these increases to other industry projections. PwC Health Research Institute[4] forecasts health care costs to increase by 7 percent in 2024 compared to a 6 percent rise in 2023. The Peterson Center on Healthcare and Kaiser Family Foundation[5] predict health care costs to rise by 5 percent in 2024.

Q. Does Staff agree with the Company's proposal?

A. Staff recognizes that the Company's forecasted costs are higher than what is indicated by the percentage increases forecasted by the Peterson Center, PwC Health Research, and Kaiser Family Foundation noted above. However, assuming the percentage increase for NWN's benefits is as reported in the tables above, Staff does not believe an adjustment to NW Natural's forecast of costs is warranted. However, Staff does have an adjustment to align the Test Year amount for medical benefits with the adjusted number of FTEs that Staff witness Steph Yamada is proposing in Staff/2000. This adjustment is equal to a reduction of 20.96 FTE. Also, as explained below, Staff is waiting for additional information regarding NW Natural's costs for employee benefits before reaching its final conclusion regarding the reasonableness of NW Natural's Test Year forecast for employee benefits.

Q. Please explain why you are waiting for additional information.

4 https://www.pwc.com/us/en/industries/health-industries/library/behind-the-numbers.html.
5 Health Cost and Affordability Policy Issues and Trends to Watch in 2024 - Peterson-KFF Health System Tracker.

Docket No: UG 490

Staff/1500
Peterson/5

A. Staff based its analysis and proposed adjustment amounts included in the Company's response to SDR 63, which asks for medical benefit costs for the Test Year, Base Year, and the three years prior to the Base Year. However, according to the Company's reply to DR 478, the amounts in SDR 63 represent the O&M allocated payroll overheads only. Therefore, at this time, Staff also is only proposing an adjustment to O&M expense based on the Staff-proposed adjustment to FTEs. Further clarification is required prior to recommending an adjustment to capitalized benefits or before Staff can draw conclusions regarding the overall level of costs.

Docket No: UG 490

Staff/1500
Peterson/6

ISSUE 2. CURRENT PENSION COSTS

Q. Please describe the Company's request regarding current pension costs.

A. NW Natural included $10.8 million in retirement benefits for the Test Year. [6] The expense includes costs for both RKSP – Matching Contribution which is open to all employees, and RKSP – Enhanced Contribution, which is open to NBU employees hired after December 31, 2006, and BU employees hired after December 31, 2009. NWN Natural's defined benefits plan, "NW Natural Retirement Plan," is closed to new employees hired after the dates listed above.

RKSP – Matching is a savings plan with employer match based on the percentage saved by the employee, and NW Natural included in their Initial application details of a change in proposed Employer contribution rate. RKSP – Enhanced, includes a fixed Employer contribution rate and requires no employee contribution and therefore should increase in line with salaries and wages.

Q. Please discuss Staff's analysis of this issue.

A. Staff analyzed the information provided in the application and compared it to the information provided in the previous rate case UG 435.[7] See Figure 4 below.

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[6] NW Natural/1000, Rogers/20.

[7] *NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision*, UG 435 (filed December 17, 2021).

Docket No: UG 490

Staff/1500
Peterson/7

FIGURE 4: UTILITY RETIREMENT BENEFITS

	Test Year	UG435 Test Yr	% Change
RKSP-Matching Contribution	$ 5,720,000	$ 5,136,300	11.36%
RKSP-Enhanced Contribution	$ 4,588,300	$ 3,851,200	19.14%
WSP-Withdrawal Liability	$ 497,100	$ 506,100	-1.77%
Total	$ 10,805,400	$ 9,493,600	13.81%

Staff found an overall increase of 14 percent over the retirement benefits included in NWN's previous rate case.

Q. Does Staff agree with the Company's proposal?

A. Staff is currently unable to ascertain whether the Company's proposed cost for pensions per FTE is reasonable because Staff is still investigating the capitalized pension costs.

Q. Does Staff have a proposed adjustment at this time?

A. Staff is proposing a combined adjustment of ($523,336), which is based on the fact that both medical and pension Costs are FTE dependent. Staff has calculated a per FTE expense and reduction. This adjustment is based on the amounts included in SDR 63 and an FTE adjustment of (20.96). This adjustment is part of the payroll overhead.

FIGURE 5: ADJUSTMENT CALCULATION

	OR Allocated
Total Medical & Pension Benefit per FTE expense	$24,968
FTE Adj	(20.96)
Total Adjustment	**($523,336)**

Docket No: UG 490

Staff/1500
Peterson/8

SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. Please summarize your findings and recommendations.

A. Staff's recommendations are as follows:

- Forecasted medical and health Insurance. Staff agrees with the Company's cost per FTE and is currently only recommending adjusting these expenses in line with the adjustments Staff is proposing with regard to number of FTE. This is currently an adjustment to O&M only and additional adjustments to Capital maybe forthcoming. That adjustment is included in the figure below.
- Forecasted pension costs. Staff is awaiting responses to data requests and clarity regarding the Company's capitalized pension costs before reaching a decision as to whether the Company's total proposed pension costs is reasonable. Therefore, Staff is currently only recommending adjusting the Company's proposed O&M expense for pensions in line with the adjustments Staff is proposing with regard to number of FTE.

Staff is recommending a combined adjustment to Test year expense of ($523,336).

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 490
WITNESS: NICOLA PETERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1501

Witness Qualifications Statement

April 18, 2024

Docket No. UG 490

Staff/1501
Peterson/1

WITNESS QUALIFICATIONS STATEMENT

NAME: Nicola Peterson

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Telecommunications Analyst
Rates and Telecommunications Section
Rates, Safety and Utility Performance Program

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION: BA (Hons) Accounting & Finance
Middlesex University
Associate Chartered Accountant – Institute of Chartered Accountants of England & Wales

EXPERIENCE: I have been employed with the Public Utility Commission of Oregon since 2014. I am a Senior Telecommunications analyst in the Rates and Telecommunications Section of the Safety and Utility Performance Program. My assignments have mainly involved the administration and organization of the Oregon Universal Service Fund (OUSF). I have been the case manager on several OUSF dockets, managing workshops and stakeholder conferences, as well as chairing the OUSF Advisory Board. My other assignments include analysis of tariff filings, rulemakings, eligible telecommunication carrier certification with the FCC and annual reporting and budgeting.

Prior to the OPUC, I began my career in public practice as a Chartered Accountant and Audit Senior and then moved into the telecommunications industry. I have worked for numerous telecommunication companies (NYNEX, British Telecom, Esat Ireland, Digicel Jamaica) in various finance roles, from Financial Analyst to Financial Controller/ Finance Director.

CASE: UG 490
WITNESS: ROSE PILEGGI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1600

Opening Testimony
Capital Structure

April 18, 2024

Docket No: UG 490

Staff/1600
Pileggi/1

Q. Please state your name, occupation, and business address.

A. My name is Rose Pileggi. I am a Senior Energy Analyst employed in the Rates, Safety and Utility Performance Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/1601.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the Company's testimony on Capital Structure.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared Exhibit Staff/1602, responses to Staff Data Requests.

Docket No: UG 490

Staff/1600
Pileggi/2

ISSUE 1. CAPITAL STRUCTURE

Q. When did the Commission last consider this issue?

A. The Commission entered Order No. 22-388 in Docket No. UG 435 adopting a partial stipulation in which the parties agreed to a capital structure of 50 percent equity and 50 percent long-term debt.[1] This is the same capital structure proposed by NW Natural (NWN or Company) in its initial filing in Docket No. UG 435.

Q. What capital structure did the Company propose in its opening testimony?

A. NW Natural has proposed a capital structure in its current General Rate Case (GRC) of 50 percent equity and 50 percent long-term debt.[2]

Q. Does the Company always maintain a precise 50/50 capital structure?

A. No. NW Natural's capital structure fluctuates over time. The fluctuations are expected as issuances, redemptions, and maturations on financial instruments are not in perfect sync nor is it always beneficial for the company to maintain a perfectly uniform capital structure. NW Natural provided the previous 5 years of data on capital structure in response to Staff Data Request No. 286.[3]

Q. Did NW Natural maintain a capital structure near its 50/50 capital structure over the past 5 years?

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1 *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision,* UG 435, Order No. 22-388 (October 24, 2022).
2 NW Natural/300, Wilson/1, line 16.
3 See Staff/1602, Pileggi/1.

A. Yes. The Company experienced swings in capital structure in which the equity percentage ranged from a low of 47.9 percent to a high of 51.4 percent. The average equity percentage over this period was 49.0 percent.

Q. How has the Commission treated capital structure for NW Natural's peers in recent years?

A. In UG 461, the Commission approved a stipulation for a 50 percent equity and 50 percent long-term debt capital structure for Avista. In UG 390, the Commission approved a stipulation for a 50 percent equity and 50 percent long-term debt capital structure for Cascade Natural Gas.

Q. What does Staff recommend for the capital structure of NW Natural?

A. Staff recommends a notional capital structure of 50 percent equity and 50 percent long-term debt. The notional capital structure acknowledges that the Company knows what timing of debt and equity issuances works best for the Company and centers around the typical 50/50 split that NW Natural and its peers already utilize. While rates charged to customers are based on a 50/50 capital structure, the Company may operate on the financing authorizations granted by the Oregon PUC and capital structures it chooses consistent with those authorizations. This is no different than any other cost or expense item projected in the test year. Those decisions by the Commission do not constrain the Company to incur those exact expense level decisions by the Commission.

Q. Could Staff's position change on this issue?

A. Staff will closely monitor the Company's and intervenors' testimony and analysis, which will be considered in Staff analysis and rebuttal testimony.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 490
WITNESS: ROSE PILEGGI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1601

Witness Qualifications Statement

April 18, 2024

Docket No. UG 490

Staff/1601
Pileggi/1

WITNESS QUALIFICATIONS STATEMENT

NAME: Rose T. Pileggi

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Utility Analyst
Energy Costs Section

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION: In 2013, I received a Bachelor of Science in Business Administration from Thomas Edison State University. In 2017, I received a Master of Science in Finance from the University of Portland.

EXPERIENCE: I have been employed by the Commission since July of 2022 analyzing finance, power cost, rate case and affiliated interest dockets.

From July 2021 through June 2022, I worked as an Analyst for the Oregon Judicial Department. Duties included data analysis, ensuring compliance with pertinent statutes and rules to ensure that data was being handled in accordance with requirements and recommending process improvements.

From 2017 to 2021, I worked as an Investment Analyst, Portfolio Manager, and Systems Manager for Northwest Capital Management. My work included analysis of the markets and investments, the management and rebalancing of portfolios, creating reports as required by the SEC, as well as managing software integrations for operational and reporting purposes.

CASE: UG 490
WITNESS: ROSE PILEGGI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1602

Exhibits in Support
Of Opening Testimony

April 18, 2024

Staff/1602
Docket No: UG 490 Pileggi/1

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 286

Please provide the Company's actual capital structure over the last 5 historical years and through the Company's test year. For the calculation of capital structure, please average all 12 monthly capital structures for the calendar year. The response should fill the provided tables.

Response:

Please see the filled in tables. NOTE: The Year Average figures provided above are the result of a 13-month AMA calculation, consistent with the methodology used in the Earnings Test and in UG 490. The calculation includes December of the previous year; and both the previous December and current December are given ½ weight.

Year	Year-End		Year Average	
	Equity %	Long-Term Debt %	Equity %	Long-Term Debt %
2019	49.18%	50.82%	49.07%	50.93%
2020	47.46%	52.54%	48.00%	52.00%
2021	49.58%	50.42%	48.62%	51.38%
2022	50.61%	49.39%	51.43%	48.57%
2023	47.48%	52.52%	47.87%	52.13%
[redacted]				

*Forecasted value

Docket No: UG 490

Equity in Dollars

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2019	741,401,550	747,701,219	747,442,410	753,082,952	737,424,483	830,176,987	823,886,959	804,638,974	798,975,925	801,855,436	803,841,451	822,396,768
2020	844,992,113	849,218,800	857,858,011	861,339,855	845,245,992	839,437,550	830,907,305	810,200,544	805,543,627	805,585,192	809,612,267	835,214,333
2021	860,915,951	870,861,026	881,606,789	887,765,096	873,445,101	868,449,970	861,071,058	841,747,599	835,817,950	848,312,512	942,003,840	978,170,501
2022	978,807,635	979,020,556	978,731,720	1,118,572,108	1,118,740,189	1,143,839,440	1,147,255,337	1,158,012,151	1,157,882,907	1,158,037,966	1,158,464,201	1,162,670,812
2023	1,224,556,337	1,235,045,607	1,250,553,362	1,235,511,724	1,217,204,595	1,210,601,010	1,201,962,749	1,176,032,058	1,202,386,561	1,205,224,034	1,206,091,745	1,233,641,559

Long-Term Debt in Dollars

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2019	739,700,000	739,700,000	739,700,000	739,700,000	739,700,000	879,700,000	879,700,000	879,700,000	869,700,000	869,700,000	869,700,000	849,700,000
2020	849,700,000	774,700,000	924,700,000	924,700,000	924,700,000	924,700,000	924,700,000	924,700,000	924,700,000	924,700,000	924,700,000	924,700,000

Docket No: UG 490

2021	924,700,000	924,700,000	924,700,000	924,700,000	924,700,000	924,700,000	924,700,000	914,700,000	864,700,000	864,700,000	994,700,000	994,700,000
2022	994,700,000	994,700,000	994,700,000	994,700,000	994,700,000	994,700,000	994,700,000	994,700,000	1,134,700,000	1,134,700,000	1,134,700,000	1,134,700,000
2023	1,225,727,836	1,225,715,409	1,324,422,457	1,324,468,682	1,324,508,417	1,324,559,042	1,324,608,342	1,404,475,530	1,404,552,884	1,404,619,144	1,364,673,440	1,364,731,949

CASE: UG 490
WITNESS: PAUL ROSSOW

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1700

Opening Testimony
Political Activities, Advertising, Memberships, Dues, and Donations Meals and Entertainment, Awards, Gifts, Airfare, Lodging, and Travel

April 18, 2024

Docket No: UG 490

Staff/1700
Rossow/1

Q. Please state your name, occupation, and business address.

A. My name is Paul Rossow. I am a Utility Analyst employed in the Accounting and Finance Section of the Rates, Safety and Utility Performance Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/1701.

Q. What is the purpose of your testimony?

A. I discuss my review of several topics of NW Natural's (NWN or Company) Test Year Operations and Maintenance (O&M) non-payroll expenses, including expenses for political activities, advertising expenses, memberships, dues and donations, meals and entertainment, awards, gifts, airfare, lodging, and travel.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared the following support exhibits:

Exhibit Staff/1701. Witness Qualification Statement
Exhibit Staff/1702. Responses to Data Requests (Non-Confidential)
Exhibit Staff/1703. Membership Work Paper (Non-Confidential)
Exhibit Staff/1704. Meals and Entertainment Work Paper (Non-Confidential)

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Political Activities 3
Issue 2. Advertising 5
Issue 4. Memberships, Dues, and Donations 11
Issue 5. Meals and Entertainment, Awards, Gifts, Refreshments, Airfare, Lodging, and Travel 14
Summary. Findings and Recommendations 17

Docket No: UG 490

Staff/1700
Rossow/2

Q. Could there be changes or updates to Staff's position and recommendations?

A. Yes. My testimony addresses issues identified to date. My recommendations and issues may change when informed by new data and after reviewing testimony and analysis by other parties.

Docket No: UG 490

Staff/1700
Rossow/3

ISSUE 1. POLITICAL ACTIVITIES

Q. Please explain the Commission's historical treatment of political activities.

A. The Commission has not allowed regulated utilities to recover political activity or lobbying expenses through rates charged for regulated services. Political activity along with lobbying are discretionary and are not required to provide safe and adequate service to customers.[1]

Political activities and lobbying expenses can occur by:

- Directly communicating with officials,
- Providing transportation for elected officials,
- Attending government conferences and expressing special interest views,
- Drafting special interest legislation and presenting it to a legislator for consideration,
- Providing support for elected officials on trade missions, by providing in kind services to special interest groups,
- Hosting receptions for congressional delegations, and
- Attempting to influence legislators and other public officials to introduce or support measures that favor some special interest.

[1] *In re Pacific Northwest Bell Telephone Company,* UT 43, Order No. 87-406 (March 31, 1987) (1987 WL 257178), p. 43: "The Commissioner views lobbying and similar political activities as essentially the same issue presented by community activities. Ratepayers should not be required to contribute to the advancement of political positions in which they may not believe. *See Pacific Power & Light Company* [*PacifiCorp*], UF 3074, Order 74-658 at 13."

Q. Does NW Natural seek recovery of expense for political activities or lobbying in this rate case?

A. The Company testifies it is not seeking recovery for these expenses in the 2025 Test Year.[2]

Q. Please describe your analysis for the political activities and lobbying expenses.

A. Staff reviewed NWN's Direct Testimony, issued Data Request Nos. 341 – 351, and analyzed NW Natural's transactional data in its response to Standard Data Request No. 57. Staff noted 104 lobbying transactions recorded to cost element titled "Meals and Entertainment" that Staff recommends expenses excluding 100 percent, which revealed $12,535 recorded to the total Company's Base Year under FERC Account 921. This equates to an Oregon Base Year allocated amount of $11,047.

Next, Staff applied All-Urban CPI inflation factors of 2.7 percent and 2.0 percent in 2024 and 2025, respectively, resulting in an Oregon escalated Test Year adjustment to Lobby expenses of ($11,572).

Q. What are Staff's findings regarding political activities and lobby expenses?

A. Staff finds that an adjustment of ($11,572) is needed for the Test Year.

[2] NW Natural/1200, Williams/2-7.

Docket No: UG 490

Staff/1700
Rossow/5

ISSUE 2. ADVERTISING

Q. Does the Commission have a standard means of determining how advertising expenses are treated?

A. Yes. OAR 860-026-0022 specifies how advertising expenses are treated in a utility rate case. The rule describes five categories (A-E), each with a different standard for inclusion in rates.

Category “A” includes energy efficiency or conservation advertising expenses that do not relate to a Commission-approved program, utility service advertising expenses, and utility information advertising expenses.[3] Category A advertising expenses no greater than twelve and one-half hundredths of one percent (0.125 percent) of the gross retail operating revenues determined in that proceeding are presumed just and reasonable for rate making purposes, though the presumption is rebuttable.[4] The utility bears the burden to prove that any Category A expense that exceeds the threshold is just and reasonable for ratemaking purposes.

Category “B” includes legally mandated advertising expenses, which are assumed to be reasonable for rate making purposes.[5]

Category "C” includes institutional advertising expenses, promotional advertising expenses, and any other advertising expenses not fitting into Category “A”, “B”, or “D”.[6] Utilities must demonstrate these expenses are just

3 OAR 860-026-0022(2)(a).
4 OAR 860-026-0022(3)(a).
5 OAR 860-026-0022(2)(b).
6 OAR 860-026-0022(2)(c).

and reasonable for inclusion in rates, as well as separately state the amount of advertising expenses in this category.

Category "D" includes political advertising expenses and non-utility advertising expenses, which are presumed to be not just and reasonable for ratemaking purposes.[7]

Lastly, Category "E" includes energy efficiency or conservation advertising expenses that relate to a Commission approved program. Utilities must show these expenses are reasonable and recoverable in rates. With Commission approval, advertising expenses in Category "E" may be capitalized.[8]

Q. Please describe the Company's Oregon Test Year expense for advertising.

A. The Company proposes to include $1,378,465 in Category A and $975,000 in its Category B advertising in the 2025 Test Year as illustrated in Figure 1. The Company reports it has not included any expense for Categories C, D, or E advertising in the 2025 Test Year.

FIGURE 1. TOTAL ADVERTISING IN THE TEST YEAR

Category	Included in Rates?	2025 Expenses $
A	Yes	$1,378,465
B	Yes	$975,163
C	No	$0
D	No	$0
E	No	$0
Total		$2,353,628

7 OAR 860-026-0022(2)(d).
8 OAR 860-026-0022(2)(e).

Q. Please describe your analysis of NW Natural's proposed advertising expenses for Category A.

A. Staff analyzed NW Natural's advertising data in its response to Standard Data Request Nos. 57, 104, 335 -340, and 454, which inquired about NW Natural's advertising expenditures. Staff confirmed that advertisements were related to energy efficiency, safety, and conservation.

Q. How does the Company's Oregon Test Year advertising expenses compare to historical spending?

A. NW Natural's Oregon Test Year request of $1,378,465 for Category A expenses is a 20 percent increase from what was allowed in UG 435 Test Year expense for Category A of $1,148,090.[9]

The Company's Oregon Test Year request of $975,163 for Category B expense is an 18 percent increase from what was allowed in UG 435 Test Year expense for Category B of $827,027.[10]

Q. Please describe how the Category A Test Year expenses are calculated for Oregon ratepayers.

A. Staff's review found that NW Natural is proposing Category A advertising expense of $1.95 per customer, which is $0.03 higher than the amount that is presumed reasonable under OAR 860-026-0022(3)(a).

[9] Staff/1702, NWN Response to DR 338.
[10] Ibid.

Docket No: UG 490

Staff/1700
Rossow/8

FIGURE 2. 2025 TEST YEAR CATEGORY A ADVERTISING CALCULATION

Category A Expense:	
NW Natural Oregon Proposed Operating Revenue:	$1,083,624,393
*Factor per OAR:	0.125%
Calculation = $1,083,624,393 x .00125 =	$1,354,530
Test Year Number of Customers:	707,022
Per Customer Calculation = $1,354,530/707,022 =	$1.92

Proposed Category A Expense:	
NW Natural Oregon Proposed Operating Revenue:	$1,083,624,393
*Factor per OAR:	0.125%
Proposed Test Year Budget:	$1,378,465
Test Year Number of Customers:	707,022
Per Customer Caluclation = $1,378,465/707,022 =	$1.95
Difference between Company and Staff:	$23,935

*OAR 860-026-0022 Rule = 1/8 of 1% of sales is presumed reasonable

Q. What is your recommendation regarding Category A Advertising expense?

A. Staff proposes to limit the Company's recovery of Category A expense to the amount that is presumed reasonable under OAR 860-026-0022(3)(a), which is $1,354,530 or $1.92 per customer for the Oregon Test Year.

Q. Why do you propose to disallow expense that exceeds the threshold for the rebuttable presumption?

A. As discussed elsewhere in Staff testimony, utility customers are facing significant pressure from escalating costs, including utility costs. NW Natural has not shown that it is appropriate for customers to bear costs for advertising

above the administratively set threshold for presumed reasonableness. Staff expects the utility to be diligent in cost cutting and minimizing given that it has had rate three general rate increases in the last six years.

Q. Please describe your analysis of the Company's proposed advertising expenses for Category B.

A. Category "B" includes legally mandated advertising expenses, which are presumed to be just and reasonable for rate-making purposes, though the presumption is rebuttable.

Q. Please explain your proposed Category B advertising expense.

A. Staff analyzed NW Natural's Category B advertising expense data in its responses as referenced above for Category A advertising expense. Staff confirmed that advertisements were related to safety-related communications. NW Natural plans to expand their website to offer multi-language content and deploy broader multi-language media for the Test Year.

Staff recognizes that the Company's proposed Category B expense is presumed reasonable but believes that the presumption is overcome in this case. For the reasons discussed above, there is no justification for rate recovery of a 22 percent increase in expense from 2023 actuals or an 18 percent increase from the expense allowed in the last GRC.

Given the presumption of reasonableness is rebutted due to the steep increase proposed by NW Natural, Staff recommends determining the Test Year expense for Category B advertising by averaging in the expense for the years before and after the Base Year to smooth out the increase in the Test

Year. This modification results in a Test Year expense of $836,078, Staff recommends an adjustment of ($139,085) to NW Natural's proposed Test Year Category B advertising expense of $975,163.

FIGURE 3. 2025 TEST YEAR CATEGORY B ADVERTISING CALCULATION

Category B Expense	
Year	Oregon Allocated
2022 Actual:	$911,928
2023 Actual:	$802,055
2024 Budget:	$794,250
Average:	$836,078
2025 Test Year:	$975,163
Difference between Company and Staff Proposal:	($139,085)

Q. What is the total adjustment to advertising?

A. Staff proposes adjusting overall advertising expense on an Oregon allocated Test Year by ($163,020).

Docket No: UG 490

Staff/1700
Rossow/11

ISSUE 3. MEMBERSHIPS, DUES, AND DONATIONS

Q. Please explain the Commission's historical treatment of memberships, dues, and donations.

A. The Commission has determined that some expense associated with memberships, dues, and donations to some organizations is not appropriately included in a utility's revenue requirement, primarily because some or all the organizational activities are:[11]

- Not necessary for utility service,
- Primarily to promote the company within the community,
- Not to benefit ratepayers, or
- Not recoverable in rates if done by the utility itself.

Additionally, Commission policy does not require ratepayers to pay for causes that they do not necessarily support. [12]

To limit the amount of ratepayer funding of activities that fall within the categories listed above, Commission practice is to exclude membership expenses related to economic development and civic organizations and to exclude a certain percentage of membership costs for trade organizations. With respect to other organizations, Staff follows Commission precedent by disallowing all memberships or dues unless the utility can present a convincing argument that the membership is necessary for utility service or otherwise to benefit ratepayers.

[11] See Order No. 87-406.
[12] See OPUC Order No. 87-406 at 40-41, Order No. 91-186 at 16, and Order No. 09-020 at 20-21.

Docket No: UG 490

Staff/1700
Rossow/12

Q. Did NW Natural propose an adjustment to its Test Year to remove memberships, dues, and donations?

A. No.

Q. Please explain your analysis for the memberships, dues, and donations adjustment.

A. Staff analysis included the review of NWN's memberships and dues expenses listed in Standard Data Request 90.

Q. What was the result of Staff's analysis for memberships, dues, and donations?

A. Staff's adjustment utilizes a list of memberships from NW Natural's response to Data Request No. 90. Staff identified $57,120 expense for memberships related to economic development and civic organizations in NWN's Oregon allocated Base Year. Next, Staff applied All-Urban CPI inflation factors of 2.7 percent and 2.0 percent in 2024 and 2025, respectively, resulting in an Oregon escalated Test Year adjustment to memberships of ($59,835).

Staff also identified $1,611,788 expense for memberships related to national and regional industry trade organizations in NWN's Base Year. Staff removed 25 percent of the expense to the Base Year in the amount of $402,947. Staff applied All-Urban CPI inflation factors mentioned above, resulting in an Oregon escalated Test Year adjustment to memberships of ($422,103).

Q. What is Staff's total adjustment to memberships, dues, and donations?

A. Staff's analysis results in an escalated Oregon allocated Test Year adjustment to memberships of ($481,938).

Docket No: UG 490

Staff/1700
Rossow/14

ISSUE 4. MEALS AND ENTERTAINMENT, AWARDS, GIFTS, AIRFARE, LODGING, AND TRAVEL

Q. Please explain the Commission's historical treatment of O&M non-payroll discretionary expenses.

A. O&M non-labor discretionary expenses include expenses for items such as awards, food, gifts, meals, and entertainment. In Docket No. UE 197, the Commission clarified its policy that expenses for meals and entertainment, office refreshments, catering, gifts, and awards are discretionary and should be shared equally by customers and shareholders.[13] Accordingly, a 50 percent sharing of such expenses between customers and shareholders is routinely recommended by Staff. In addition, Staff recommends disallowance of O&M non-payroll expenses that are imprudent or excessive or do not benefit Oregon regulated utility operations at a transactional level.

Q. Did the Company propose an adjustment to its Test Year to remove meals and entertainment and awards expenses?

A. No.

Q. Please describe your analysis for the meals and entertainment O&M non-payroll expenses.

A. Staff reviewed NW Natural's Direct Testimony, NWN's Standard Data Response No. 57, NWN's response to Data Request Nos. 442 – 455, and NWN response Data Request No. 201 Attachment 3, which includes meals

[13] *See In the* Matter *of Portland General Electric Company Request for a Rate Revision*, Docket No. UE 197, Order No. 09-020, p. 16 (January 22, 2009).

and entertainment, awards, gifts, refreshments, airfare, lodging and travel type of expenses, to identify any O&M non-payroll discretionary expenses that appear to be excessive or not related to the provision of safe and reliable energy to customers. In the Company's response to Data Request No. 201 Attachment 3, the Company provided O&M non-payroll transactional expenses in Excel format. The accounting data includes category fields, account number, cost element numbers, FERC accounts, transaction descriptions, source descriptions, and currency amount.

From this workbook, Staff searched through the data to aid in Staff's analysis of O&M non-payroll discretionary expenses. Staff filtered the data by transaction description and account number name. Some of the selected expenditure types were meals and entertainment, awards, gifts, refreshments, airfare, lodging, and travel.

Staff reviewed the selected expenditure types mentioned above to determine whether they benefit customers or are discretionary and should be shared between customers and shareholders according to Commission policy. Items Staff found to have no benefit to customers, Staff excludes at 100 percent. Those expenses Staff believed benefitted both customers and shareholders, Staff disallowed at 50 percent. Once Staff determined the disallowance based on 2023 dollars, Staff adopted the All-Urban CPI inflation factors. The inflation factors reflect assumed inflation of 2.7 percent and 2.0 percent in 2024 and 2025, respectively.

Q. Would you please explain your adjustment?

A. Yes. For example, within the selected expenditure types, Staff noted transactions related to expenses described as: meals and entertainment, awards, gifts, refreshments, and retreat at Skamania Lodge that Staff recommends excluding 50 percent.

Q. What was the result of Staff's review for these expense types?

A. After reviewing O&M non-payroll expenses, Staff identified 2023 total Company Base Year expense of $691,631 with an associated Oregon allocated Base Year amount of $597,759. After removing 50 percent of the allocated Base Year results in an amount of $298,880. Next Staff applied the All-Urban inflation factors mentioned above, resulting in an adjustment to the Oregon Test Year allocated amount of ($313,088).

Q. Is there an issue relating to airfare?

A. Yes. In the Company's response to Staff data request No. 447, it was revealed that NW Natural inadvertently included first class airfare totaling a Base Year amount of $36,257. Staff applied All-Urban CPI inflation factors mentioned above, resulting in an Oregon escalated Test Year adjustment to airfare of $37,981. The Company will correct the revenue requirement in their reply testimony to exclude the total of these transactions.

Q. What is Staff's total meals and entertainment adjustment?

A. Staff's total adjustment is an adjustment of ($351,069) to O&M non-labor discretionary expenses.

Docket No: UG 490

Staff/1700
Rossow/17

SUMMARY FINDINGS AND RECOMMENDATIONS

Q. Please summarize your findings and recommendations.

A. Staff's recommendations are as follows:

- Issue 1 (Political Activities) – a total adjustment of ($11,572) to the Oregon allocated Test Year expense for FERC Account 921;
- Issue 2 (Advertising) – a total adjustment of ($163,020) to the Oregon allocated Test Year for FERC Account 909;
- Issue 3 (Memberships, Dues, and Donations) – a total adjustment of ($481,938) to the Oregon allocated total Test Year expense for FERC Accounts 832-932; and
- Issue 4 (Meals and Entertainment, Awards, Gifts, refreshments, Airfare, Lodging, and Travel) – a total adjustment of ($351,069) to the Oregon allocated total expense for FERC Accounts 816-936. Additionally, the Company will update its revenue requirement in its reply testimony relating to first class airfare for a total Oregon Test Year amount of $37,981.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 490
WITNESS: PAUL ROSSOW

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1701

Witness Qualifications Statement

April 18, 2024

Docket No. UG 490

Staff/1701
Rossow/1

WITNESS QUALIFICATIONS STATEMENT

NAME: Paul Rossow

EMPLOYER: Public Utility Commission of Oregon

TITLE: Utility Analyst
Rates, Safety and Utility Performance Program

ADDRESS: 201 High Street SE Suite 100
Salem OR 97302-1166

EDUCATION: Professional Accounting and Computer Application Diplomas, Trend College of Business 1987

EXPERIENCE: I have been employed with the Public Utility Commission of Oregon as a Utility Analyst since October of 2002. Current responsibilities include research issues relating to energy utilities. I have actively participated in regulatory proceedings in Oregon, including UE 147, UE 167, UE 170, UE 179, UE 180, UE 197, UE 210, UE 213, UE 215, UE 217, UE 233, UE 246, UE 262, UE 263, UE 283, UE 335, UE 374, UE 394, UE 399, UE 435, UG 152, UG 153, UG 181, UG 186, UG 201, UG 221, UG 246, UG 284, UG 344, UG 347, UG 388, UG 389, UG 390, and UG 435.

I have attended the Utility Rate School sponsored by the Committee on Water of the National Association of Regulatory Utility Commissioners in May of 2005 and the Institute of Public Utilities sponsored by the National Association of Regulatory Utility Commissioners at Michigan State University in August of 2005.

CASE: UG 490
WITNESS: PAUL ROSSOW

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1702

Non-Confidential Data Responses in Support Of Opening Testimony

April 18, 2024

NW Natural®

Rates & Regulatory Affairs

UG 490

Request for a General Rate Revision

Data Request Response

Request No.: UG 490 OPUC DR 341

Please discuss the Company's current expenses for political activities/public affairs. Does the Company propose any approaches or budgeting that is new or different from the last two general rate cases.

Response:

NW Natural, like other utilities in Oregon, engages in public affairs matters on behalf of our customers and are included in the revenue requirement for UG 490. This includes working with a local jurisdiction on obtaining permits for utility construction projects, language updating franchise agreements or right of way ordinances, and safety and security efforts within our jurisdictions.

Political expenses are not requested for recovery. This includes incidental expenses, like mileage, associated with any political activities.

In our prior rate case, the allocations for political activities for the Government and Community Affairs team were based on historical allocations used by the Company. In the current case, the Government and Community Affairs team have recorded exception time for political activities in the base year, and the Company is not seeking recovery of those costs in the Test Year. The Company included information about timekeeping and accounting to differentiate time spent on political activities versus general utility activities such as safety and security efforts within our jurisdictions in NW Natural/1200, Williams.

Docket No. UG 490

Staff/1702 Rossow/2

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 342

Are these activities included in the revenue requirement for UG 490? If yes, please identify FERC Accounts that contain these expenditures.

Response:

The heading for this Staff data request is: **RE: Political Activities/Public Affairs**

Please see the Company's response to UG 490 OPUC DR 341.The public affairs activities described in UG 490 OPUC DR 341 are included in the revenue requirement for UG 490 and are included in FERC 921, as such activities include "informational engagement and education for local governments for which ratepayer support is appropriate." UG 435, Order No. 22-388 (entered October 24, 2022), page 24.

As it relates to NW Natural/1200, Williams, the described political lobbying activities or activities intended to influence that are tracked through exception reporting are not included in the revenue requirement for UG 490. As described in NW Natural/1200, Williams these activities are charged to FERC 426.4 – Expenditures for certain civic, political, and related activities. FERC 426.4 is not included in the revenue requirement and is considered "below the line".

CASE: UG 490
WITNESS: PAUL ROSSOW

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1703

Non-Confidential Memberships, Dues, and Donations Work Paper (Filed In Electronic Format)

April 18, 2024

CASE: UG 490
WITNESS: PAUL ROSSOW

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1704

Non-Confidential Data Response in Support Of Opening Testimony

April 18, 2024

Docket No. UG 490 Staff/1704 Rossow/1

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 447

If NW Natural is seeking rate recovery for first class airline tickets in docket UG 490, please provide:

a. the amount of each transaction on a system and Oregon allocated basis,
b. justification for purchasing first class airline tickets,
c. the FERC account number, and
d. Oregon allocation factor.

Response:

The policy of the Company is not to request cost recovery for expenses related to the incremental difference between the cost of first/business class airline tickets and base-fare airline tickets.

Through our review of the airfare transactions in development of this response, it appears that there are certain transactions that were not coded correctly and the incremental cost between base fare and first-class fare was inadvertently included in Base Year. Refer to Confidential UG 490 OPUC DR 447 Attachment 1 for a summary. The Company will correct the revenue requirement in our reply testimony to exclude the total of these transactions in the Base Year of $36,257 on an Oregon-allocated basis.

Please also see the Company's response to UG 490 Coalition DR 446.

CASE: UG 490
WITNESS: PAUL ROSSOW

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1704

Non-Confidential Meals and Entertainment Work Paper (Filed In Electronic Format)

April 18, 2024

CASE: UG 490
WITNESS: ERIC SHIERMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1800

Opening Testimony
Marginal Cost, Rate Spread and Rate Design

April 18, 2024

Docket No: UG 490

Staff/1800
Shierman/1

Q. Please state your name, occupation, and business address.

A. My name is Eric Shierman. I am a Senior Utility Analyst employed in the Energy Resources and Planning Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/1801.

Q. What is the purpose of your testimony?

A. This testimony reviews NWN's proposals on marginal cost, rate spread, and rate design and offers Staff's recommendations.

Q. Did you prepare any exhibits for this docket?

A. Yes, Exhibit Staff/1801 is my witness qualification statement.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Marginal Cost 2
Issue 2. Rate Spread 6
Issue 3. Rate Design..... 16

Docket No: UG 490

Staff/1800
Shierman/2

ISSUE 1. MARGINAL COST

Q. What is the Long Run Incremental Cost (LRIC) Study and what is its goal?

A. Estimates of the NWN LRIC is developed through a study and identifies the different costs to serve each rate schedule. Utilities do not keep granular accounting records of costs by customer type. As such, the LRIC uses the replacement costs (by assuming all inputs are variable) of the entire system to attribute costs to particular rate schedules. The costs are functionalized by dividing them into several cost categories and then attributed to different customer classes by how the customer class uses the facilities.

For example, distribution mains are large pipes utilized by all customer classes to deliver gas for use. These can be broken down into "system mains" and "main extensions" based on their size and position in the distribution system. Since a major cost driver of these large-diameter mains is meeting peak demand, a customer class's burden to pay for these system mains should correlate to each customer schedule's own peak day load. The higher the peak day load for a schedule, the more that schedule is requiring the Company to invest in system mains to meet peak demand.

Once each cost category is broken down and each customer class's cost causation has been identified, ratios are used to allocate the revenue requirement for each designated functional category.[1] Ultimately, the study compares what portion of costs each customer class is currently paying to what

[1] See UG 490 - Exh. 1801 - WP6 - Long-Run Incremental Cost Study (LRIC) Model.

they should be paying based on the above noted allocation method. This can be used as the basis for cost-based rates, the theory being you should pay for the costs you are causing to the system.

Costs that can be easily divided up are calculated by taking the per-customer average and multiplying by the number of customers in that schedule. The remaining costs are allocated by identifying cost types within each cost category and customer class. Many other considerations often can and do go into rate spread and rate design, but usually the LRIC is a large driving force behind the rates a customer pays.

Q. Has the Company's LRIC methodology changed since the last rate case?

A. Yes. The Company made two changes based on Staff's feedback in UG 435.[2] The Company modified the Maximum Daily Demand Value (MDDV) calculation for design day load factor development, which accounts for changing incremental customer counts across time, in response to Staff's feedback that nonresidential customers going in and out of business gave the false appearance of lower use per customer. Second, the Company modified its system core main allocation to calculate weighted peak day deliveries for all rate schedules as a basis for core main cost assignment by allocating interruptible customers a 50 percent credit for system core main allocation, down from 100 percent.[3] In UG 435, Staff noted that these customers do use

[2] NW Natural/1800, Wyman/32-33.
[3] Id.

system capacity, so weighting them with no marginal system core main cost underestimates their marginal cost.[4]

Q. Do you believe that the Company implemented Staff's feedback effectively?

A. Based on Staff's inspection of the Company's LRIC workpapers, it appears to Staff that this feedback was implemented effectively. Staff has no additional feedback regarding the Company's LRIC at this time but looks forward to reading other parties' testimony and perhaps updating its position.

Q. What did the Company's new LRIC show?

A. The LRIC shows nearly half of customers classes, including residential customers, are paying closer to parity than was the case in UG 435. [5] The customers paying below parity are RS 2 Residential, RS 3 Commercial, and RS 27 Dry-Out. Table 1 displays the parity ratios at present rates.[6]

Table 1. LRIC Study Parity Ratio at Present Rates, by Rate Schedule

RATE SCHEDULE	02R	03C	03I	27R	31CSF	31CTF	31ISF	31ITF
LRIC Study Determined Parity Ratio	**0.96**	**0.95**	**1.21**	**0.82**	**1.66**	**1.95**	**1.63**	**2.34**
RATE SCHEDULE	32CSF	32ISF	32CTF	32ITF	32CSI	32ISI	32CTI	32ITI
LRIC Study Determined Parity Ratio	**1.61**	**1.91**	**2.22**	**1.65**	**1.30**	**1.46**	**2.64**	**1.25**

[4] NW Natural/1800, Wyman/43-44.
[5] NW Natural/1800, Wyman/57-58.
[6] Table from UG 490 NW Natural/1800, Wyman/57. Rate Schedule 2 (Residential), Schedule 3 (Commercial), 27 (Residential Heating Dry-Out Service), Schedule 31 (Non-Residential Firm Sales and Firm Transportation Service), Schedule 32 (Large Volume Non-Residential Sales and Transportation Service).

A parity ratio of one is equal parity between total LRIC for a class of customers and total revenues for that class given revenue from rates charged to that class of customers. A ratio under one means the customer class is paying less than its LRIC and a ratio greater than one means the customer class is paying more than its LRIC.

Q. Does Staff have adjustments to NWN's assessment of marginal cost?

A. Staff has no adjustments at this time but may after reviewing other parties' testimony.

Docket No: UG 490

Staff/1800
Shierman/6

ISSUE 2. RATE SPREAD

Q. Please describe rate spread.

A. Rate spread is the practice of allocating a company's revenue requirement to its various customer classes. Doing so effectively should balance concerns of economic efficiency, equity and energy justice concerns, and rate shock.

Q. How does one properly balance these potentially conflicting concerns?

A. In general, rate spread allocations begin by conducting a LRIC study to determine the optimal way to allocate costs between the Company's various customer classes. As described in this testimony, the LRIC provides valuable insight into the costs to serve each of the Company's customer subgroups, which can be compared to the revenues generated by each subgroup. While there is often disagreement in methodology that an LRIC employs, one goal of rate spread is to align the revenue earned from each customer class with the costs to serve each customer class according to the LRIC. This is often referred to as "moving towards parity."

If the LRIC does show a need to move towards parity from current rates, it is best practice to make the move towards parity deliberate enough that customers can properly adapt to these new different rates and to signal that they are still operating under a regulatorily stable environment. This is often referred to as avoiding rate shock or inequitable results from a policy perspective—an example of which may be significantly increasing the rates of one customer class so that other customer classes may have a rate decrease.

Finally, the Commission has been statutorily authorized to consider equity and environmental justice concerns as factors in rate spread. A move towards parity may put costs on environmental justice or underserved groups in a way that may not be optimal from a socio-economic perspective. Further, to the extent that current modeling approaches employed with the LRIC look only at costs to the system, disparities in the system benefits received by different customer groups remain unaccounted for.

These various concerns of lack of modeling clarity, rate shock, and awareness of environmental justice concerns make it so every rate spread methodology has tradeoffs and selecting an optimal rate spread methodology must balance all these concerns.

Q. How does the Company's proposal align with parity considering what the LRIC shows with respect to cost causation?

A. NWN's proposal brings each rate class to the parity ratios that are closer to 1 than they would otherwise be with no change to the current rate spread. Table 2 below shows the current parity ratios of the classes discussed above and the parity rations that would result from the Company's proposal.

Table 2: NWN's Proposed Change in Parity Ratios

Schedule	Current Parity Ratio	Proposed Parity Ratio	Change
02R	0.96	0.97	0.01
03C	0.95	0.96	0.01
03I	1.21	1.13	(0.08)
27R	0.82	0.86	0.04
31CSF	1.66	1.54	(0.12)
31CTF	1.95	1.73	(0.22)
31ISF	1.63	1.51	0.12)
31ITF	2.34	2.07	(0.27)
32CSF	1.61	1.50	(0.11)
32ISF	1.91	1.70	(0.21)
32CTF	2.22	1.97	(0.25)
32ITF	1.65	1.47	(0.18)
32CSI	1.3	1.21	(0.09)
32ISI	1.46	1.36	(0.10)
32CTI	2.64	2.34	(0.30)
32ITI	2.64	1.11	(1.53)

Q. Does Staff agree with the use of LRIC as a basis for the Company's rate spread?

A. Staff supports the use of LRIC as a baseline resource for rate spread proposals. As a general matter, pricing and customer cost allocations should reflect long-run-incremental cost-causation as much as possible.

A strict LRIC-based target allocation of marginal costs to the various customer schedules would be the outcome of allocating shares of embedded cost categories to customer schedules strictly in proportion to their respective

shares of LRIC costs for the respective categories. However, as the Company testifies, relying entirely on parity may result in very large rate increases for many customers and perhaps inadvertently signal rate volatility.[7] Staff agrees with the Company's position that rate spread must balance the interests of rate equity and rate volatility with the results of an LRIC. However, at times these priorities can be at odds with each other.

Evolutions to the rate spread cost allocation from the LRIC can avoid the burden of imposing an increase to a particular customer schedule that is unacceptably out of line with the overall increase and avoid allowing some schedules to receive a rate decrease in the context of a significant increase being imposed on most of the other customer schedules. This "deviation" appears particularly appropriate in the context of the Company's UG 490 proposal, such that the results of the LRIC results would implement an increase relative to total revenues of 21.0 percent for Schedule 2 Residential, 19.5 percent for Schedule 3 Commercial, and 32.1 percent for Schedule 27 Dry-Out rate classes while the large commercial, industrial, and transportation rate classes would receive overall rate decreases.[8] As a percentage of marginal revenues, the disparity appears even more dramatic. Table 3 presents the percentage change of marginal revenues to bring each rate class to parity according to the Company's LRIC.

[7] NW Natural/1800, Wyman/81.
[8] NWN/1800, Wyman/82.

Table 3: Percent of Margin Increase for Each Customer Class

Rate Schedule	Average	02R	03CSF	03ISF	27R	31CSF	31CTF	31ISF	31ITF
Target Increase (LRIC)	29.30%	34.2%	35.8%	6.5%	57.0%	-22.0%	-33.7%	-20.5%	-44.7%
Rate Schedule	**32CSF**	**32ISF**	**32CTF**	**32ITF**	**32CSI**	**32ISI**	**32CTI**	**32ITI**	**33T**
Target Increase (LRIC)	-19.7%	-32.4%	-41.8%	-21.8%	-0.7%	-11.3%	-51.1%	3.5%	0.0%

While such a spread would result in rate parity across the classes, the impact to customers in terms of price signals, affordability, and reasonableness would be substantial. Further, as highlighted by the Company, the Commission has provided some precedent on how it may regard mismatches between rates derived from the LRIC and proposed rate changes, stating, as noted earlier, that it is not inclined to raise some rates while lowering others without compelling evidence that immediate action is warranted. [9]

Q. How has the Company proposed to balance the concerns of moving towards parity, mitigating rate shock, and ensuring no customer receives a rate decrease while others receive a rate increase?

A. The Company proposes to balance these concerns by first applying a cap to the proposed increases relative to margin according to the LRIC to Schedule 2, Schedule 3, and Schedule 27. The Company chose to cap the rate increase to each of these customer classes to no more than a multiplier value tied to the

[9] Id.

average increase of 29.3 percent presented in Table 3. The multipliers were 1.04, 1.05, and 1.22 for Schedules, 2, 3, and 27, respectively.[10]

For the remainder of the revenue requirement increase, the Company applies a rate increase floor that allocates half of the increase in margin revenues to all customers whose parity ratio is over 1.75 percent. The remainder of costs are spread to all remaining customer classes on an equal percent of margin basis.[11]

Q. What is the effect on total revenue requirement of the Company's rate spread proposal?

A. Table 4 presents the total revenue requirement increase per schedule and the ratio of the percentage increase per schedule relative to the average increase.

[10] NW Natural/1802.
[11] NW Natural/1800, Wyman/84-85.

Docket No: UG 490

Staff/1800
Shierman/12

Table 4: Total Proposed Rate Increase by Schedule

Schedule	Rev. Req. Increase	% Increase	Ratio of Increase
02R	$ 109,872,388	18.8%	1.13
03C	$ 34,870,187	16.8%	1.01
03I	$ 488,805	9.6%	0.58
27R	$ 212,003	20.2%	1.21
31CSF	$ 2,041,479	9.0%	0.54
31CTF	$ 167,028	14.7%	0.88
31ISF	$ 704,711	7.3%	0.44
31ITF	$ 22,982	14.7%	0.88
32CSF	$ 2,848,675	7.2%	0.43
32ISF	$ 537,107	3.6%	0.22
32CTF	$ 145,599	14.7%	0.88
32ITF	$ 983,401	14.7%	0.89
32CSI	$ 521,566	3.9%	0.23
32ISI	$ 607,749	3.6%	0.22
32CTI	$ 75,413	14.7%	0.88
32ITI	$ 810,559	14.7%	0.88
33T	$ -	0.0%	0.00
Total	$ 154,909,651	16.7%	1.00

Q. Why does Staff believe that it is important to present the rate increase for each customer class as a ratio to the percent of the total rate increase – including gas costs?

A. Staff and other parties are proposing adjustments to the Company's proposed revenue requirement. As an example, Staff in its opening testimony recommends adjustments to the Company's revenue requirement totaling between ($36 million) and ($42 million) depending on the Return on Equity (ROE) assumptions used.[12] Discussing rate spread proposals on a total dollar or a percentage increase basis becomes difficult as agreements or Commission orders may change the overall size of the revenue requirement

[12] See Staff/200.

pie that must be split among the rate classes. Therefore, Staff believes it to be easier and more appropriate to instead present its rate spread recommendations as a ratio to the average percentage increase and a set of guidelines to fairly allocate rate spread as the case evolves.

Q. Does Staff find the Company's proposed rate spread to be fair?

A. No. While the Company does move towards parity and the ratio of cost increases relative to the average is relatively small, Staff does not believe that concerns about the relatively large rate increases are properly addressed by the proposed spread of incremental revenue requirement. As can be seen above, various industrial schedules have received as little as 22 percent of the average increase while other customer schedules receive up to 121 percent of the average increase. Given the overall size of the company's proposed increase to revenue requirement, Staff believes it would be preferable to slow the move towards parity and spread rates more evenly across customer classes.

Q. How does Staff propose moving towards parity while more evenly spreading the rate increase across customer classes?

A. Staff proposes to use the Company's current rate spread as a starting point and implement a floor of 75 percent of the average percentage increase when determining the lowest possible rate spread allocation to each schedule. In effect, this raises the allocated revenue requirement for Schedule 31 and Schedule 32 customers. Any revenue requirement added to these schedules

will then be taken away from the three schedules that were given a cap in the Company's initial rate spread methodology.

This means that the incremental revenue requirement to Schedule 2 and Schedule 27 customers is lowered, but still remains above the average percentage increase. Staff has expressed concerns about relying solely on the LRIC for determining parity, and Staff believes that this more optimally balances the pursuit of parity based on the LRIC with concerns about customers experiencing relatively large rate increases.

Q. Please explain Staff's rationale for this proposal.

A. Staff has long argued that in the face of exceptional overall rate increases a narrower rate spread should be adopted.[13] While the LRIC is informative for determining rate spread, Staff argues that a scenario in which some rate schedules experience nearly a 19 percent rate increase, while others see only a 4 percent increase,

is inequitable.

Q. What is the effect of Staff's adjustment to the Company's proposed rate spread model?

A. The rate spread under Staff's proposed method is contained below in Table 5. For ease of presentation, Staff presents this proposal using the Company's filed proposed revenue requirement rather than Staff's proposed revenue requirement presented in the testimony of Staff Witness Luz Mondragon in Staff Exhibit 200. For scale, Staff proposes a total of ($36 million) to

[13] For a recent example of this see UE 426 Staff/1500, Stevens/37.

($42 million) in adjustments to the Company's requested revenue requirement.[14]

Table 5. Staff's Proposed Rate Spread

Schedule	Rev. Req. Increase	% Increase	Ratio of Increase
02R	$ 102,416,260	17.52%	1.05
03C	$ 34,874,898	16.80%	1.01
03I	$ 635,517	12.49%	0.75
27R	$ 184,159	17.52%	1.05
31CSF	$ 2,817,832	12.49%	0.75
31CTF	$ 167,028	14.74%	0.88
31ISF	$ 1,203,584	12.49%	0.75
31ITF	$ 22,982	14.74%	0.88
32CSF	$ 4,955,681	12.49%	0.75
32ISF	$ 1,848,231	12.49%	0.75
32CTF	$ 145,599	14.73%	0.88
32ITF	$ 983,401	14.74%	0.89
32CSI	$ 1,673,401	12.49%	0.75
32ISI	$ 2,095,108	12.49%	0.75
32CTI	$ 75,413	14.74%	0.88
32ITI	$ 810,559	14.73%	0.88
33T	$ 0	0.00%	0.00
Total	$ 154,909,651	16.70%	1.00

[14] See Staff/200.

Docket No: UG 490

Staff/1800
Shierman/16

ISSUE 3. RATE DESIGN

Q. Please summarize the Company's rate design proposals?

A. NWN proposes three changes to the monthly charge:

- Increase the basic charge for residential single-family customer from $8 to $10.[15]
- Implement a bifurcated basic charge that keeps the multi-family basic charge at $8.[16]
- Create a new monthly charge premium of $16.25 for all new customers to the Company's system that would be added onto the Company's basic charge proposal.[17]

Q. Why is a monthly charge generally included in a residential rate design?

A. The monthly charge is the price a customer pays in a month regardless of the amount of energy consumed. If one were to set rates purely on short-run cost causation, the basic charge would be used to recoup the Company's fixed costs that do not vary with a customer's natural gas usage.

However, Staff notes that setting a basic charge purely on the merits of assumed Company fixed costs comes with some notable shortcomings. First, studies of the fixed per-customer costs can vary dramatically depending on the assumptions used by the modeler. Staff has discussed these general concerns about the LRIC in this testimony as well as many other proceedings and notes that LRIC is long run where all inputs are variable while short-run

[15] NW Natural/1800, Wyman/60.
[16] NW Natural/1800, Wyman/73.
[17] NW Natural/1800, Wyman/77.

allows for fixed costs. In the short run, main and distribution pipes costs are fixed and no reinforcements are needed, while in the long-run all of the Company's facilities are variable. Second, a high basic charge has the potential to exacerbate existing energy equity and affordability issues for certain communities by improperly saddling low-income and low-usage customers with higher overall bills than they would otherwise have. While it is difficult to make this determination absent better data on how natural gas usage varies with income, Staff believes that a key consideration to changes to rate design is the disproportionate impacts the changes may have to environmental justice communities. Staff discusses these and other energy justice concerns associated with the Company's basic charge proposal further in Staff/300.

Q. How do the Company's proposed monthly charges align with the customer and fixed costs that the Company modeled?

A. The Company's LRIC Study in this rate case models the per-customer single family fixed cost of service at approximately $37 per month.[18] Based on the Company's study on multi-family cost of service, the Company expects the multi-family fixed cost of service to be between $9 and $15, depending on the capital cost payback assumptions used.[19]

[18] NW Natural/1800, Wyman/60.
[19] See Workpaper 3 to NW Natural Exhibit 1800.

Q. Based on this analysis, does Staff agree with the Company's proposal to bifurcate the basic charge into a single-family and multi-family charge?

A. Yes. Staff appreciates the Company carrying out the thorough analysis following our recommendation in UG 435.[20] NWN has studied the cost differences and confirmed the two-dollar credit for multifamily residential customers is justified by cost savings from operational efficiencies.[21] While the proper methodology to study the fixed cost of service is sensitive to the assumptions made in the study, Staff is convinced that the Company's modeling is adequate to justify a bifurcated basic charge even if one were to view it through a cost causation lens. Staff further notes that it expects a bifurcated basic charge to have positive equity impacts, as low-income Oregonians within NW Natural's service territory are generally more likely to live in multi-family dwellings.

Q. Does Staff agree with the Company's proposal to raise the monthly charge for single-family residential customers from $8 to $10?

A. Staff takes no issue with the increase to the basic charge at this time. Staff notes that NWN has among the lowest monthly charge among peer utilities.[22] That being said, looming affordability concerns across many utility customers gives reason to consider this proposed increase directly through the lens of

[20] See Docket No. UG 435, OPUC Staff, Opening Comments, April 22, 2022, Staff/1300 Scala/48.
[21] NWN/1800, Wyman/72.
[22] NWN/1800, Wyman/60.

customer impacts. As such, Staff may update its views following the Energy Justice Issues Public Workshop and its review of intervenors' testimonies.

Q. What is the Company's proposal for new residential customers?

A. NWN proposes to charge new premise residential customers a $16.25 premium over existing customers in the monthly basic charge. In effect, this will raise the monthly charge to $26.25 for single family customers and to $24.25 for multi-family customers who join NW Natural's Oregon gas system as a new premise customer on or after November 1, 2024. As a result, residential customers would have four different monthly charges under NWN's proposal. These four proposed monthly charges can be seen in Table 6.

Table 6. NWN's Proposed Residential Monthly Charges

Density	Old Customer	New Premise Customer
Single Family	$10	$26.25
Multi-Family	$8	$24.25

Q. What is the Company's stated reason for this higher basic charge for new premise residential customers?

A. NWN's load forecast finds new premise customers have, on average, a use per customer (UPC) roughly 210.8 therms lower than existing customers.[23] The Company states that it wants to collect a more equitable amount of revenue from new premise customers as compared to revenue collected from existing customers as part of its "responsible growth strategy". With lower margins from new premise customers, the Company seeks to raise revenue from new

[23] NW Natural/1800, Wyman/77.

premise customers in the fixed monthly charge to recoup lost revenue from lower volumetric sales.

Q. Does Staff support the NWN proposal?

A. No. Staff believes that issues related to new customers are more appropriately addressed by the Company's line extension allowance (LEA) policy and NWN's decoupling mechanism. Staff Witness Dr. Curtis Dlouhy discusses Staff's issues with the Company's LEA proposal in Staff Exhibit 900, which are not just limited to the Company's new premise basic charge. Further, issues with variances in volumetric sales are best solved by the Company's decoupling mechanism rather than a blanket charge that applies to all new customers. Proposals to modify the decoupling mechanism are addressed in Staff Witness Dr. Bret Stevens' testimony in Staff Exhibit 1900.

Q. Does Staff believe that a new premise basic charge is equitable?

A. Neither Staff nor the Company have a strong grasp of the demographics that would be subject to a new premise basic charge. Absent this knowledge, it is impossible for Staff or stakeholders to understand whether the financial impacts and cost shifting that result from this proposal would ultimately benefit or harm marginalized communities. Our concerns about LEA policy and decoupling aside, Staff believes that components justified as part of the Company's larger business or "responsible growth strategy" should be explored in a comprehensive planning setting such as an IRP where stakeholders can review the Company's intended trajectory more holistically

and have an opportunity to express concerns or share their expertise before such a sweeping change is proposed in a general rate case.

Q. Does Staff believe that it is fair and just rate design to distinguish residential customers by their status as a new customer or existing customer?

A. No. Staff prefers this to be handled through the decoupling mechanism which has different revenue per customer targets based on whether the customer is "new" or existing. The decoupling mechanism is designed to recover the Company's fixed cost regardless of variable consumption. This mechanism decreases the risk that the Company under-recovers these costs. NWN is proposing to differentiate between existing and new customers in its decoupling mechanism calculation, however Staff sees the rationale for this proposal as sufficiently different from the rationale for the new premise basic charge.

The decoupling mechanism proposal is meant to address an issue that is dependent on the customer connection date. In particular, Staff's decoupling mechanism proposal is accounting for the fact that new premise customers tend to consume less than existing customers *and* that their lower consumption is not taken into account when NWN calculates its decoupling revenues between rate cases. Staff argues that it is the combination of these issues that makes the decoupling proposal appropriate.

Q. Does Staff believe that the Company's LEA proposal and new premise basic charge send a fair signal to new customers?

A. No. Staff notes that in spite of the Commission's decision to incrementally decrease the LEA each year in UG 435 to under $1000, the Company has proposed an allowance as high as $3700 for the lowest usage new customers.[24] Taken in a vacuum, a new customer may choose to build natural gas into their home based on the financial incentives from the generous allowance. However, the Company's proposal to recover a higher fixed charge from new customers would reduce the financial benefit from the LEA.

Staff is concerned a new customer will be more likely to see a generous LEA than to notice the additional basic charge for new premises customers in the Company's tariffs for residential customers. Therefore, Staff believes that this structure of a large LEA and new premise fixed charge could be somewhat deceptive. In effect, this higher up-front allowance and higher monthly fixed charge acts like a loan to connect to the Company's natural gas system, but there is no guarantee the customer is aware they are paying for the benefit of the loan with a higher fixed charge than existing customers.

Q. Does this conclude your testimony?

A. Yes.

[24] NW Natural/2000, Kravitz – Therrien/23.

CASE: UG 490
WITNESS: ERIC SHIERMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1801

Witness Qualifications Statement

April 18, 2024

Docket No. UG 490

Staff/1801
Shierman/1

WITNESS QUALIFICATIONS STATEMENT

NAME: Eric Shierman

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Utility Analyst
Energy Resources and Planning Division

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION: MS Economics; Portland State University; Portland, Oregon
BA Political Economy; Hillsdale College; Hillsdale, Michigan

EXPERIENCE: I have been employed by the Public Utility Commission of Oregon since June 2019. I was previously employed by McCullough Research as a Research Associate for two years.

CASE: UG 490
WITNESS: BRET STEVENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1900

Opening Testimony
Load Forecast, Decoupling, and Rate Base

April 18, 2024

Docket No: UG 490

Staff/1900
Stevens/1

Q. Please state your name, occupation, and business address.

A. My name is Bret Stevens. I am a Senior Economist employed in the Rates and Telecommunications Section of the Rates, Safety and Utility Performance Program (RSUP) of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/1901.

Q. What is the purpose of your testimony?

A. I discuss and review several issues in Northwest Natural's (NWN) general rate case. This includes NWN's Test Year load forecast, decoupling, and the calculation of rate base for purposes of establishing the return component of NWN's revenue requirement.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Load Forecasting 2
Issue 2. Decoupling 20
Issue 3. Rate Base Calculation 25
Summary 26

Q. Could there be changes or updates to Staff's position and recommendations?

A. Yes. My testimony represents issues identified to date. My recommendations and issues may change when informed by new data and after reviewing testimony and analysis by other parties.

Docket No: UG 490

Staff/1900
Stevens/2

ISSUE 1. LOAD FORECASTING

Q. Please describe the results of Northwest Natural's (NWN) Test Year load forecast.

A. NWN forecasts an Oregon load of 1,050 million therms in the Test Year. Roughly 40.6 percent, 17.5 percent, and 41.9 percent of this total load is attributable to the residential, small commercial, and industrial & transportation customers respectively.[1]

Q. Please describe NWN's methodology for this forecast.

A. NWN forecasts Test Year load in three steps. First, NWN forecasts usage per customer (UPC) in the Test Year by using an ARIMA model on historical usage, weather, and economic data. This Test Year load is forecasted assuming normal weather in the Test Year based on 25-year climate normals.[2] Second, NWN forecasts Test Year customer counts. This forecast is based on historical regional business and employment growth trends, housing start forecasts, and other economic factors.[3] Lastly, the UPC forecast and customer count forecast are multiplied to create the schedule-wide load forecast.

Q. Does Staff have any major concerns regarding the fundamentals of NWN's load forecast methodology?

A. No, Staff has no major concerns with NWN overall load forecast methodology. In general, Northwest Natural uses industry standard methodologies and is

1 NWN/1801, Wyman/1.
2 NWN/1800, Wyman/6.
3 NWN/1800, Wyman/7.

receptive to feedback regarding model improvements. That said, nearly all econometric models have room for improvement across various metrics.

Q. Does Staff have any proposed changes to NWN's load forecast methodology?

A. Yes. Staff is recommending changes to the load forecast with the intention of improving transparency and model flexibility. Staff is recommending a unique set of changes for each rate class UPC forecast. Staff's recommendations can be categorized as the following:

1. Algorithmically parameterize ARIMA models as baseline with any deviations justified in testimony.
2. Attempt to use non-linear weather terms when applicable and discuss rationale for excluding these terms.
3. Use monthly dummies as opposed to the natural logarithm of the number of weekend and holiday days in each month.
4. Drop variables with very small effects.

Q. Has Staff performed these changes to the forecast?

A. Partially. Staff has estimated regression results for various schedules but has not yet evaluated the impact of these proposed changes on the Company's proposed revenue requirement or rates. Staff is working with the Company to implement these changes and understand the full effect of Staff's recommendation on rates. Staff does not anticipate that these changes will have a large impact on the proposed rates in this case but contends that these changes will improve the accuracy of NWN's load forecast.

Q. Please describe Staff's proposed changes to the residential forecast.

A. Staff is proposing several changes to the residential forecast. First, Staff supports using a (1,1,1) ARIMA model as opposed to NWN's proposed (1,0,0)(0,0,1)[2] ARIMA model. This parameterization was automatically selected using the Hyndman-Khandakar algorithm. Staff also recommends modifying the covariate matrix to include monthly fixed effects to control for seasonality, a squared HDD term to control for non-linear effects of weather, and the exclusion of various weather terms that did not produce meaningful coefficients.

Q. How do Staff's proposed changes affect the residential load forecast?

A. These modifications to the load forecast are largely to help the model be more flexible and help improve interpretability. Staff's changes do improve the fit of the model as measured by the Akaike information criterion (AIC) and Bayesian information criterion (BIC). The distribution of residuals between Staff and NWN's proposed models can be seen below in Figure 1.

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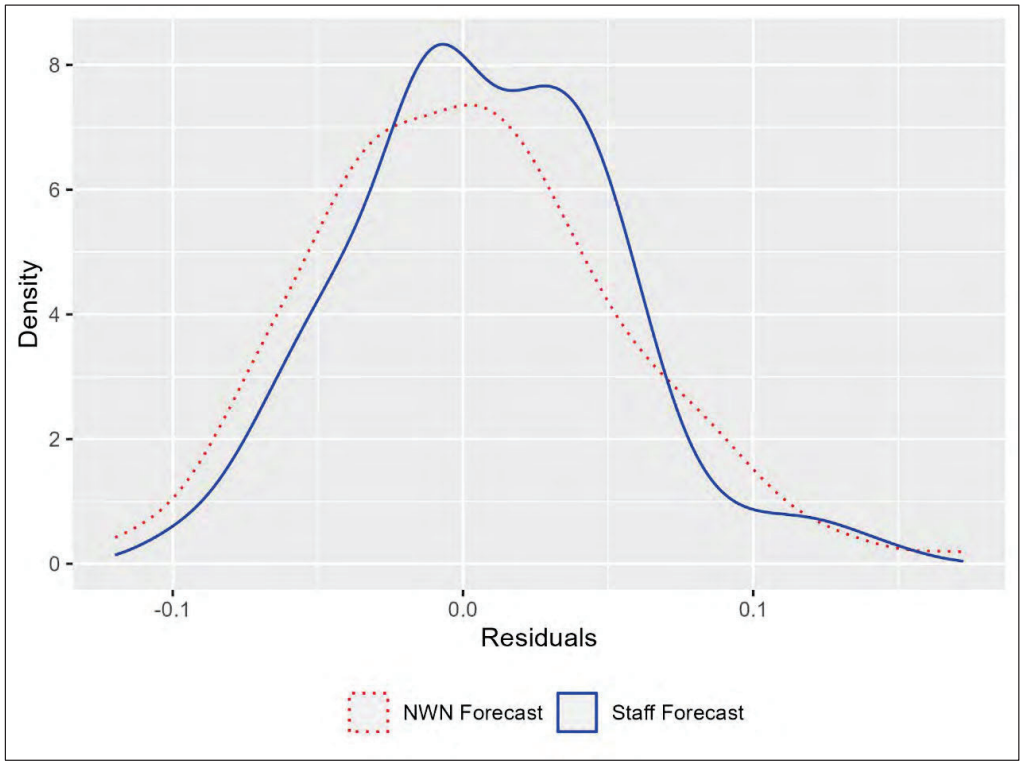
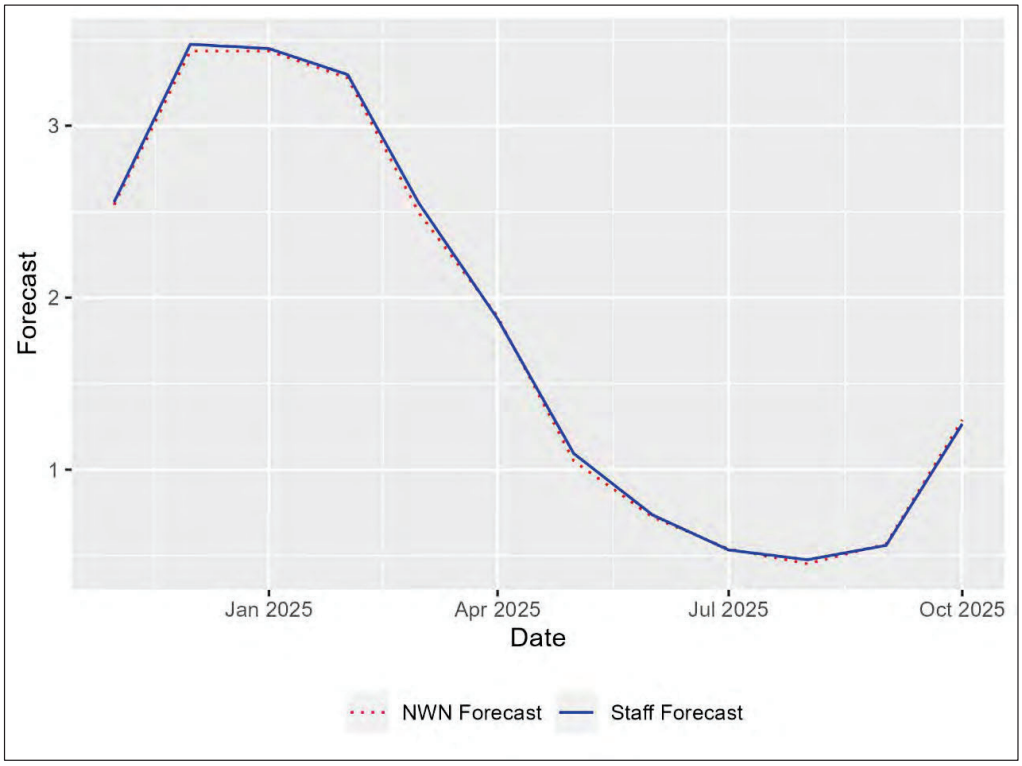
Staff/1900
Stevens/5

Figure 1. Comparison of Residential Model Residuals



Staff's changes do not greatly affect the residential load forecast. The difference between Staff's and NWN's monthly residential load forecasts can be seen in Figure 2 below.

Figure 2. Residential Test Year Load Forecast Comparison



Q. Please describe Staff's proposed changes to the commercial load forecast.

A. Staff is proposing several changes to the commercial forecast. First, Staff notes that NWN uses two models to forecast commercial usage. One model forecasts usage for all commercial customers, while the other only forecasts usage for small commercial customers. For the model forecasting all commercial customers, Staff supports using a (1,0,0)(1,1,1)[12] ARIMA model as opposed to NWN's proposed (1,0,0)(0,0,1)[2] ARIMA model. Staff also recommends that all monthly fixed effects be removed from this model.

Instead, the seasonal differencing will account for the seasonal variation in usage.

Staff notes that this parameterization was not chosen by algorithm but was instead manually chosen by Staff. Staff chose to override the model as the algorithmically parameterized model forecasted summer months much higher than the historical norms. A comparison of the forecasts produced by each of these models can be seen in Figure 3. Staff also included a squared HDD term in its model and removed weather variables with negligible impact on the model. Overall, Staff's model has a comparable fit to the automatically parametrized model with monthly fixed effects. The comparison of residuals of each of these models can be seen in Figure 4.

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Staff/1900
Stevens/8

Figure 3. Comparisons of Commercial Forecasts

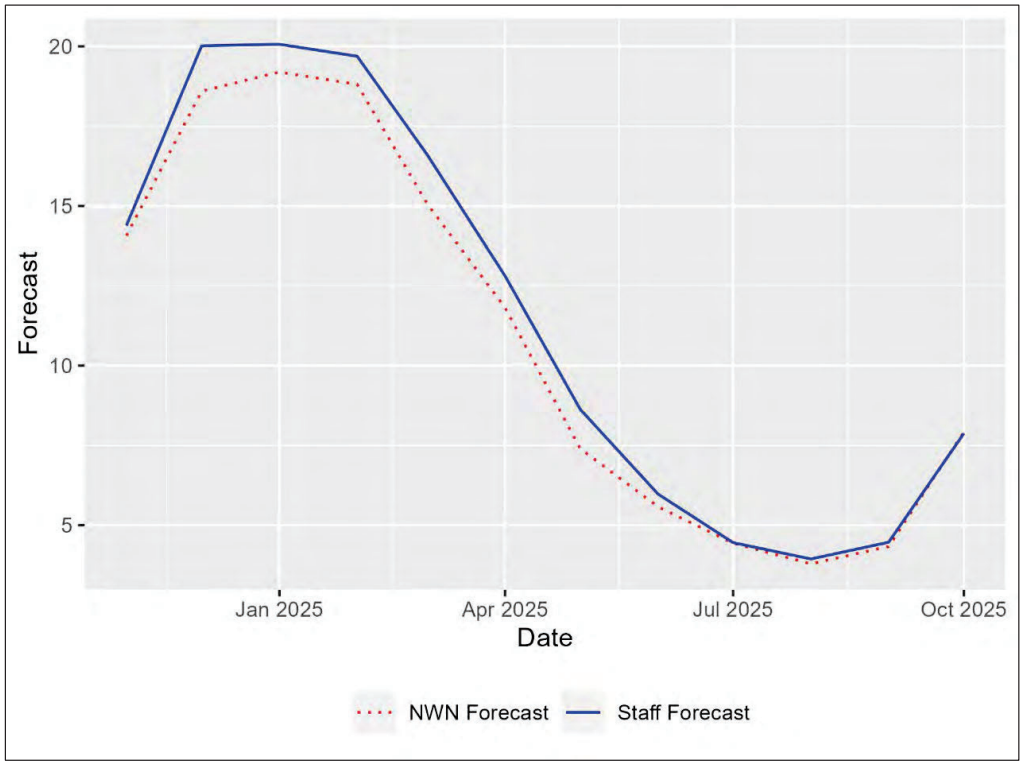
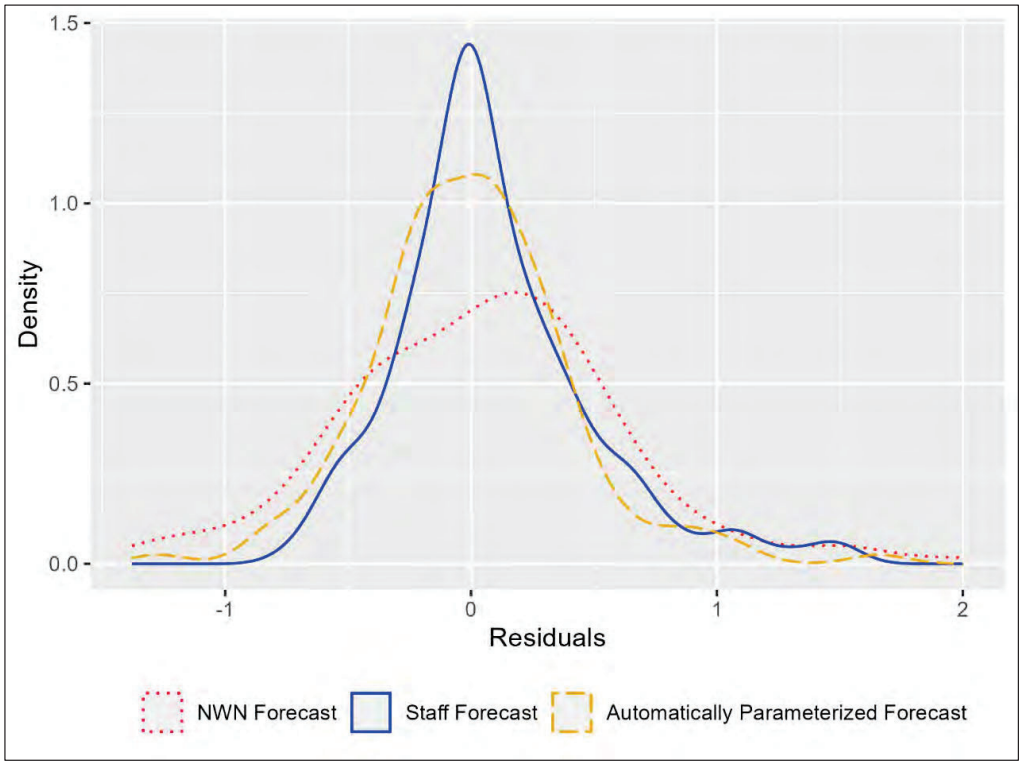


Figure 4. Comparison of Commercial Model Residuals



For the small commercial model, Staff similarly recommends removing monthly fixed effects from the model and instead relying on seasonal differencing. Staff recommends using a (0,1,1)(1,2,1)[12] ARIMA model as opposed to NWN's (1,0,0)(0,0,1)[2] ARIMA model. Again, the model produced via Staff's preferred parameterization algorithm produced unrealistic summer usage estimates. Staff also included a squared HDD term and removed weather variables with negligible impacts on the model. A comparison of the forecasts and model fit can be seen in Figure 5 and Figure 6 respectively.

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Figure 5. Comparisons of Small Commercial Forecasts

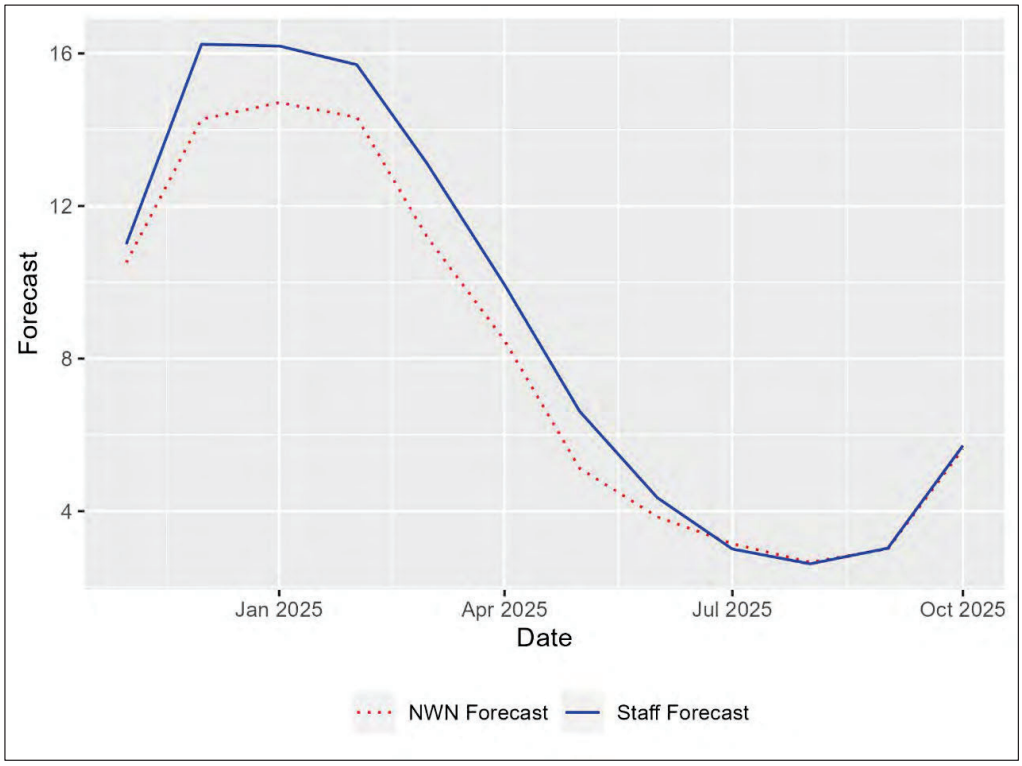
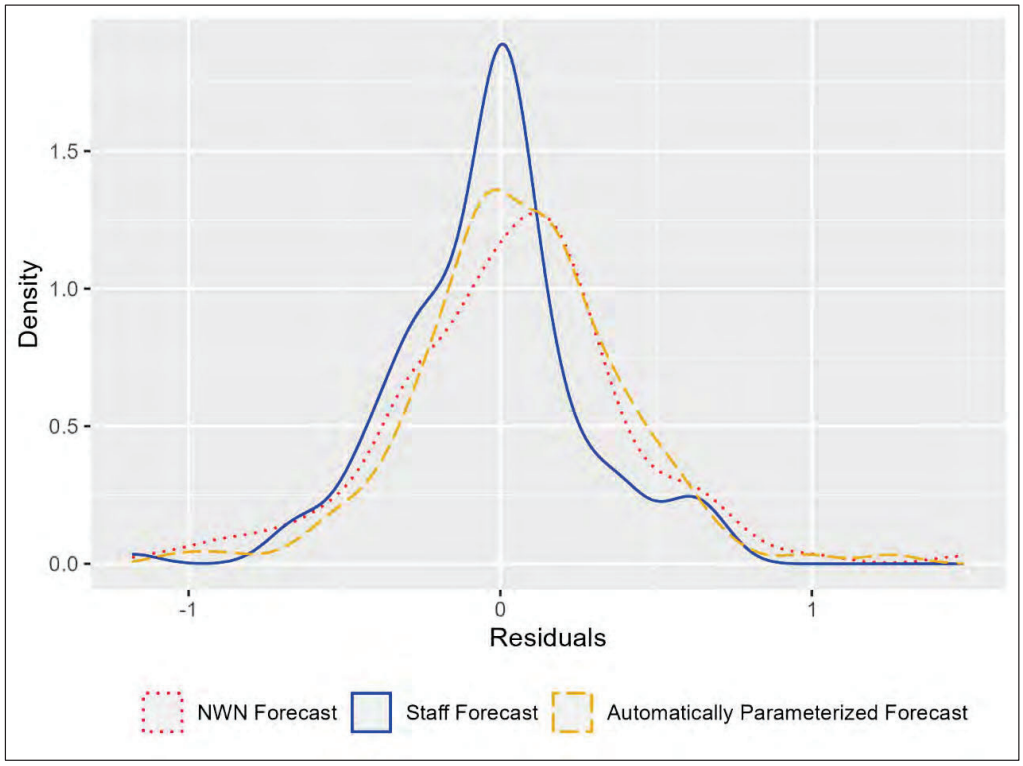


Figure 6. Comparison of Small Commercial Model Residuals



Q. How do Staff's proposed changes affect the commercial load forecast?

A. Staff's proposed modifications to the load forecast are to enhance the model's flexibility and improve its interpretability. Staff's changes do improve the fit of the model as measured by the AIC and BIC. Staff's forecast slightly increases the Test Year load forecast for commercial customers, primarily through a higher forecasted peak consumption in winter months.

Q. Please describe Staff's proposed changes to the Schedule 27 (Residential Dry-Out) forecast.

A. Staff is proposing several minor modifications to the Schedule 27 model. First, Staff proposes using a (1,0,0) ARIMA model as opposed to NWN's proposed

(1,0,1) ARIMA model. Staff's proposed parameterization was automatically selected using the Hyndman-Khandakar algorithm. Further, Staff recommends using monthly fixed effects and removing weather variables with a negligible effect on the model.

Q. How do Staff's proposed changes affect the Schedule 27 load forecast?

A. Staff's recommended modifications have a very small impact on the Schedule 27 load forecast. The difference between Staff's and the Company's forecasts can be seen below in Figure 7. These modifications to the load forecast are largely to help the model be more flexible and help improve interpretability. Staff's changes do improve the fit of the model as measured by the AIC and BIC. The comparison of Staff and the Company's proposed models can be seen in Figure 8 below.

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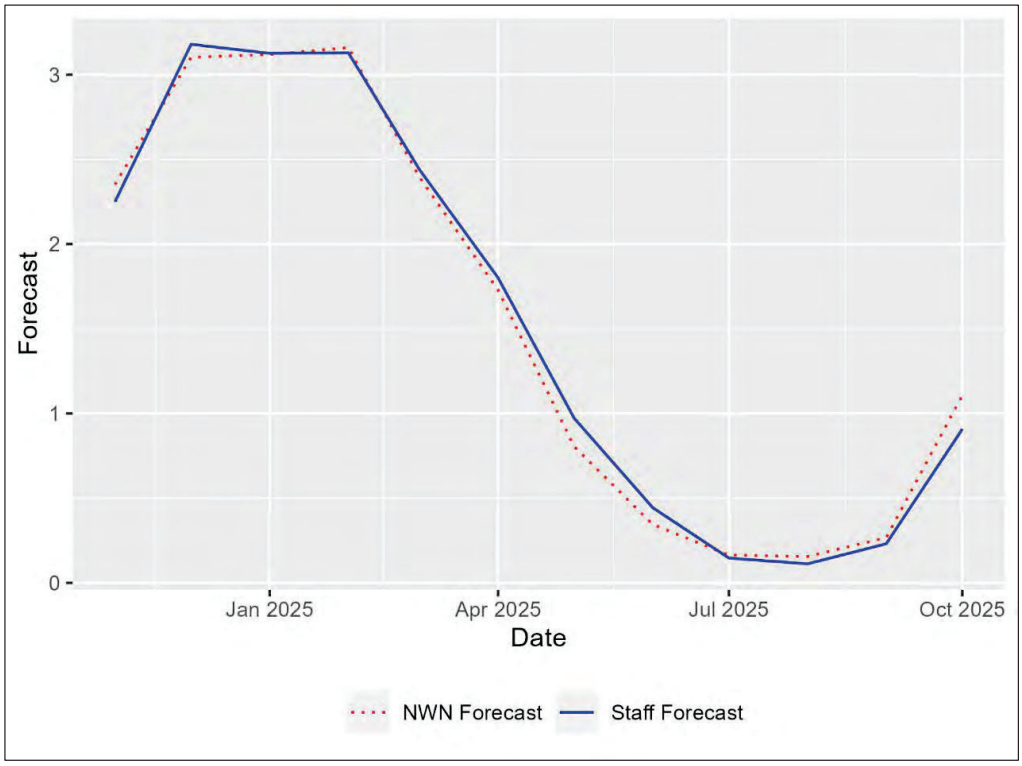
Figure 7. Comparison of Schedule 27 Forecasts



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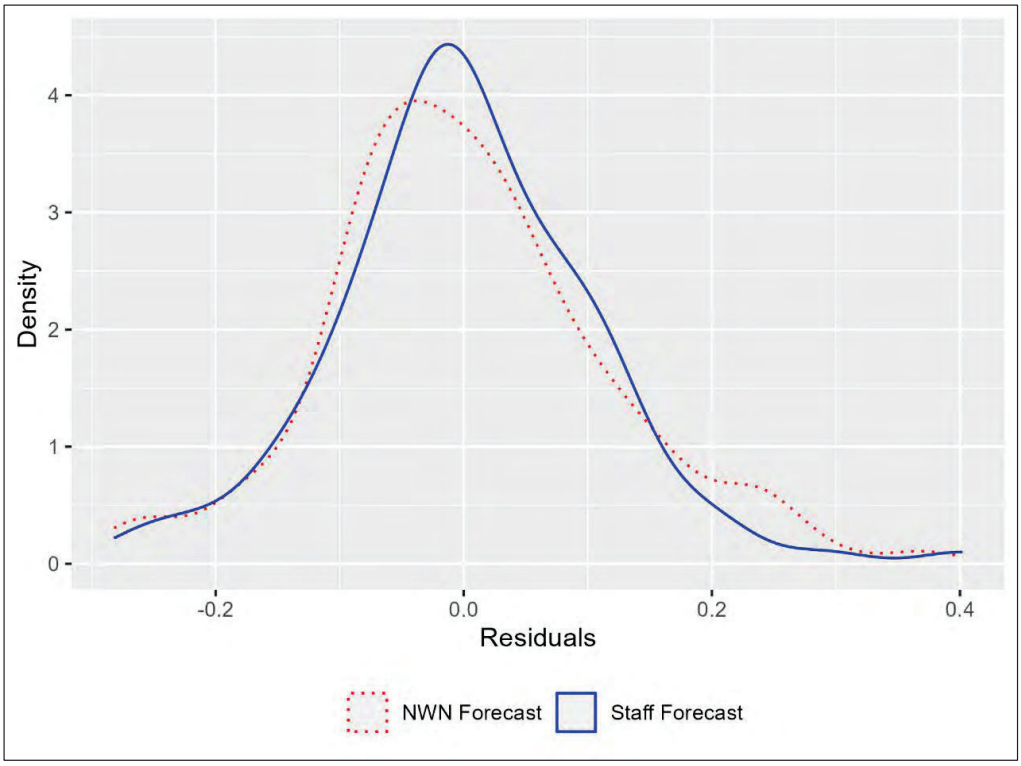
Staff/1900
Stevens/14

Figure 8. Comparison of Schedule 27 Model Residuals



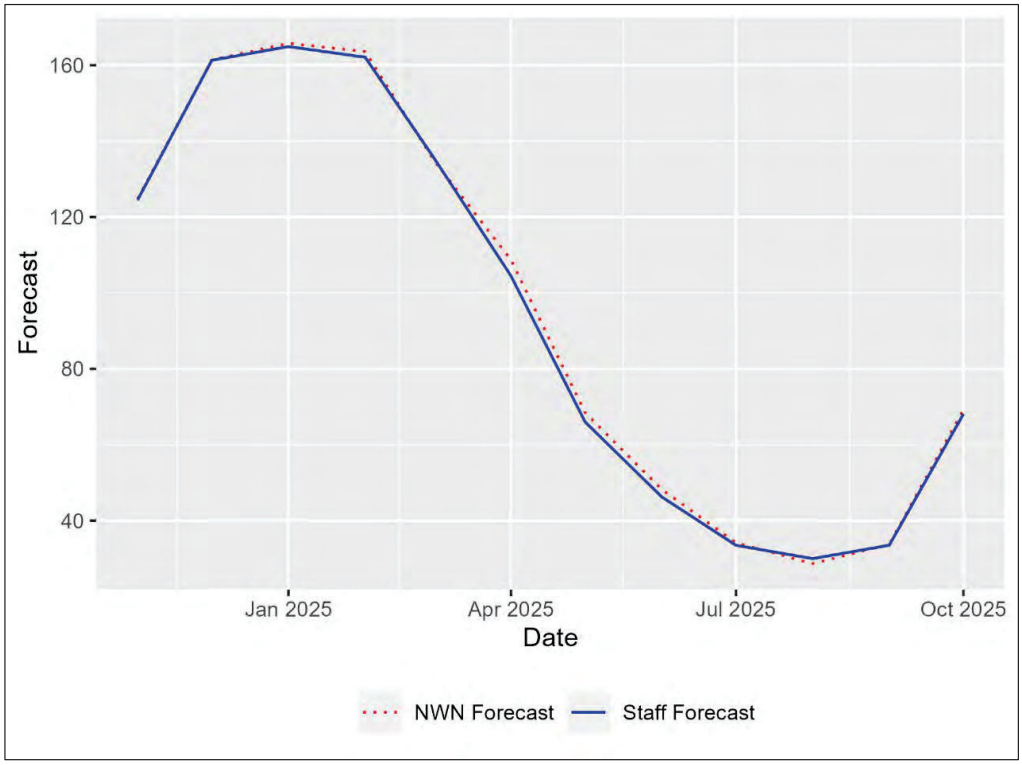
Q. Please describe Staff's proposed changes to the Schedule 31 (Non-Residential Firm Sales and Firm Transportation Service) forecast.

A. For NWN's Schedule 31 forecast, Staff is recommending the same changes be made as recommended for the Schedule 27 forecast. Namely, Staff recommends that a (1,0,0) ARIMA model be used as opposed to a (1,0,1) ARIMA model, monthly fixed effects be used, and weather variables with a negligible impact on the model be omitted.

Q. How do Staff's proposed changes affect the Schedule 31 load forecast?

A. Again, the effects of Staff's recommended changes have a relatively small impact on the overall forecast for Schedule 31 and are largely to help the model be more flexible and help improve interpretability. The Staff and Company forecasts can be seen below in Figure 9. Staff's changes do improve the fit of the model as measured by the AIC and BIC. The comparison of Staff and the Company proposed models can be seen in Figure 10 below.

Figure 9. Comparison of Schedule 31 Forecast



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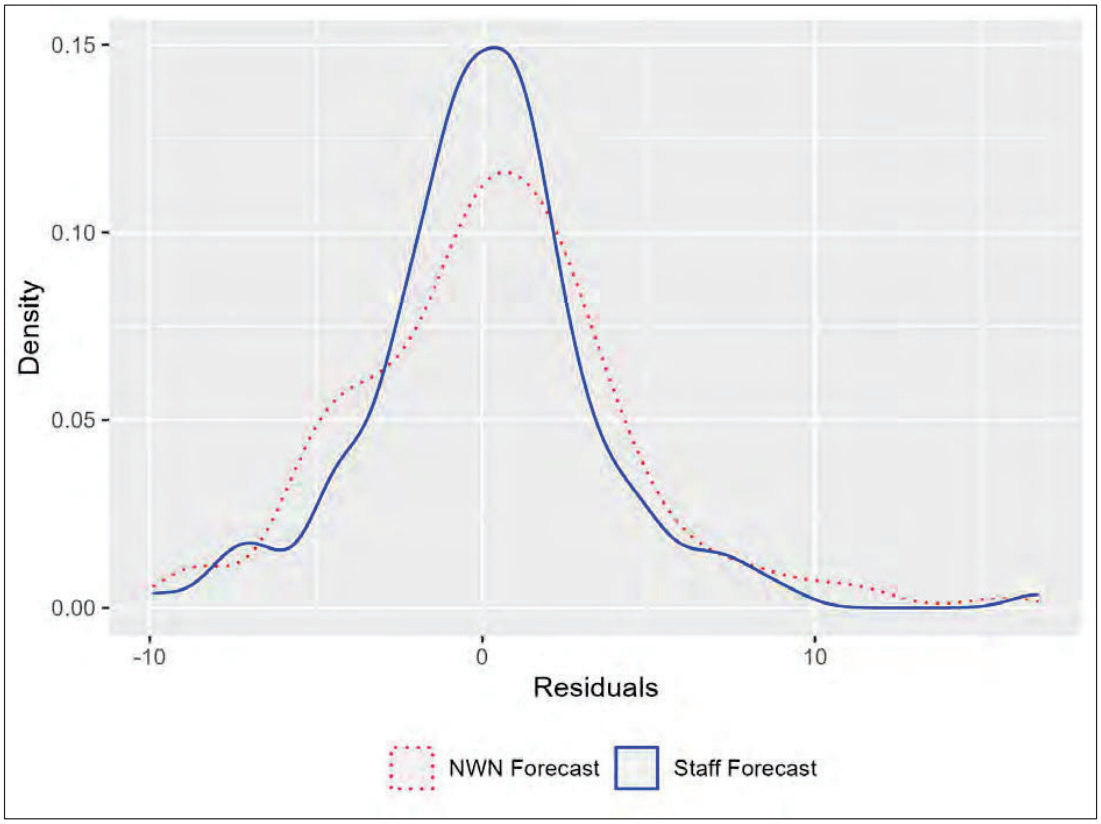
Staff/1900
Stevens/16

Figure 10. Comparison of Schedule 31 Residuals



Q. Please describe Staff's proposed changes to the Schedule 32 (Large Volume Non-Residential Sales and Transportation Service) forecast.

A. For NWN's Schedule 31 forecast, Staff is recommending more substantive changes. Staff recommends that a (1,0,0)(1,2,1)[12] ARIMA model be used as opposed to a (1,0,0) ARIMA model. As with the commercial models discussed above, Staff is recommending that no monthly fixed effects be included in the model and that seasonal differencing instead be used to control for seasonal variation. Staff is also recommending that weather variables that have a negligible effect on the forecast be removed.

Staff notes that this parameterization was not chosen algorithmically but was manually selected by Staff. Similar to the commercial models, the algorithmically parameterized model with monthly fixed effects produced a summer season forecast that was much higher than any historical consumption. Staff's parameterization is meant to produce a summer forecast that is more in line with historical consumption, while still improving fit and adequately controlling for seasonality.

Q. How do Staff's proposed changes affect the Schedule 32 load forecast?

A. Staff's recommended changes increase the Schedule 32 slightly. This increase is uniform in each month but is most pronounced in the peak period. The difference between Staff's recommended model, NWN's model, and the algorithmically parameterized models can be seen below in Figure 11.

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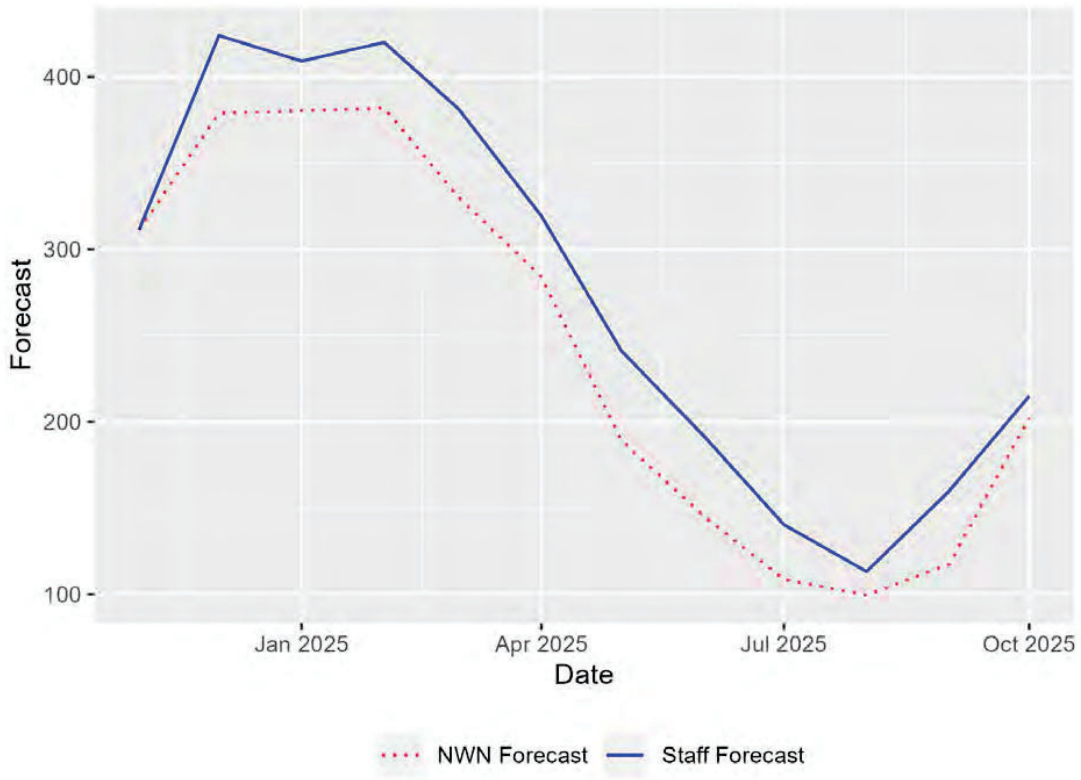
Staff/1900
Stevens/18

Figure 11. Comparison of Schedule 32 Forecast



Both Staff's model and the algorithmically parameterized model provide improvement to the fit as measured by the AIC and BIC. Each model's distribution of residuals can be seen below in Figure 12.

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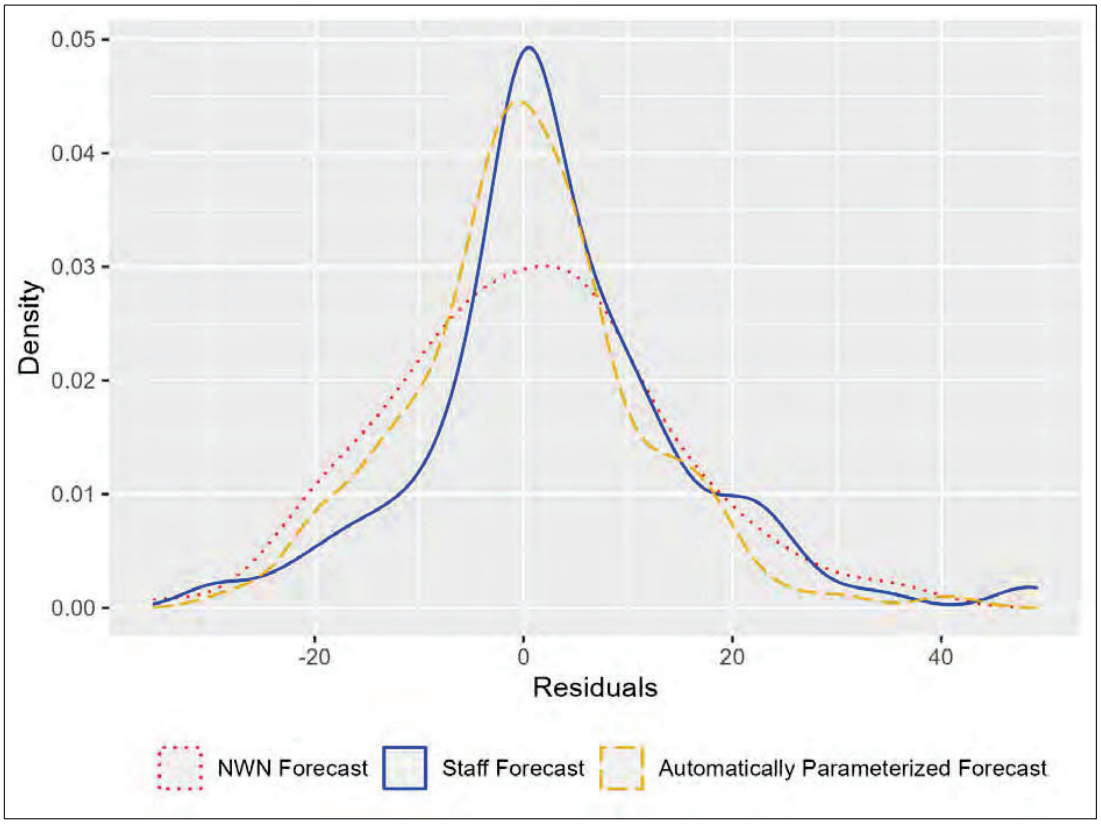
Staff/1900
Stevens/19

Figure 12. Comparison of Schedule 32 Residuals



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Staff/1900
Stevens/20

ISSUE 2. DECOUPLING

Q. Please summarize NWN's proposal regarding its decoupling mechanism.

A. NWN is proposing to bifurcate the residential Decoupling calculation between established customers and new customers that join the system after each rate case. This change would modify the decoupling revenue calculation by comparing new premise residential customer usage to a lower baseline level. NWN's proposal is based on Staff's recommendation in UG 435. This proposal is meant to account for the fact that customers joining the system will not have the same baseline consumption distribution as established customers on the system. If the system-wide baseline consumption, calculated in the most recent rate case, is applied to all customers joining the system between rate cases, the Company may over collect via its decoupling mechanism as new customers consume significantly less than the system-wide average.

NWN proposes using customer usage data from 2018-2022 to estimate the baseline consumption of new customers connecting between rate cases. NWN also proposes beginning the bifurcation of the Decoupling mechanism after the difference between normal and actual heating degree days is calculated.

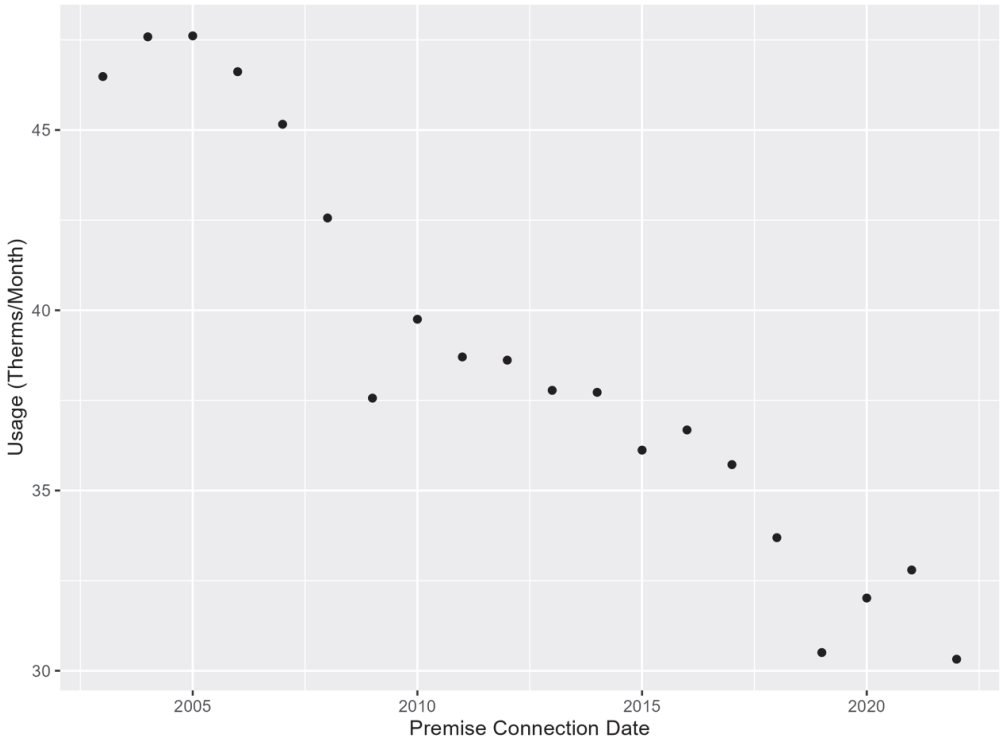
Q. How has usage changed for newer customers?

A. Figure 13 shows the average monthly usage for premises connected from 2003-2022.[4] This shows that the average yearly consumption of a premise

[4] Figure 13 was created using data obtained in Staff DR 390.

connecting to NWN's system has consumed nearly one less therm per month than a premise that was connected in the prior year. This decrease in average usage is stark and represents many technological and economic changes in NWN's service territory.

Figure 13. Average Monthly Usage by Premise Connection Year



Q. Does Staff agree that the bifurcation should only be applied to customers being added between rate cases?

A. No. After further review of the data, Staff is recommending that the residential class, for the purposes of the Decoupling mechanism, be fully bifurcated between "new" and "existing" customers on a permanent basis.

That is, “new” customers would not be folded into the “existing” customer category during rate cases and would remain separate going forward.

Q. What is Staff’s rationale for this recommendation?

A. Staff’s concern is largely around customer attrition. Staff’s initial decoupling recommendation in UG 435 was made to solve the issue presented by new customers being systematically different than existing customers. However, in this updated recommendation Staff is aiming to also address the fact that customers leaving the system are likely different than customers who have recently joined the system.

NWN’s decoupling mechanism accounts for differences both in usage per customer and customer count compared to the load forecast. If the baseline for “existing” customers includes all customers connected at the time of the rate case, then the system-wide baseline usage and heating coefficient will be the weighted averages of older and newer customers. However, customers who leave the system are likely not customers who have only connected to the system recently. As such, the usage distribution of customers leaving the system is likely shifted to right of the usage distribution for the entire system. This would then lead to a mechanism that compares customers remaining on the system to a baseline usage that is skewed upward. Permanently bifurcating the decoupling mechanism between “existing” and “new” customers would help mitigate the impact of this phenomenon.

Q. What year should be used to designate "new" customers for the decoupling mechanism going forward?

A. "New" customers, for the purpose of the decoupling bifurcation, should be considered as any customer who connected to the system beginning in 2018. Staff chose this year for several reasons. First, NWN implicitly acknowledges in its testimony that customers who joined the system after this date have significantly different consumption compared to existing customers as they used this group to calculate their indicative baseline for new customers. Second, all houses built on and after 2018 would be subject to the updated residential building codes set in 2017. Lastly, Figure 13 shows that average usage of customers that connected to the system between 2018-2022 has remained fairly constant. This indicates that the rate of change in UPC may be stabilizing, or at least slowing down. As such, this cohort of customers will likely be more similar to each other than customers who connected to the system before 2018.

Staff does recognize that the exact year of delineation is somewhat subjective. One could easily argue that 2017 or 2019 may be better or equally as good as 2018 for separating these groups and as such, no delineation should be made. However, Staff argues that it is still worthwhile to establish a partition between these groups even if no delineation will be perfect.

Q. Does Staff believe that the definition of this bifurcation group should remain unchanged in all future rate cases?

A. No. If customer usage patterns sufficiently change in future years, it may be prudent to redefine the delineation between older and new customers.

Q. Does Staff agree that the bifurcation should take place after the difference between the normal and actual heating degree days is calculated?

A. No. Staff recommends that the Company calculate separate heating coefficients separately for both customers who connected before and after 2018. Staff recognizes that this recommendation runs counter to Staff's proposal in UG 435.[5] However upon further review, Staff has altered its recommendation. This change is meant to reflect the fact that new customers to the system will likely both have lower baseline usage and reactions to weather fluctuations. This phenomenon is due to newly connected premises having newer and more efficient heating systems and homes that were built to modern residential building codes. If the weather normalized usage for these customers is not updated to reflect this, then the decoupling mechanism will be set assuming a higher level of usage for new customers than should be anticipated.

[5] Staff/1300, Scala/27.

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Staff/1900
Stevens/25

ISSUE 3. RATE BASE CALCULATION

Q. From a high level, please describe how Northwest Natural calculates rate base in this case.

A. NWN is proposing to use a 13-month Average-of-Monthly-Averages (AMA) approach to calculate rate base in this case. In this calculation, they do include growth-related capital additions in the Test Year, however, but do not include major capital additions.

Q. Does this methodology indicate a significant break from how rate base was calculated in the past?

A. No. Staff reviewed testimony from UG 435, and the high-level rate base calculation has remained the same.

Q. Does Staff agree with this calculation?

A. Yes. This is Staff's preferred methodology for calculating rate base. Staff is still in the process of reviewing the exact capital additions included in the calculation, but at this time has no issues with NWN's methodology. Staff may recommend that certain capital additions be excluded in future testimony if any inappropriate costs are found.

Docket No: UG 490

Staff/1900
Stevens/26

SUMMARY

Q. Please summarize your recommendations.

A. Staff is proposing relatively minor changes to NWN's load forecast. These changes are meant to improve transparency and flexibility of NWN's econometric load forecasting models. In general, these recommendations involve automatically parameterizing ARIMA models as a baseline, using non-linear weather variables, using seasonal ARIMA terms when applicable, and removing weather variables with small effects. Staff is proposing that NWN bifurcate its proposed decoupling mechanism before the difference between normal and actual heating degree days is calculated. This necessitates that a heating coefficient is separately calculated for new customers. Lastly, Staff does not have any recommendation regarding NWN's overall rate base calculation methodology at this time.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 490
WITNESS: BRET STEVENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1901

Witness Qualifications Statement

April 18, 2024

Docket No. UG 490

Staff/1901
Stevens/1

WITNESS QUALIFICATIONS STATEMENT

NAME: Bret Stevens

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist
Rates, Safety, and Utility Performance

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION: Ph.D., Agricultural & Resource Economics (2023)
University of California, Davis

M.S., Agricultural & Resource Economics (2017)
University of California, Davis

B.A., Economics/Environmental Studies (2016)
Western Washington University

EXPERIENCE: I have been employed at the Public Utility Commission of Oregon since September of 2022. My primary responsibilities revolve around providing research and analysis on rate spread and rate design. I have been a staff witness in UE 407, UE 410, UE 412, UE 414, UE 416, UE 421, UE 426 and UG 461. Prior to working for the Commission, I was employed by the University of California, Davis as a graduate student researcher, associate instructor, and teaching assistant. I taught courses on econometrics, finance, and microeconomics.

CASE: UG 490
WITNESS: Steph Yamada

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2000

REDACTED
OPENING TESTIMONY
Highly Confidential Information is Subject to Modified Protective Order No. 23-480

April 18, 2024

Docket No: UG 490

Staff/2000
Yamada/1

Q. Please state your name, occupation, and business address.

A. My name is Steph Yamada. I am a Senior Utility Analyst employed in the Rates and Telecommunications Section of the Rates, Safety and Utility Performance (RSUP) Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/2001.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide background, analysis, and recommendations regarding the Company's Test Year inclusions for wages, salary, incentives, and full-time equivalents (FTE).

Q. Did you prepare any exhibits for this docket?

A. Yes. In addition to my witness qualifications statement provided in Exhibit Staff/2001, I prepared the following supporting exhibits: Exhibit Staff/2002 (NW Natural's Non-Confidential DR Responses), Exhibit Staff/2003 (NW Natural's Highly Confidential DR Responses), and Exhibit Staff/2004 (Staff's Highly Confidential Workpapers).

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Salaries & Wages 3
Figure 1: Test Year Salaries, Wages, Overtime 3
Issue 2. Incentives 8
Figure 2: Company Proposed Incentives 8

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Q. Could there be changes or updates to Staff's position and recommendations?

A. Yes. My testimony represents issues identified to date. My recommendations and issues may change when informed by new data and after reviewing testimony and analysis by other parties.

Docket No: UG 490

Staff/2000
Yamada/3

ISSUE 1. SALARIES & WAGES

Q. Please summarize the Company's proposal for salaries and wages in this case.

A. The Company proposes to include salaries, wages, and overtime totaling **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** in Oregon in the Test Year,[1] as summarized in Figure 1.

FIGURE 1: TEST YEAR SALARIES, WAGES, OVERTIME

[BEGIN HIGHLY CONFIDENTIAL]

Category	Base Salaries & Wages	Overtime
Officers	$4,982,411	$0
Exempt	$65,175,815	$0
Nonexempt	$748,875	$5,242
Union	[redacted]	[redacted]
Total	[redacted]	[redacted]

[END HIGHLY CONFIDENTIAL]

For non-union employees and officers, the base wage amounts shown in Figure 1 were determined by escalating calendar year 2023 costs by 5.30 percent in 2024 and 4.85 percent in 2025.[2] The base wages for union employees were calculated **[BEGIN HIGHLY CONFIDENTIAL]** [redacted][3]

[1] Staff/2003, NW Natural's Response to Staff's SDR 92, HIGHLY CONFIDENTIAL Attachment 1 (Viewable only in Huddle).
[2] NW Natural/1000, Rogers/6.
[3] NW Natural/1000, Rogers/7, lines 11-13 and 17-20, HIGHLY CONFIDENTIAL.

[redacted] **[END HIGHLY CONFIDENTIAL]**[4]

Q. How does the Company determine employee compensation?

A. For non-union employees, NW Natural uses survey data to align its base pay with the median of the market for comparable jobs with other companies.[5] Union employees' total compensation is determined through a negotiated process that incorporates selected market survey data and union contracts.[6] For officers, the Company uses competitive compensation data, which are collected and analyzed by an independent compensation consultant, Pay Governance, to determine appropriate compensation levels.[7]

Q. Please provide a summary of the Commission's historical method for determining the amount to include in a utility's revenue requirement for salaries and wages, including overtime.

A. The Commission generally determines the appropriate level of wages and salaries for employees in the Test Year using Staff's three-year Wage and Salary (W&S) model to estimate union and non-union payroll levels for energy utilities.[8,9] The model calculates an appropriate level of Test Year expense

4 NW Natural/1000, Rogers/5, lines 7-9, HIGHLY CONFIDENTIAL.
5 NW Natural/1000, Rogers/4, lines 3-6.
6 NW Natural/1000, Rogers/4, lines 14-22.
7 NW Natural/1000, Rogers/5, lines 16-23.
8 *In the Matter of Northwest Natural*, Docket No. UG 132, Order No. 99-697 at 43 (November 12, 1999), *In the Matter of PacifiCorp*, Docket No. UE 374, Order No. 20-473 at 102 (December 18, 2020).
9 *See Pacific Power & Light*, UE 116, Order No. 01-787 at 40; *In the Matter of Northwest Natura*l, Docket No. UG 132, Order No. 99-697 at 43 (November 12, 1999); *In the Matter of PGE*, Docket No. UE 102, Order No. 99-033 at 61 (January 27, 1999); *In the Matter of PGE*, Docket No. UE 88, Order No. 95-322 at 10 (March 29, 1995).

and capital investment for wages and salaries by escalating the Company's base year wages and salaries by annual changes to the All Urban CPI (for non-union labor) or negotiated increases (for union labor). For the purposes of this analysis, the base year is three years prior to the Test Year. The model then applies a sharing mechanism between the wages and salaries determined by the W&S model and the wages and salaries proposed by the utility. The Commission has previously declined to apply the sharing mechanism to union wages, instead basing the Test Year inclusion on the contracted increases in applicable union agreements.[10]

Q. Why has the Commission used the W&S model to determine the Test Year inclusion for non-union wages and salaries?

A. The Commission has explained its rationale in previous orders. For example, in an order issued in 1999, the Commission explained:

> The [Three Year] model incorporates actual market-based data by using, as a starting point, actual historic wages. We also agree with Staff's use of the All-Urban CPI index to adjust historic wages and salaries. Adjusting payroll levels by changes in inflation provides the employees the same real level of compensation as in the base year and provides an incentive to companies to minimize labor costs. Contrary to the assertions by NW Natural, local economic conditions are represented in the All-Urban CPI, as the Bureau of Labor Statistics includes prices in Oregon when it conducts its survey. Moreover, Staff's method of sharing the difference between payroll projections equally between ratepayers and shareholders also allows NW Natural some ability to increase wages above the rate of inflation in response to changes in market conditions without allowing unchecked escalation.[11]

[10] *In the Matter of PacifiCorp*, Docket No. UE 374, Order No. 20-473 at 100 (December 18, 2020).
[11] *In the Matter of Northwest Natural*, Docket No. UG 132, Order No. 99-697 at 43 (November 12, 1999).

Q. Please explain how Staff used the Three-Year W&S model to arrive at its recommendation for base wage and salary levels for the Test Year.

A. Consistent with the W&S model, Staff began with actual wage information from three years prior to the Test Year.[12] With a Test Year of November 1, 2024, to October 31, 2025, Staff began with 2022 wage information and escalated it to 2025 using All-Urban CPI rates, which are 4.1 percent for 2023, 2.7 percent for 2024, and 2.0 percent for 2025.[13] Staff then applied the sharing principle to Staff's and the Company's projected 2024 Test Year amounts for non-union labor. The sharing principle, which allows the Company to share 50/50 the lesser of the difference between the Company's and Staff's calculated projections, or a 10 percent band around Staff's calculated projection, results in a ($672,170) adjustment to Staff's projection for officer wages and a ($801,812) adjustment to exempt employee wages at the Oregon level.[14] Finally, these adjustments are allocated 64.9 percent to O&M and 35.1 percent to capital.[15] Staff did not make any adjustments to union labor.

Q. What is Staff's recommended adjustment for base salaries and wages?

A. Staff recommends a total adjustment of ($1,473,983) attributable to the Company's base salaries and wages for Oregon, excluding union labor. This amount is allocated ($956,615) to O&M and ($517,368) to capital.

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12 Staff/2003, NW Natural's Response to Staff's SDR 92, HIGHLY CONFIDENTIAL Attachment 1 (Viewable only in Huddle).
13 Oregon Economic & Revenue Forecast - March 2024 - Volume XLIV, No. 1, Table A.4, page 43.
14 See Staff/2004, Staff's HIGHLY CONFIDENTIAL Workpapers, "PUC 3-year W&S" Tab.
15 Staff/2002, NW Natural's Response to Staff's SDR 93.

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Staff/2000
Yamada/7

Q. Does Staff recommend further adjustments to union employee wages?

A. Yes. Staff recommends that union wages be updated to reflect actual negotiated union wage increases for the Test Year once those amounts are known. Staff's recommended totals reflect the Company's current estimate for union compensation, which was developed as discussed previously. The current contract for union employees is set to expire on May 31, 2024, and NW Natural is currently in negotiations with the bargaining unit for a new contract.[16] The Company **[BEGIN HIGHLY CONFIDENTIAL]** [redacted][17] [redacted] **[END HIGHLY CONFIDENTIAL]**.[18]

Q. Please explain how Staff used the Three-Year W&S model to arrive at Staff's overtime recommendation for the Test Year.

A. Staff's overtime analysis follows the same methodology as that used for base salaries and wages, which was discussed previously. The results of this analysis are shown in Staff's workpapers.[19]

Q. What is Staff's recommended adjustment for overtime?

A. Staff recommends an adjustment of ($4,935) attributable to the Company's non-exempt employee overtime for Oregon. This amount is allocated ($3,203) to O&M and ($1,732) to capital.

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16 NW Natural/1000, Rogers/5, lines 1-3.
17 NW Natural/1000, Rogers/5, lines 4-5.
18 NW Natural/1000, Rogers/5, lines 11-12.
19 See Staff/2004, Staff's HIGHLY CONFIDENTIAL Workpapers, "PUC 3-year OT" Tab.

Docket No: UG 490

Staff/2000
Yamada/8

ISSUE 2. INCENTIVES

Q. Please summarize the Company's proposal for incentives in this case.

A. The Company is seeking recovery of incentives totaling $9,340,431 in Oregon.[20] This amount is allocated from a system total of $10,528,091.[21] The breakdown of the Oregon amount is summarized in Figure 2, as follows.[22]

FIGURE 2: COMPANY PROPOSED INCENTIVES

Incentive	Exempt	Non-Exempt	Total
Annual Incentive (Short-Term)	$8,065,357	$52,562	$8,117,919
Long Term Incentive Pay (O&M)	$130,315	$0	$130,315
Stock Expense (RSU) (O&M)	$895,024	$0	$895,024
Employee Stock Purchase Plan	$197,173	$0	$197,173
Total	**$9,287,869**	**$52,562**	**$9,340,431**

The Company has excluded all executive incentive compensation from the Test Year.[23,24] Union employees are not eligible for pay-at-risk.[25] The Employee Stock Purchase Plan (ESPP) is not identified by employee type,[26] and is included in the Exempt column in Figure 2.

Q. Does NW Natural argue that incentives should be fully includable in rates?

A. Yes. NW Natural proposes to include the full amount of non-officer incentives as shown in Figure 2. The Company argues that pay-at-risk "represents an

[20] NW Natural/1000, Rogers/13, line 6.
[21] Staff/2002, NW Natural's Response to Staff's DR 142, Attachment 1.
[22] Staff/2002, NW Natural's Response to Staff's DR 142, Attachment 1.
[23] NW Natural/1400, Davilla/14.
[24] Staff/2002, NW Natural's Response to Staff's DR 142, Attachment 1.
[25] NW Natural/1000, Rogers/10.
[26] Staff/2002, NW Natural's Response to Staff's DR 142, Attachment 1.

essential part of competitive total compensation," and "is necessary for NW Natural to compete in the job market."[27] Regarding Restricted Stock Units (RSUs), the Company asserts that RSUs, which vest over four years, are "eligible for full cost recovery,"[28] stating that such incentives "are not awarded to incentivize financial performance."[29] While the Company has excluded officer incentives from its request "[g]iven the sizeable increase to revenues requested in this rate case,"[30] it maintains that such costs are prudently incurred, and that its "position [has not] changed regarding the ability to recover the costs of pay-at-risk pay for officers of the Company."[31] The Company further argues that the "Commission should treat the question of cost recovery for pay-at-risk on a case-by-case basis."[32]

Q. Please provide a summary of the Commission's historical method for determining the amount to include in a utility's revenue requirement for incentives.

A. To determine the appropriate amount to include in revenue requirement for incentives paid to employees, the Commission's policy is to disallow 100 percent of officers' bonuses because they are typically based on increased earnings, which benefits shareholders.[33] It is also Commission policy to disallow 75 percent of performance-based bonuses because they are generally

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27 NW Natural/1000, Rogers/8, lines 6-7.
28 NW Natural/1000, Rogers/12, lines 18-21.
29 NW Natural/1000, Rogers/12, lines 21-22.
30 NW Natural/1000, Rogers/9, line 5.
31 NW Natural/1000, Rogers/9, lines 8-17.
32 NW Natural/1000, Rogers/13, lines 10-11.
33 See Order No. 99-033 at 62; and *In the Matter of the Application of US West*, Docket No. UT 125, Order No. 97-171 at 74-76 (May 19, 1997).

focused on increased earnings and therefore bring more benefit to shareholders.[34] The Commission disallows 50 percent of merit-based bonuses because they equally benefit shareholders and ratepayers.[35] Union bonuses are treated in the same manner as non-union bonuses.[36] In this case, the issue of union bonuses is not relevant because union employees are not eligible for such compensation.

Q. Please describe Staff's analysis with regard to incentives.

A. As discussed previously, the Company proposes to include incentives totaling $9,340,431 in the Test Year. Since the Annual Incentives are calculated as a percentage of payroll and Staff made downward payroll adjustments as described previously, Staff first made a corresponding adjustment to the Company's proposal for Annual Incentives. Since the Company's proposed Annual Incentive inclusion is limited to exempt and nonexempt employees, Staff based its corresponding adjustment on Staff's base salary & wage adjustment in those employee categories. Staff allocated the reduction to exempt and nonexempt employees in the same proportions reflected in the Company's Test Year proposal. This adjustment is summarized in Figure 3 as follows.

[34] See Order No. 20-473 at 104.
[35] See Order No. 20-473 at 104.
[36] See Order No. 20-473 at 97; Order No. 99-697 at 44-45; Order No. 99-033 at 62.

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Staff/2000
Yamada/11

FIGURE 3: STAFF'S ANNUAL INCENTIVES ADJUSTMENT – OREGON

Staff's Initial Short-Term Incentives Adjustment	
Company Proposed Annual Incentive	$8,117,919
Staff's Exempt & Nonexempt Salary Adjustment	-5.30%
Staff's Corresponding Annual Incentive Adjustment	$(430,136)
Staff Adjusted Annual Incentive	**$7,687,783**

Next, Staff adjusted the Company's Long-Term Incentive Pay, Stock Expense, and ESPP in accordance with Staff's proposed FTE adjustment. Staff's proposal for exempt and nonexempt FTEs (discussed elsewhere in this testimony) represents a 4.14 percent reduction from the Company's proposed level. Consequently, Staff reduced Long Term Incentive Pay, Stock Expense, and the ESPP by 4.14 percent, or a total of ($50,597) in those categories.

Staff categorized the incentives as merit-based. Consequently, Staff reduced its adjusted incentives figures by 50 percent, in line with standard Commission practice. Staff's adjustment was allocated between O&M and capital in the same manner as described previously for salaries and wages. As described previously, the Company has already excluded 100 percent of officer incentives, in line with standard Commission practice.

Q. Has NW Natural demonstrated that the Commission should deviate from its longstanding practices regarding incentives and include the full amount of the Company's proposal?

A. No, NW Natural has not made a persuasive demonstration for why the Commission should deviate from its longstanding practices. The Company has primarily argued that pay-at-risk "represents an essential part of competitive

total compensation," and "is necessary for NW Natural to compete in the job market[.]"[37] The Company has made similar arguments in previous cases. For example, in Docket No. UG 132, the Company initially proposed "that 100 percent of the non-officers' bonuses be included in utility expense," and argued that "the bonuses are designed to make the company's total compensation package for these employees competitive with comparable jobs in the regional labor market."[38] In that case, the Commission concluded that Staff's recommendation to exclude 75 percent of performance-based bonuses and 50 percent of merit-based bonuses was "consistent with past ratemaking treatment of bonuses in prior electric and natural gas cases," stating that "NW Natural has not persuaded us that a change in policy is warranted."[39]

Q. The Company specifically argues that RSUs are eligible for full cost recovery. Why did Staff include RSUs in the amount that was reduced by 50 percent in its adjustment?

A. As discussed previously, the Commission typically excludes 50 percent of non-officer, non-performance-based incentives. Staff applied this reduction to its adjusted figure for RSUs, in accordance with Standard Commission practice.

Q. What is Staff's recommended adjustment for incentives?

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37 NW Natural/1000, Rogers/8, lines 6-7.
38 See Order No. 99-697 at 44.
39 See Order No. 99-697 at 45.

A. Staff recommends a total Oregon-allocated adjustment of ($4,910,582) attributable to the Company's employee incentives.[40] This amount is allocated ($3,186,968) to O&M and ($1,723,614) to capital.

[40] See Staff/2004, Staff's HIGHLY CONFIDENTIAL Workpapers, "PUC 3-year Incentives" Tab.

Docket No: UG 490

Staff/2000
Yamada/14

ISSUE 3. FTE

Q. Please summarize the Company's proposal for FTE in this case.

A. NW Natural proposes to include 1,183 employees in the Test Year at the system level.[41,42] This includes 1,170 FTEs existing at the end of the 2023 base year plus 13 additional employees that NW Natural expects to hire in the first half of 2024.[43] The Company removed 64.3 vacant FTEs and 63.7 non-regulated FTEs to arrive at the 1,183 total.[44] The system-wide and Oregon allocations are summarized in Figure 4 as follows.

FIGURE 4: COMPANY PROPOSED FTE

Type	System FTEs	Oregon FTEs
Officers	12.4	10.9
Exempt	560.4	497.1
Nonexempt	10.5	9.3
Union	599.6	531.9
Total	**1,183.0**	**1,049.2**

Q. Why does NW Natural propose to add 13 additional employees in 2024?

A. Eight of the proposed new FTEs relate to Information Technology & Services (IT&S) functions. These include four new Customer Information System (CIS) positions related to H2: Vista, three new operational technology positions, and

41 NW Natural/1000, Rogers/22.
42 Staff/2002, NW Natural's response to Staff's SDR 92, Attachment 1 (Non-Confidential portion).
43 NW Natural/1000, Rogers/21.
44 NW Natural/1400, Davilla/5.

one new security position.[45] The other five proposed new FTEs relate to decarbonization and compliance with the Climate Protection Program (CPP).[46]

Q. How has the Commission previously determined the appropriate FTE level for inclusion in rates?

A. Specific methodologies may vary somewhat on a case-by-case basis. However, the Commission has previously adopted Staff's principle that A&G non-union workforce should be limited to levels forecasted as a function of customers per FTE.[47]

Q. Please describe Staff's analysis with regard to FTEs.

A. For exempt and nonexempt employees, Staff first analyzed FTEs as a function of customers served per FTE. Staff's analysis indicated that between 2021 and 2023, the Company served an average of 1,469.9 customers per FTE at the Oregon level.[48,49] The Test Year proposal reflects 1,396.2 customers served per FTE in Oregon, representing a decrease of 73.7 customers per FTE, or five percent. Based on the total projected Oregon customer count of 707,022 at the end of the Test Year,[50] the three-year historical average of customers served per FTE would require a total of 481 exempt and nonexempt FTEs attributable to Oregon. The Company proposes to include 506.4, which is 25.4 higher than Staff's calculation. Staff proposes to remove these 25.4

45 NW Natural/700, Downing/51.
46 NW Natural/1500, Kravitz-Chittum/20.
47 See Order No. 99-033 at 63.
48 Staff/2002, NW Natural's Response to Staff's SDR 92 (Non-Confidential portion).
49 Staff/2002, NW Natural's Response to Staff's DR 153, Attachment 1.
50 Staff/2002, NW Natural's Response to Staff's DR 153, Attachment 1.

higher-than-average FTEs. This adjustment is applied to the exempt and nonexempt employee categories in the same proportions as reflected in the Company's Test Year proposal.

Staff also proposes to add back certain FTEs related to the new positions proposed by the Company. As discussed previously, the Company proposes to add 13 new employees in the Test Year—five related to the CPP, and eight related to IT&S functions. Staff proposes to exclude four of the eight proposed new IT&S FTEs and four of the five proposed new CPP FTEs. The resulting net increase of five FTEs is allocated 88.7 percent to Oregon,[51] and added to the exempt employee category. Together with Staff's 25.4 FTE reduction that was discussed previously, Staff's proposal represents a net reduction of 20.96 at the Oregon level compared to the Company's Test Year proposal. Staff's proposed FTE totals are summarized in Figure 5, following.

FIGURE 5: STAFF PROPOSED FTE

Type	Company (System)	OR Alloc.	Company (OR)	Staff Adjustment	Staff (OR)
Officers	12.42	88.1%	10.94		10.94
Exempt	560.39	88.7%	497.06	(20.49)	476.57
Nonexempt	10.52	88.7%	9.33	(0.47)	8.86
Union	599.63	88.7%	531.88		531.88
Total	**1,182.96**		**1,049.22**	**(20.96)**	**1,028.26**

Q. Did Staff make any adjustments to officer or union FTEs?

[51] Staff/2002, NW Natural's Response to Staff's SDR 92 (Non-Confidential portion).

A. No. While the Company's system-level officer FTE count has increased from 11.4 in 2020 to 12.4 in the Test Year,[52] this does not appear to be a departure from historical levels.[53] Union FTEs have increased by only 1.2 percent since 2020.[54]

Q. Please explain why Staff recommends the exclusion of four FTEs related to the CPP.

A. As explained in the testimony of Staff witness Curtis Dlouhy (Exhibit Staff/900), Staff believes that there is not enough work to warrant full time positions for at least two of the requested five new FTEs nor would it be proper to allow cost recovery for four of the five requested FTEs now that the CPP rules have been invalidated by the Oregon Court of Appeals Two of the roles were meant to perform duties directly related to CPP compliance prior to its invalidation, and the Company has not adequately convinced Staff that there is enough work for these roles to do absent the CPP.

Further, NW Natural and other litigants asked the Court to invalidate the CPP rules on both procedural and substantive grounds and the Court's opinion invalidating the rules only addressed the procedural concerns.[55] Staff anticipates that if the DEQ implements new CPP rules, the rules will be challenged once again. Staff believes that it is not in customers' best interest to

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52 Staff/2002, NW Natural's Response to Staff's SDR 92 (Non-Confidential portion).
53 Staff/2002, NW Natural's Response to Staff's DR 148.
54 Staff/2002, NW Natural's Response to Staff's SDR 92 (Non-Confidential portion).
55 *Northwest Natural Gas Company, et al. v. Environmental Quality Commission,* 329 Or. App. 648, 652 (2023) ("Petitioners raise numerous assignments of error, contending the CPP Rules are invalid. In this opinion, we address only one of those assignments because it is dispositive regarding the validity of the CPP Rules.").

allow the cost recovery of four out of the five positions to implement the CPP while the future of the CPP is still in doubt. Staff supports the inclusion of costs associated with the Peak Load Management Analyst because Staff believes that this position can provide value to customers even without the CPP.

Q. Please explain why Staff recommends the exclusion of four FTEs related to IT&S.

A. As explained in the testimony of Staff witness Julie Dyck (Exhibit Staff/1000), Staff expects that current CIS employees and the other remaining four new IT&S positions will be cross trained as this is replacing a legacy system. Those employees that were working on CIS-related projects before are better equipped to learn a new system. In addition, their IT&S FTE count in 2023, when completing the larger Horizon 1 program was 104, whereas their UG 490 request is 116. So even if all 8 positions are approved, their total IT&S FTE are likely to be around 112, which is four less than their request, since they are unlikely to fill all positions. Lastly, the costs of these FTEs are expected to be included in a Company requested deferral of costs to implement H2 along with the costs of the program itself. The Company plans to update their plans for deferral in their Reply Testimony.

Q. What is Staff's recommended adjustment for FTEs?

A. Staff's adjustment for FTEs at the Oregon level is summarized in Figure 6 as follows.

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Staff/2000
Yamada/19

FIGURE 6: STAFF'S EXEMPT & NONEXEMPT FTE ADJUSTMENT - OREGON

Description	Exempt	Nonexempt	Total
Test Period Base Wages & Salaries	$65,175,815	$748,875	$65,924,691
Staff Adjustment to Test Period Payroll	($801,812)	$0	($801,812)
Adjusted Payroll	$64,374,003	$748,875	$65,122,878
Ave. # of Employees (Test Year FTE)	497.06	9.33	506.40
Adjusted Average Salary	129,508	80,255	$209,763
Staff Proposed FTE	476.57	8.86	485.44
Staff Proposed Proforma Payroll	$61,720,286	$711,323	$62,431,609
Net Payroll Adjustment	**($2,653,716)**	**($37,553)**	**$2,691,269**

This adjustment is allocated between capital and O&M in the same manner as salaries & wages, as discussed previously. Staff's resulting recommended adjustment totals ($2,691,269) for Oregon, which is allocated ($1,746,634) to O&M and ($944,636) to capital.[56]

[56] See Staff/2004, Staff's HIGHLY CONFIDENTIAL Workpapers, "PUC FTE" Tab.

Docket No: UG 490

Staff/2000
Yamada/20

ISSUE 4. OTHER RELATED ADJUSTMENTS

Q. Do Staff's recommended adjustments to base salaries and wages, overtime, incentives, and FTEs, as discussed previously in this testimony, result in other related adjustments to the Test Year?

A. Yes. Staff's adjustments in these areas also result in associated reductions to depreciation expense and payroll tax.

Q. Please explain Staff's adjustment to depreciation expense.

A. Staff's recommended adjustments to base salaries and wages, overtime, incentives, and FTEs result in a total capital adjustment of ($3,187,350) related to Oregon. The removal of this amount from rate base requires a corresponding reduction to depreciation expense. The Company's filing reflects depreciation expense representing 4.15 percent of gross plant;[57] Staff applied that percentage to its proposed capital reduction, resulting in a $(132,130) adjustment to O&M.[58]

Q. Please explain Staff's adjustment to payroll tax.

A. Staff's payroll adjustments reflect a 3.24 percent reduction compared to the Company's proposed amounts. Staff made a corresponding adjustment to the Company's proposed inclusion for payroll taxes.[59] The resulting adjustment attributable to Oregon is ($367,505).[60]

Q. Please summarize the adjustments described in your testimony.

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57 NW Natural/1713, Walker/1, lines 1 and 22.
58 See Staff/2004, Staff's HIGHLY CONFIDENTIAL Workpapers, "PUC Depreciation" Tab.
59 Staff/2002, NW Natural's Response to Staff's DR 155, Attachment 1.
60 See Staff/2004, Staff's HIGHLY CONFIDENTIAL Workpapers, "PUC Payroll Taxes" Tab.

A. The Oregon-allocated adjustments reflected in my testimony are summarized in Figure 7, as follows.

FIGURE 7: SUMMARY OF STAFF'S ADJUSTMENTS – OREGON

Description	O&M	Capital
Wages & Salaries	($956,615)	($517,368)
FTE Adjustment	($1,746,634)	($944,636)
Incentives	($3,186,968)	($1,723,614)
Overtime	($3,203)	($1,732)
Payroll Taxes	($403,183)	$0
Depreciation Expense	($132,130)	$0
Total	**($6,428,731)**	**($3,187,350)**

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 490
WITNESS: STEPH YAMADA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2001

Witness Qualifications Statement

April 18, 2024

Staff/2001
Yamada/1

WITNESS QUALIFICATIONS STATEMENT

NAME: Steph Yamada

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Utility Analyst
Rates and Telecommunications Section
Rates, Safety and Utility Performance Program

ADDRESS: 201 High St SE, Suite 100, Salem, OR, 97301

EDUCATION: Master of Business Administration
Western Governors University

Bachelor of Science in Accounting
University of Oregon

EXPERIENCE: I have been employed with the Public Utility Commission of Oregon since 2013. I am currently a Senior Utility Analyst in the Rates and Telecommunications Section of the Rates, Safety and Utility Performance Program. My responsibilities include leading research and providing technical support on a wide range of technical and policy issues for water and telecommunications companies. I have analyzed and addressed numerous telecommunications issues including special contracts, promotional concessions, tariff changes, price listings, numbering issues, service abandonment, property sales, and price plans, and provided testimony in UM 1895. With regard to water, I have analyzed and addressed numerous issues including tariff changes, property sales, affiliated interest transactions, financing requests, revenue requirement calculations, cost of service, rate spread, and rate design. I have also served as case manager and provided testimony in UW 163, UW 166, UW 173, UP 384, UW 176, UW 181, UW 189, UW 191, UW 192, UW 195, UW 196, and UW 197. With regard to energy, I have provided testimony in UE 426.

CASE: UG 490
WITNESS: STEPH YAMADA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2002

NW Natural's
Non-Confidential
DR Responses

April 18, 2024

Staff/2002
Yamada/1

NW Natural®

Rates & Regulatory Affairs
UG 490
2024 Oregon General Rate Revision
Data Request Response

Request No.: UG 490 SDR 93

For the Test Year, please provide the breakout between O and M and rate base for all labor expense expressed as percentages. If applicable, please also provide the breakout for all labor expense between Total Company and Oregon expressed as a percentage.

Response:

Test Year labor expenses expressed as percentages:

O&M	64.9%
Capital	35.1%

Oregon Test Year labor expense represents 88.7% of Total Company labor expense.

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 142

NW Natural/1000, Rogers/13 states, "The Company is proposing to recover $9,340,431 in total at-risk pay for NBU employees in this rate case."

a. Please provide the underlying data for this information. Please provide all data in electronic workbook format with all cell formulae and references intact.

b. Please reconcile this figure with the Oregon-specific test year figure for incentives shown in the Company's highly confidential response to SDR 92.

c. Please provide the Company's proposed incentives separated by incentive type and employee type (exempt, nonexempt, etc.). Please also provide the total Company vs. Oregon amounts.

d. Does the Company's proposed incentives total of $9,340,431 include the stock purchase plan and incentive plan expenses described in NW Natural/1400, Davilla/17, lines 7-13? Please separately state the amount attributable to each.

Response:

a) See UG 490 OPUC DR 142 Attachment 1 for calculations and references for the $9,340,431 identified as at-risk pay. Please note that the $197,173 of expense for Non-Officer Employee Stock Purchase Plan (ESPP) was inadvertently categorized as at-risk pay when in fact employees have the option to opt out at any time. The total at-risk pay in this case is $9,143,258 which, when added to the $197,173 of expense for Non-Officer ESPP, equals the $9,340,431 for which the Company is seeking recovery in this rate case.

b) UG 490 OPUC DR 142 Attachment 1 identifies the items and amounts included in SDR 92.

c) UG 490 OPUC DR 142 Attachment 1 breaks out between exempt and non-exempt. Exempt excludes Officers as no incentive compensation for Officers is

included in this case. Non-Officer ESPP is not identified as either exempt, non-exempt or union. In Attachment 1 the full amount of Non-Officer ESPP is shown in the exempt column.

d) Yes, the difference between SDR 92 amount and the $9,340,431 in testimony is due to the stock purchase plan, ESPP and long-term incentive compensation amounts. Those are identified separately in Attachment 1.

Staff/2002
Yamada/4

NW Natural's Attachment 1 provided in response to Staff's DR 142 is available in electronic spreadsheet format only.

Staff/2002
Yamada/5

NW Natural®

Rates & Regulatory Affairs
UG 490
2024 Oregon General Rate Revision
Data Request Response

Request No.: UG 490 SDR 92

For the Test Year and the preceding 4 calendar years, please provide (on a Total Company basis), a summary table (using the categories and format shown below) that includes the number of FTE's (exclude FTE's created by overtime hours) and the actual paid cash compensation broken down between base wages or salaries, overtime, and incentives or bonuses. For any calendar year included in this request for which actual data is not available for the entire calendar year, please create a calendar year using the available actual data combined with the forecast applicable to the rest of the year.
Please note which months and figures are associated with both the actual and forecast data.

Year: 2XXX		Actual (Unadjusted) Paid Cash Compensation			
Category	Total Company □FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers					
Exempt					
Nonexempt					
Union					
Total					
□Please Exclude Full-Time Equivalent (FTE) Created by Overtime					

Response:

Please see Highly Confidential UG 490 SDR 92 Attachment 1. This attachment was previously filed as non-confidential, however due to on-going labor negotiations the union wage information for 2024-2025 has been protected and refiled as Highly Confidential.

O&M MODEL - UTILITY ONLY

Test Year: 11/01/2024 - 10/31/2025 (UTILITY)

	Total Company FTEs	Base Wages or Salaries	Overtime	Incentive or Bonus	Total	Oregon
Officers	12.4	$ 5,653,610	$ -		$ 5,653,610	88.1%
Exempt	560.4	$ 73,478,935	$ -	$ 9,092,849	$ 82,571,783	88.7%
Nonexempt	10.5	$ 844,279	$ 5,910	$ 59,258	$ 909,447	88.7%
Union	599.6	$ [redacted]				88.7%
Total	1,183.0	$ [redacted]				

1st Year prior to Test Year: 01/01/2023 - 12/31/2023
(9 months actual + 3 months projected)

	Total Company FTEs	Base Wages or Salaries	Overtime	Incentive or Bonus	Total	Oregon
Officers	11.9	$ 4,661,662	$ -	$ 2,839,198	$ 7,500,859	88.1%
Exempt	520.3	$ 66,132,497	$ -	$ 9,671,964	$ 75,804,461	88.7%
Nonexempt	10.2	$ 789,820	$ 1,400	$ 65,926	$ 857,145	88.7%
Union	556.1	$ 48,599,118	$ 6,821,568	$ -	$ 55,420,685	88.7%
Total	1,098.5	$ 120,183,096	$ 6,822,967	$ 12,577,087	$ 139,583,150	

2nd Year prior to Test Year: 01/01/2022 - 12/31/2022

	Total Company FTEs	Base Wages or Salaries	Overtime	Incentive or Bonus	Total	Oregon
Officers	11.6	$ 3,980,558	$ -	$ 2,569,892	$ 6,550,450	90.2%
Exempt	524.1	$ 61,462,624	$ -	$ 9,392,463	$ 70,855,087	90.2%
Nonexempt	11.8	$ 991,749	$ 358	$ 81,258	$ 1,073,364	90.2%
Union	549.6	$ 45,071,630	$ 6,459,647	$ -	$ 51,531,277	90.2%
Total	1,097.0	$ 111,506,560	$ 6,460,005	$ 12,043,613	$ 130,010,178	

3rd Year prior to Test Year: 01/01/2021 - 12/31/2021

	Total Company FTEs	Base Wages or Salaries	Overtime	Incentive or Bonus	Total	
Officers	10.5	$ 3,412,676	$ -	$ 1,995,806	$ 5,408,482	89.7%
Exempt	507.3	$ 57,634,964	$ -	$ 7,639,029	$ 65,273,993	89.7%
Nonexempt	16.1	$ 1,200,650	$ 3,098	$ 82,928	$ 1,286,676	89.7%
Union	592.3	$ 46,634,119	$ 6,495,661	$ -	$ 53,129,779	89.7%
Total	1,126.1	$ 108,882,409	$ 6,498,759	$ 9,717,763	$ 125,098,931	

4th Year prior to Test Year: 01/01/20120 - 12/31/2020					
	Total Company FTEs	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	11.4	$ 3,881,418	$ -	$ 2,243,206	$ 6,124,624
Exempt	485.6	$ 53,216,452	$ -	$ 7,700,559	$ 60,917,011
Nonexempt	15.3	$ 1,109,173	$ 13,489	$ 97,987	$ 1,220,649
Union	592.4	$ 46,104,869	$ 5,589,269	$ 1,118,278	$ 52,812,417
Total	1,104.7	$ 104,311,912	$ 5,602,758	$ 11,160,030	$ 121,074,701

(1)

O&M MODEL - OREGON UTILITY ONLY

Test Year: 11/01/2024 - 10/31/2025 (UTILITY-OREGON)

	Total Company FTEs	Base Wages or Salaries	Overtime	Incentive or Bonus		Total
Officers	10.9	$ 4,982,411	$ -	$ -	(1)	$ 4,982,411
Exempt	497.1	$ 65,175,815	$ -	$ 8,065,357		$ 73,241,172
Nonexempt	9.3	$ 748,875	$ 5,242	$ 52,562		$ 806,680
Union	531.9	$ [redacted]				
Total	1,049.2	$ [redacted]				

1st Year prior to Test Year: 01/01/2023 - 12/31/2023
(9 months actual + 3 months projected)

	Total Company FTEs	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	10.5	$ 4,108,227	$ -	$ 2,502,127	$ 6,610,354
Exempt	461.5	$ 58,659,525	$ -	$ 8,579,032	$ 67,238,557
Nonexempt	9.1	$ 700,570	$ 1,242	$ 58,476	$ 760,288
Union	493.3	$ 43,107,418	$ 6,050,730	$ -	$ 49,158,148
Total	974.3	$ 106,575,740	$ 6,051,972	$ 11,139,635	$ 123,767,347

Numbers above exclude 6.4 FTEs on Leave Without Pay (military, work comp, etc.) they include 0.4 Exempt FTEs, 0.0 Nonexempt FTEs, and 6.1 Union FTEs.

2nd Year prior to Test Year: 01/01/2022 - 12/31/2022

	Total Company FTEs	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	10.4	$ 3,591,522	$ -	$ 2,318,726	$ 5,910,248
Exempt	472.8	$ 55,455,635	$ -	$ 8,474,500	$ 63,930,136
Nonexempt	10.7	$ 894,821	$ 323	$ 73,316	$ 968,460
Union	495.9	$ 40,666,600	$ 5,828,320	$ -	$ 46,494,920
Total	989.8	$ 100,608,578	$ 5,828,643	$ 10,866,543	$ 117,303,763

Numbers above exclude 6.6 FTEs on Leave Without Pay (military, work comp, etc.) they include 1.0 Exempt FTEs, 0.1 Nonexempt FTEs, and 5.5 Union FTEs.

3rd Year prior to Test Year: 01/01/2021 - 12/31/2021

	Total Company FTEs	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	9.4	$ 3,059,693	$ -	$ 1,789,374	$ 4,849,067
Exempt	454.8	$ 51,673,607	$ -	$ 6,848,901	$ 58,522,508
Nonexempt	14.4	$ 1,076,463	$ 2,778	$ 74,350	$ 1,153,591
Union	531.0	$ 41,810,612	$ 5,823,795	$ -	$ 47,634,407
Total	1,009.6	$ 97,620,375	$ 5,826,573	$ 8,712,625	$ 112,159,573

Numbers above exclude 9.1 FTEs on Leave Without Pay (military, work comp, etc.) they include 0.2 Exempt FTEs, 0.1 Nonexempt FTEs, and 8.8 Union FTEs.

4th Year prior to Test Year: 01/01/20120 - 12/31/2020					
	Total Company FTEs	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	10.2	$ 3,464,166	$ -	$ 2,002,061	$ 5,466,227
Exempt	435.2	$ 47,697,906	$ -	$ 6,902,011	$ 54,599,917
Nonexempt	13.7	$ 994,152	$ 12,090	$ 87,826	$ 1,094,067
Union	531.0	$ 41,323,794	$ 5,009,662	$ 1,002,313	$ 47,335,769
Total	990.1	$ 93,480,018	$ 5,021,752	$ 9,994,211	$ 108,495,981
Numbers above exclude 11.3 FTEs on Leave Without Pay (military, work comp, etc.) they include 0.9 Exempt FTEs, 0.1 Nonexempt FTEs, and 10.4 Union FTEs.					

Officer incentive amount included in this Standard Data Request response represents all annual incentive compensation expected but all Officer incentive amounts were excluded in our test year request.

Staff/2002
Yamada/10

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 153

Please provide in table format the Company's customer count by class, for each month, and each year for fiscal years 2020 through 2025, and identify which values are projected values. Please show figures for the total Company vs. Oregon specifically.

Response:

See "UG 490 OPUC DR 153 Attachment 1.xlsx" for Oregon and the total Company monthly customer counts from 2020 through 2025.

Staff/2002
Yamada/11

NW Natural's Attachment 1 provided in response to Staff's DR 153 is available in electronic spreadsheet format only.

Staff/2002
Yamada/12

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 148
Non-confidential data provided in response to SDR 92 shows the following FTEs attributable to officers:

2020	2021	2022	2023	Test Year
11.4	10.5	11.6	11.9	12.4

Please explain why it is necessary to increase officer FTEs from the 2020-2023 average of 11.3 to 12.4 in the Test Year.
Response:

The number of officers can fluctuate from year to year if we have officers resign or retire, and it can take time to find replacements for those positions. Additionally, in late 2022, we did move our Sr Director of Rates and Regulatory to the VP of Rates and Regulatory officer position. This is a position that was an officer position in the past but had been vacant since Spring of 2016.

Staff/2002
Yamada/13

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 155

Regarding payroll taxes,

a. How much does the Company propose to include in this case? Please provide the total Company and Oregon specific amounts.

b. Please explain how they are calculated. Please include the underlying data and calculations in electronic workbook format with all cell formulae and references intact.

c. Where are they included in the Company's rate request?

Response:

a. Projected Total Company payroll expense is $13,982,300 during the Test Year. This is allocated to O&M, Capital, and Non-Utility. The Capital allocated system amount is $4,692,277. The capital is included in project spend in this case and is allocated to many different FERC accounts with varying allocations to OR. The O&M allocated system amount is $8,718,527, and OR allocation is $7,758,059. This is moved out of O&M and to Other Taxes in the Revenue Requirement. The Non-Utility allocated amount is not included in this case.

b. See UG 490 OPUC DR 155 Attachment 1. The calculation for individual pieces of payroll taxes is taken by multiplying payroll dollars applicable to the tax times the tax rate.

c. Capital is included in project spend. The OR allocated expense can be found included in Other Taxes in the Revenue Requirement calculation. See Workpaper UG 490 – Exh. 1700 – WP1 – Revenue Requirements Model, tab Exhibit 1712 – Other Taxes, cell G24.

Staff/2002
Yamada/14

NW Natural's Attachment 1 provided in response to Staff's DR 155 is available in electronic spreadsheet format only.

CASE: UG 490
WITNESS: STEPH YAMADA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2003

NW Natural's
HIGHLY CONFIDENTIAL
DR Responses

April 18, 2024

Staff/2003
Yamada/1

NW Natural®

Rates & Regulatory Affairs
UG 490
2024 Oregon General Rate Revision
Data Request Response

Request No.: UG 490 SDR 92

For the Test Year and the preceding 4 calendar years, please provide (on a Total Company basis), a summary table (using the categories and format shown below) that includes the number of FTE's (exclude FTE's created by overtime hours) and the actual paid cash compensation broken down between base wages or salaries, overtime, and incentives or bonuses. For any calendar year included in this request for which actual data is not available for the entire calendar year, please create a calendar year using the available actual data combined with the forecast applicable to the rest of the year.
Please note which months and figures are associated with both the actual and forecast data.

Year: 2XXX		Actual (Unadjusted) Paid Cash Compensation			
Category	Total Company □FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers					
Exempt					
Nonexempt					
Union					
Total					
□Please Exclude Full-Time Equivalent (FTE) Created by Overtime					

Response:

Please see Highly Confidential UG 490 SDR 92 Attachment 1. This attachment was previously filed as non-confidential, however due to on-going labor negotiations the union wage information for 2024-2025 has been protected and refiled as Highly Confidential.

Staff/2003
Yamada/2

NW Natural's HIGHLY CONFIDENTIAL Attachment 1 provided in response to Staff's SDR 92 is viewable only in Huddle, subject to Modified Protective Order No. 23-480.

A redacted version is included in Exhibit Staff/2002.

CASE: UG 490
WITNESS: STEPH YAMADA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2004

HIGHLY CONFIDENTIAL
Staff Workpapers

April 18, 2024

Staff/2004
Yamada/1

Staff's HIGHLY CONFIDENTIAL workpapers are available in electronic spreadsheet format only.

CASE: UG 490
WITNESS: KEVIN HENNESSY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2100

Opening Testimony
Safety Projects

April 18, 2024

Docket No: UG 490

Staff/2100
Hennessy/1

Q. Please state your name, occupation, and business address.

A. My name is Kevin Hennessy. I am the Natural Gas Engineering and Safety Manager employed in the Utility Safety, Reliability, and Security Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/2101.

Q. What is the purpose of your testimony?

A. I review Daniel Kizer's testimony regarding investments being made by Northwest Natural Gas Company (NW Natural, NWN or Company) for safety-related programs.

Q. Did you prepare any other exhibits for this docket?

A. No.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. NW Natural Safety and Inspection Programs 2

Q. Could there be changes or updates to Staff's position and recommendations?

A. Yes. My testimony represents issues identified to date. My recommendations and issues may change when informed by new data and after reviewing testimony and analysis by other parties.

Docket No: UG 490

Staff/2100
Hennessy/2

ISSUE 1. NW NATURAL SAFETY AND INSPECTION PROGRAMS

Q. Did you review Daniel Kizer's testimony regarding investments being made by Northwest Natural for safety-related programs?

A. Yes. I did.

Q. Did you have any concerns regarding the approach being taken with these programs.

A. Not generally, however certain programs warrant further mention.

Q. Are these programs consistent with the annual Safety Project Plan (SPP) filed by the Company in UM 1900?

A. Yes. Staff appreciates that the Company has created alignment between this portion of the rate case and the Safety Project Plan[1] to provide early indications of future actions and spending.

Q. Which program do you highlight?

A. First, I have concerns regarding the "ILI," Inline Inspection Program.

Q. What is your primary concern?

A. The Company is currently converting transmission lines to ensure the Company can conduct integrity assessments with inline inspections. Mr. Kizer testified the Company incurred significant costs for one of the ILI conversion projects completed in 2022, the P31/P75 McMinnville Trans ILI Project, after it went into service. Specifically, the Company spent an additional $1.4 million to

[1] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Annual Natural Gas Safety Project Plan*, UM 1900, NW Natural's 2024 Oregon Safety Project Plan (September 27, 2023).

address and remediate three sites on the pipeline where the Company could not perform the inline assessment.[2]

Q. What recommendation to you have for the Commission to better control these cost escalations?

A. I suggest the Commission require NW Natural keep additional records and perform research in advance of construction to mitigate such construction overruns or surprises. Since this program just starting, incorporating learning developed in the McMinnville project makes sense.

Q. What other programs do you want to address?

A. Next, I discuss the underground storage-well integrity program, which will be ongoing for the foreseeable future.

Q. What recommendation to you have for the Commission regarding the Company's underground storage and integrity program?

A. I recommend the Commission require that NW Natural develop clear cost estimates "for the life of the facility" and that the Company include these cost estimates in the Company's annual Oregon Safety Project Plan filed in Docket UM 1900.

Q. Do you wish to discuss any other projects?

A. Yes. The last topic I address is the NW Natural's non-hazardous leakage projects.

Q. What is your concern in this regard?

[2] NW Natural/500, Kizer/44-45.

A. It is important to reduce or eliminate such leakage. In both the Safety Project Plan and in NW Natural's testimony it's not clear to me how many facilities have such leaks.

Q. What recommendation to you have for the Commission regarding non-hazardous leakage?

A. I recommend the Commission require that NW Natural capture and provide more detail in the Safety Project Plan, showing starting or prior counts and severity of leaks, the reduction in the count and severity, the estimated methane reduction, and the costs for the year.

Q. Does this conclude your testimony?

A. Yes.

Mini-Review

Gas Stove Pollutants: Consequences on Indoor Air Quality and Health

Barae Jomaa[1], Damiën van Berlo[2] and Héloïse Proquin[2]

[1]*Colonial Chemical EU B.V., Johan Cruijff Boulevard 65, 1101 DL Amsterdam, The Netherlands*
[2]*National Institute for Public Health and Environment (RIVM), Bilthoven, 3721 MA De Bilt, The Netherlands*

Abstract

Gas stoves are prevalent in residences worldwide as they are both reliable and economical. However, there is a growing body of evidence that indicates that they emit significant levels of indoor air pollutants, including nitrogen dioxide (NO_2), carbon monoxide (CO), volatile organic compounds (VOCs) such as formaldehyde, and particulate matter (PM), which pose serious health risks. Studies demonstrate that hourly average NO_2 concentrations in kitchens can exceed 200 µg/m^3, surpassing the World Health Organization (WHO) indoor air quality guidelines. Similarly, CO levels can reach above 34 mg/ m^3, potentially exceeding the WHO guidelines for indoor air quality of 35 mg/m^3 over 1 hour. VOCs and PM add to the pollution burden, with indoor formaldehyde concentrations ranging from 0.18 mg/m^3 to 0.45 mg/m^3 and PM levels reaching over 86 µg/m^3 during gas oven use. These emissions may exacerbate respiratory diseases, such as asthma, cardiovascular and neurological health issues. This review consolidates scientific literature on the health impacts of these gas stove pollutants and discusses mitigation strategies that can effectively reduce exposure.

Keywords

Indoor Air Pollution; Gas Stove Emissions; Nitrogen Dioxide (NO_2); Particulate Matter (PM2.5); Volatile Organic Compounds (VOCs); Health Impacts of Cooking Appliances.

1 Introduction

According to a 2019 estimate by the WHO, household air pollution accounts for approximately 3.2 million deaths annually: the main source of pollution is still smoking, but cooking is the second largest contributor [1]. In developing countries, many people cook on open fire fuelled by kerosene or biomass such as animal dung and crop waste, but the modern gas stove is a source of air pollution as well. Gas stoves are common in households worldwide due to their long track record of reliability and cost-effectiveness. In recent years, these advantages have been faced with increasing concerns in relation to indoor air pollution and the corresponding health risks. Notably, in a recent study it was estimated that 12.7% of childhood asthma cases in the US might be attributed to gas stove use [2]. Another study has shown that benzene is emitted by gas stoves at levels similar to what one would be exposed to when in the presence of a cigarette smoker [3]. The impact on mortality is significant: gas stove-emitted nitrogen dioxide has been estimated to cause around 40,000 premature deaths per year in the EU and UK combined [4]; this is higher than the number of people estimated to perish from second-hand smoke exposure in the EU each year, which is around 24,000 [5], and the number of yearly deaths from car crashes in the EU (20,400 in 2023) [6]. It should be noted that the mentioned statistics only reflect mortality due to nitrogen dioxide emission, which is only one of the harmful substances emitted by gas stoves. This review explores the toxicological effects of gas stove pollutants, including nitrogen dioxide (NO_2), carbon monoxide (CO), volatile organic compounds (VOCs), and particulate matter (PM).

The health impacts of these emissions can be substantial. Both NO_2 and PM are correlated with respiratory issues, such as the occurrence of asthma symptom episodes and decreased lung function [7, 8]. CO exposure can impair oxygen transport due to its ability to react with hemoglobin to form carboxyhemoglobin (COHb), thereby affecting cardiovascular and neurological health over the long term [9]. Formaldehyde contributes to diseases of the respiratory tract as well as cancer, further amplifying public health concerns arising from the continued use of gas stoves [10].

Despite clear health concerns, regulatory standards for gas stove emissions are often insufficient globally. This is aggravated by the nature of the indoor environment: air dilution is minimal compared

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to the outside, and especially in older houses ventilation may hardly occur in the colder seasons.

This review consolidates scientific literature on gas stove emissions and their health impacts then evaluates mitigation strategies to reduce associated risks.

2 Nitrogen dioxide (NO_2)

2.1 Chemical properties and sources

NO_2 is a reddish-brown gas with a sharp odour at high concentrations yet clear and odourless at lower concentrations. The high heat that is generated during the combustion of fuel causes the nitrogen and oxygen in the air to react and form NO_2.

2.2 Exposure

Gas stoves are a notable source of nitrogen dioxide (NO_2). Studies have indicated that hourly average NO_2 levels in kitchens can exceed 200 μg/m^3 [11], which is the 1-hour limit value set by the World Health Organization's (WHO) for indoor air quality [12] (Tab. 1).

2.3 Mechanism of toxicity

NO_2 irritates the respiratory tract and exacerbates conditions such as asthma, particularly in children, through oxidative stress and inflammatory responses [14].

2.4 Epidemiology

A meta-analysis found a 24% increased risk of developing current asthma and 42% increased risk of developing lifetime asthma in children living in homes with gas cooking. Even more, the analysis revealed a 15% increase in current wheeze for the children per 15ppb of NO_2 [14]. NO_2 exposure from gas cooking appliances is estimated to be responsible for approximately 41,000 pediatric asthma cases in the EU and UK [4].

As an oxidant, NO_2 may impair endothelial function by reducing nitric oxide bioavailability, potentially leading to arterial stiffness and inflammation of the vascular endothelium. This process increases the risk of hypertension.

3 Carbon monoxide (CO)

3.1 Chemical properties and sources

CO is a colourless and odourless gas produced by incomplete combustion. Inefficient burners contribute to higher CO emissions [15].

3.2 Exposure

Another substance of concern is carbon monoxide (CO) that is produced by incomplete combustion and can reach levels of ≥30 ppm (ca. ≥34 mg/m^3) indoors [16], potentially surpassing World Health Organization's (WHO) indoor air quality guideline of 35 mg/m^3 over 1 hour [12].

3.3 Mechanism of toxicity

CO competes with oxygen by reacting with hemoglobin to form carboxyhemoglobin, thereby impairing oxygen transport. This can exacerbate respiratory conditions like COPD and diminish immune responses [17].

3.4 Epidemiology

A number of epidemiology studies have focussed on respiratory outcomes including pulmonary function, hospital admissions related to respiratory disease, and asthma and exacerbation of asthma symptoms [18]. As it relates to pulmonary function, ATDSR concluded that the results are mixed and conflicting and it is difficult to sort the effects of CO from the urban air pollutants. The confounding effect of other air pollutant is also present in the outcome of hospital admission related to respiratory diseases. Nonetheless, studies do provide evidence of an association between CO and an increasing risk of respiratory symp-

Tab. 1: OECD air quality guidelines for $PM_{2.5}$ [13] and indoor air quality guidelines for benzene, carbon monoxide, formaldehyde and nitrogen dioxide [12]

Pollutant	Guideline value	Averaging time	Comments
$PM_{2.5}$	5 μg/m^3	Annual average	-
	15 μg/m^3	24 hours	99th percentile (i.e. 3-4 exceedance days per year)
Benzene	No safe level	Not applicable	Lifetime cancer risk at 1 μg/m^3 is 2.2–7.8 in a million. Airborne concentrations with risks: 17 (1/10,000), 1.7 (1/100,000), 0.17 μg/m^3 (1/1,000,000). Unit risk of leukemia per 1 μg/m^3 is 6×10^{-6}.
Carbon monoxide	100 mg/m^3	15 minutes	Not to occur more than once per day (light exercise).
	35 mg/m^3	1 hour	Not to occur more than once per day (light exercise).
	10 mg/m^3	8 hours	Arithmetic mean (light to moderate exercise).
	7 mg/m^3	24 hours	Arithmetic mean (awake and alert, not exercising).
Formaldehyde	0.1 mg/m^3	30 minutes	Arithmetic mean.
Nitrogen dioxide	200 μg/m^3	1 hour	Arithmetic mean.
	40 μg/m^3	Annual average	-

toms that require medical assistance. Furthermore, the association between CO exposure and asthma symptoms is clearer as results show that the odds ratio for asthma diagnosis increase with an increase CO concentration. Schildcrout et al. examined 990 children in North America and showed that a 1 ppm increase in CO concentration was associated with an odds ratio of 1.08 for asthma symptoms [19].

4 Volatile organic compounds (VOCs)

4.1 Chemical properties and sources

VOCs include hazardous compounds, such as formaldehyde and benzene, that are emitted from the combustion of gas during cooking.

4.2 Exposure

Formaldehyde was found to be present at concentrations ranging from 0.18 mg/m^3 to 0.45 mg/m^3 during cooking [20]. The WHO guideline limit for formaldehyde in indoor air is 0.1 mg/m^3 over 30 minutes whereas benzene has no safe level [12]. Gas stoves have been found to emit 2.8 to 6.5 µg/min benzene [3]. Furthermore, VOC concentrations were evaluated in 69 residential houses in Boston and benzene was found to be present in 95% of the samples at mean concentrations of 164 ppbv (parts per billion by volume) (CI:134-196). In comparison, the Environmental Protection Agency (EPA) measured benzene in Boston urban air between 2020 and 2023 and found a median concentration of 0.14 ppbv [21].

4.3 Mechanism of toxicity

VOCs exposure may lead to respiratory issues with some VOCs, including formaldehyde and benzene, causing cancer. Benzene is widely distributed throughout the body after inhalation, and its metabolism produces highly reactive metabolites that contribute to its toxic effects. The primary and most sensitive targets of benzene toxicity are the hematopoietic systems and the immune system [21]. Formaldehyde, on the other hand, primarily affects the respiratory system and is a potent irritant, with prolonged exposure linked to nasopharyngeal cancer and leukemia [10].

4.4 Epidemiology

Exposure to VOC indoors in various, a study in 69 residential houses in Boston found not only methane and ethane but also 296 unique non-methane VOCs of which 21 were designated as hazardous air pollutants like benzene [22]. In the Agency for Toxic Substances and Disease Registry (ATDSR) evaluation, the minimal risk levels (MRL) of benzene were evaluated and showed that after inhalation these risks are dependent on the exposure duration (Tab. 2) [21].

Tab. 2: Minimal Risk Levels (MRLs) for benzene inhalation: Adapted from the ATDSR toxicological profile for benzene [21]

Exposure duration	MRL (provisional)	Critical effect
Acute	0.009 ppm (0.03 mg/m^3)	Reduction in peripheral lymphocyte count and impaired function of bone marrow lymphocytes
Intermediate	0.007 ppm (0.02 mg/m^3)	Delayed immune response of splenic lymphocytes to foreign antigens
Chronic	0.002 ppm (6 x 10^{-3} mg/m^3)	Decreased peripheral lymphocyte count

5 Particulate matter (PM)

5.1 Chemical properties and sources

PM2.5 (PM < 2.5 µm in size) can be formed from fuel combustion and are prevalent during high-temperature cooking. Moreover, combustion processes can readily generate ultrafine particulate matter (UFPM), with a diameter of <0.1 µm. The presence of extremely small nanoparticles with a particle size in the range of 1–3 nm, referred to as atmospheric nanocluster aerosol, has been associated with cooking episodes [23]. However, it should be noted that frying meat or vegetables generates indoor particulate matter regardless of whether a gas or electric cooker is used.

5.2 Exposure

Gas oven usage contributes significantly to PM2.5 emissions, with concentrations exceeding 86 µg/m^3 over one hour [24]. The World Health Organization's (WHO) air quality guideline is set at 15 µg/m^3 for a 24-hour average [13] and while a 1-hour limit is not set, high short-term peaks can meaningfully elevate daily exposure levels [13]. When considering even smaller particles (ultrafines/nanoparticles), it has been shown that as much as 90% of total exposure to ultrafine particles occurs in the indoor environment [25]. Extremely small (1–3 nm) nanoparticle numbers of 10^5 to 10^7/cm^3 have been measured in the indoor air during propane gas cooking episodes [23]. The highest levels of particle emission were produced during the self-cleaning cycle of stoves.

5.3 Mechanism of toxicity

PM2.5, consisting of small particles, penetrates lung tissue and can cause inflammation and can exacerbate cardiovascular conditions. This can be made worse by hazardous substances that adsorb onto the surface of PM. The smallest particles, in the nano range, can cross the blood-lung barrier, migrate into the systemic circulation and thereby reach organs distal to the lung [26].

5.4 Epidemiology

In a great number of epidemiological studies, associations between particulate matter air pollution and a broad range of adverse health effects have been found [27–29]. The adverse impact on human health included cardiovascular (e.g., cardiac arrhythmia, increased chance of stroke and cardiac arrest) and respiratory (e.g., decreased lung function, exacerbation of asthma, airway irritation) health effects as well as overall mortality. The WHO estimates that PM air pollution contributes to 800,000 premature deaths each year, which means it is the 13th leading cause of mortality (worldwide). Associations between exposure and adverse health effects were stronger for smaller particle fractions, i.e., PM2.5 and PM0.1 (UFP) [30].

6 Outlook and conclusion

Addressing the health risks of gas stove emissions requires an integrated approach combining a transition towards electric stoves, improved ventilation for gas powered stoves, and comprehensive reg-

ulations. Public awareness and financial incentives may prove to be essential for creating healthier indoor environments and reducing the global burden of disease associated with indoor air pollution.

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Association between income, employment status, and asthma outcomes: a systematic review and meta-analysis

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Summary

Background Health inequalities are deeply entrenched in society, and finding ways to reduce these, therefore, represents a major health policy challenge. Focusing on the two highest weighted Index of Multiple Deprivation domains, namely income and employment, we sought to synthesise the evidence on the association between these major determinants of socioeconomic status and asthma outcomes.

Methods In this systematic review and meta-analysis, we searched key concepts related to employment, income, and asthma outcomes using Medline and Embase for studies published between January 1, 2010 and April 3, 2025. Studies were eligible for inclusion if they were in English and described an association between income and/or employment and asthma outcomes, including exacerbations, hospital admissions and mortality, in people with asthma. Risk Of Bias In Non-randomized Studies–of Exposures (ROBINS-E), Risk of Bias (RoB) and adapted RoB tools were used to assess the risk of bias in the included studies. Using the restricted maximum likelihood method, we meta-analysed the rate of exacerbations and explored heterogeneity between age-related population groups: children (under 18 years) and adults (18 years and older). This study was registered with PROSPERO, CRD42024527300.

Findings We identified 4153 potentially eligible studies, of which 3141 were screened. 30 studies met the inclusion criteria, with most having a low risk of bias. 19 studies reported income as the exposure and exacerbation as the outcome, of which ten were included in the meta-analysis. People in the lowest income group were more likely to experience an asthma exacerbation than those in the highest income group: OR 1.25; 95% CI 1.13–1.37 overall and when stratified by age: children (1.36 [1.23–1.50]) and adults (1.19 [1.05–1.33]). Only three studies investigated the role of unemployment and were narratively synthesised. While unemployment was associated with increased emergency care visits, its role in predicting exacerbations was less clear.

Interpretation There is a need for upstream interventions aiming to reduce income inequalities and to investigate their impact on reducing asthma inequalities.

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Keywords: Asthma; Income; Employment; Exacerbations; Admissions; Mortality; Inequalities; Socioeconomic status; Deprivation; Index of multiple deprivation; Domains; Material disadvantage

Introduction

Addressing the impact of deprivation on asthma outcomes has been identified as both a research and health policy priority in the UK.[1] An estimated 5.4 million people have asthma, approximately 8 in every 100, placing the UK among the countries with the highest asthma prevalence worldwide.[2] The UK also has one of the highest asthma death rates for 5- to 34-year-olds in Europe.[3] The inequalities over the last decade due to austerity, poverty and COVID-19 have contributed to

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Research in context

Evidence before this study

Embase and MEDLINE (via the OVID interface) were used to identify previous systematic reviews and meta-analyses published in English from 2010 until 2025 on the association between socioeconomic status and asthma outcomes. The search terms deployed were: ((asthma) AND (mortality OR *admissions OR exacerbations OR hospitali?ations) AND (socioeconomic status OR ses) AND (inequalities OR deprivation OR imd OR index of multiple deprivation) AND (systematic review OR meta-analysis)). Two previous studies were identified. One study investigated socioeconomic status as a whole and by specific domains, such as education and employment, and included studies published between 2000 and 2005. The main findings revealed that lower socioeconomic status was associated with more secondary care healthcare utilisation. The other study focussed on asthma prevalence and allergies, with the former being associated with a lower socioeconomic position (an indicator of socioeconomic status) and the latter being associated with a higher socioeconomic position.

Added value of this study

This is an up-to-date review of the role of socioeconomic inequalities in asthma outcomes for children and adults from 2010 to 2025. Amid regional and global economic and political challenges, this timely review focuses on the two highest weighted components of the Index of Multiple Deprivation (IMD) domains, income and employment, and synthesises these specific factors contributing to socioeconomic status and the association with asthma outcomes. The association was assessed overall and by children and adults separately, indicating that lower income is associated with a higher risk of asthma exacerbations in children and adults.

Implications of all the available evidence

Lower income and unemployment reflect the material disadvantage (the lack of income, goods and services), which can have synergistic effects on poorer asthma outcomes in four ways: 1) the high costs of healthy living; 2) indoor and air outdoor pollution and loss of protective factors; 3) the pathobiology of poverty; and 4) inverse care law. Addressing the material disadvantages is paramount to improving widespread disparities and, as such, requires a multipronged approach. Researchers will need to investigate further the underlying mechanisms at IMD domain level, including the direct role of unemployment and income on hospital admissions and mortality in a heterogeneous adult population. Clinicians should recognise and consider options to mitigate these material disadvantages that manifest in the clinical pathway and impact outcomes. Policymakers should consider policies, such as better housing conditions and unemployment-related stress, targeting the worst deprived groups to improve outcomes and reduce long-term inequalities.

over a million premature deaths and are likely to have led to poorer asthma outcomes, notably in management, in the most deprived deciles.[4–6] Asthma costs the UK health service an estimated £1.1 billion annually, with almost three-quarters spent on providing primary care services (60% prescribing and 14% consultations).[7]

England's National Health Service (NHS) launched the Core20PLUS5 in 2021 as part of its 10-year Long Term Plan.[8] This initiative aims to tackle healthcare inequalities in the most deprived IMD quintile (Core20) among the most vulnerable (PLUS) based on five key clinical outcomes requiring 'accelerated improvement', including chronic respiratory disease.[9]

The role of socioeconomic inequalities in asthma care and outcomes is well-documented in the literature.[10–12] Socioeconomic status (SES), the most common measure of socioeconomic inequalities, is considered a social determinant of health and a risk factor for worse asthma outcomes.[13] Previous systematic reviews have reviewed the association between SES broadly and asthma prevalence and allergies as well as health care utilisation, exacerbations and mortality.[14,15] However, SES is a social construct encompassing many factors.[16] To that end, SES is most commonly proxied by the Index of Multiple Deprivation (IMD).[17] IMD, last recorded in 2019, comprises seven unevenly weighted domains, i.e., income (22.5%), employment (22.5%), health (13.5%), education (13.5%), crime (9.3%), barriers to housing and services (9.3%) and living environment (9.3%).[18] As the interest is on where to improve and what can be modified, it is important to tease out the components of IMD, starting with those most highly weighted, namely income and employment.

No previous systematic reviews have been conducted focused on the association between employment/income domains of socioeconomic status and asthma outcomes. We sought to critically assess and synthesise the evidence on the association between income and employment as the two key contributors to SES and asthma outcomes from 2010 to 2025.

Methods

This systematic review is reported following the Preferred Reporting Items for Systematic Reviews and Meta-Analyses (PRISMA) 2020 statement and its checklist (Supplementary material Table S1).[19] The

protocol was documented and registered in the International Prospective Register of Systematic Reviews (PROSPERO) (CRD42024527300). Ethical approval and participant consent were not required because we analysed data from published studies. Health Data Research United Kingdom's (HDR-UK) Patient and Public Involvement and Engagement (PPI) were consulted on the conception, approach and search strategy.

Search strategy and selection criteria

Embase and MEDLINE (via the OVID interface) were the bibliographic databases selected for the systematic review, as they provided the scientific literature in public health and biomedical sciences with the most relevant and 'unique' references.[20,21]

A preliminary search was conducted on Embase and MEDLINE on March 7, 2024, to validate the concept and prevent redundancy in research efforts.[22] Once the search was completed, the results were reviewed to verify the concepts and ensure a sufficient collection of relevant studies for review. The search terms were refined for the next search and reviewed iteratively until the results accurately captured the research question and only included studies that covered search terms in the titles and abstracts, such as generic terms of the main exposures (economic, deprivation, employment) and observable asthma outcomes from diagnosed asthma patients (admissions, exacerbations and mortality). The search terms were finalised on April 3, 2025. The search terms included English language publications from January 1, 2010, to April 3, 2025. The search strategy was devised by ZG, HW and JKQ (clinician) (Supplementary material Table S2a–c).

The Population, Intervention, Comparator, Outcome, and Study (PICOS) framework was employed to formulate the eligibility criteria (Supplementary material Table S3).[23] Outcome measures included binary, count, rates or time to (first) event, thus reporting odds ratio (OR), risk ratio (RR), incidence rate ratio (IRR) or hazard ratio (HR).

The RIS files of the databases were exported to Covidence to automatically identify and remove duplicates for screening the titles and abstracts.[24] To minimise the risk of error/bias, multiple independent reviewers (IK, EM, AMA, and AT) assessed the titles and abstracts of the retrieved studies according to the eligibility criteria. In cases of disagreement, a referee was consulted (HW). Then, the full text of the remaining studies was screened to determine its relevance to the research question and ensure that none of the exclusion criteria were present. Justification was provided for the excluded studies (Supplementary material Table S4). The PRISMA flow diagram illustrates all the steps in the selection process (Fig. 1).

Data from the full-text studies were extracted from Covidence to outline the study's main characteristics, including exposure, population, outcomes, sociodemographic covariates, body mass index (BMI), smoking, and key findings (ZG, lK, EM, AMA, and AT). Any discrepancies were discussed between the two sets of initial reviewers, and where an agreement could not be reached, a referee was consulted (HW).

Three risk-of-bias tools for eligible studies were used depending on the study design. ROBINS-E was used to evaluate the risk of bias in observational studies.[25,26] The Risk of Bias (RoB 2) was used for randomised control trials.[27] For cross-sectional studies, an adapted RoB domains framework was used.[28,29] After completing the domains, an overall judgement was made (low, moderate or high) and reported in the review. Two reviewers (ZG, HW) independently assessed the risk of bias in all included studies and completed the assessment tool in Word (Supplementary material Table S5a–c).

Data analysis

Data were pooled using random-effects meta-analysis using Stata (version 18) based on comparable exposure, outcomes, covariates and methodology.[30] Forest plots illustrated the heterogeneity between studies, where the I^2 statistic >50% indicated a substantial impact of heterogeneity.[31] Since odds ratios have favourable mathematical properties, meta-analyses were based on odds ratios.[32]

Ad-hoc transformations were applied to selected unit effect measures to allow comparisons based on a derivation of the conversion formula (Supplementary material Appendix S1).[33,34] We estimated the baseline risk for studies reporting HR. In Cardet et al.,[35] β coefficients were reported from the structural equation model predicting the direct association between low SES (latent variable) and asthma-related hospitalisations (0 or 1+). While the paper did not specify whether the structural equation model was probit or logit, it was more likely to be probit because the β coefficients are reported by standard deviation. From Amemiya's study,[36] probit estimates can be transformed to log odds by a factor of 1.6 and then exponentiated to obtain approximate odds ratios and 95% confidence intervals. Renzi-Lomholt et al.[37] reported the odds ratio for exacerbations in the least deprived compared to the most deprived (reference category). In contrast, the other studies had the least deprived group as the reference category. For consistency, the odds ratio and 95% confidence interval were transformed by taking the inverse for quantitative aggregation.[33,38]

The overall effect size was estimated using a random-effects (RE) model. The weighting of the RE model was based on the inverse of the total variance. The estimator for between-study variability was based on the Restricted Maximum Likelihood (REML) method to obtain an unbiased, non-negative estimate of between-study variability.[39] Subgroup analysis was also performed to explore heterogeneity between age-related population groups (patients below 18 compared to patients at least 18 years old).

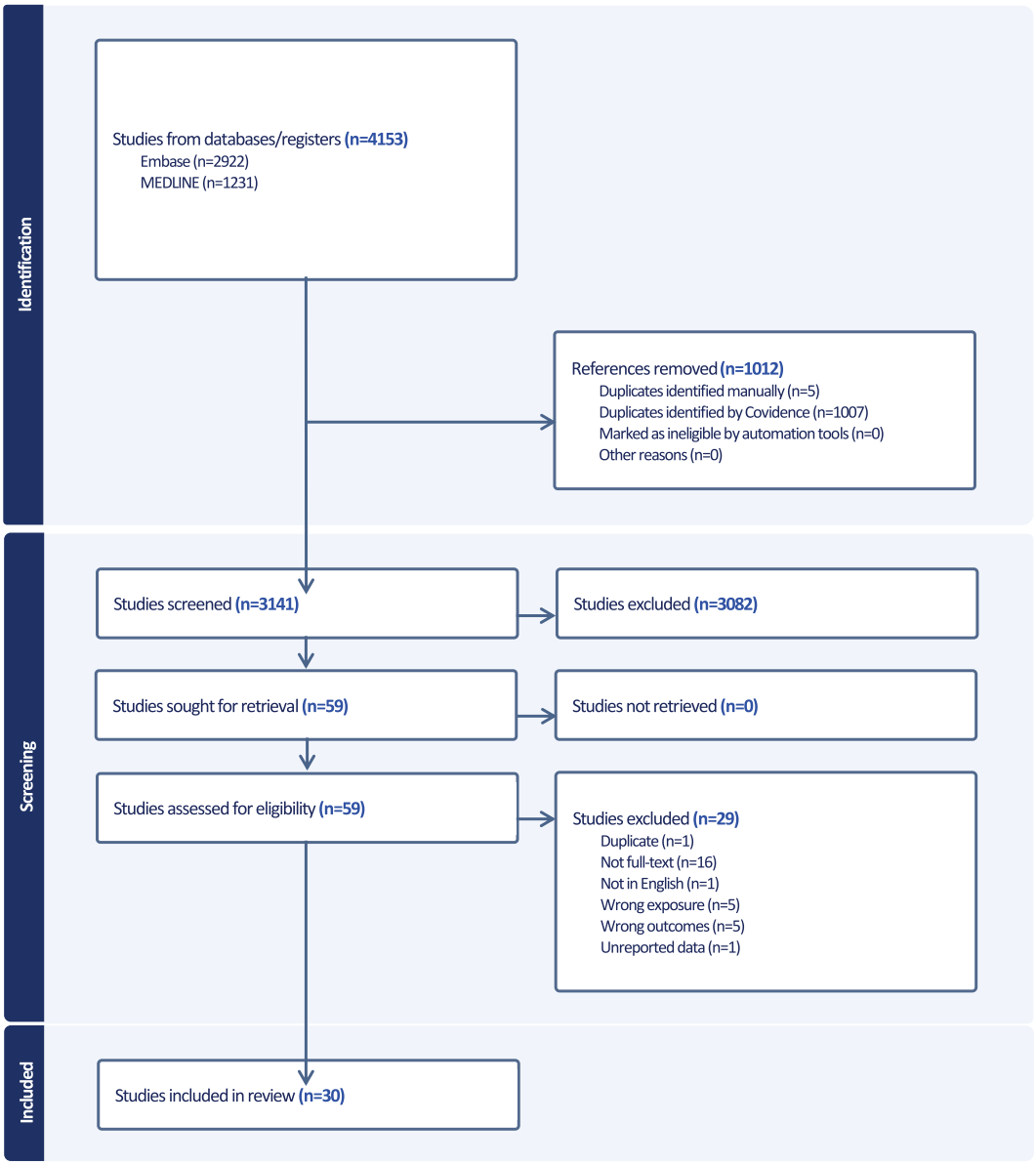

Fig. 1: **PRISMA flow diagram of study screening and selection.**

Role of the funding source

The funder of the study had no role in study design, data collection, data analysis, data interpretation, or writing of the report.

Results

3632 studies were identified, 2583 from Embase and 1049 from MEDLINE (Fig. 1). After removing duplicates (1012 articles), 3141 articles were screened based on their titles and abstracts. 59 articles were included in the full-text screening, of which 29 were excluded (Supplementary material Table S4). Therefore, 30 studies were included in the systematic review and meta-analysis.[35,37,40–67]

Studies were conducted in five different countries: USA (n = 18; 60%), UK (n = 7; 23%), Canada (n = 3, 10%), France (n = 1; 3%) and Denmark (n = 1; 3%) (Table 1). The publication dates of the included studies ranged from 2010 to 2025, with most papers published in 2024 (n = 9; 30%). Analyses were generally of observational design (n = 29; 97%), with cohort studies (retrospective, prospective or population-based) the most common. One study was both a cross-sectional and longitudinal study.[65]

Studies either had measured income per se as an exposure (n = 15; 50%) or as part of a deprivation index

Study	Country	Population	Study type	Main exposure(s)	Main outcome(s)	Variable(s)	Definition(s) or measurement(s)	Main findings[a] (95% CI)
Disano et al. (2010)[43]	Canada	46,173 urban dissemination areas	Descriptive	Institut national de santé publique du Québec (INSPQ) Deprivation Index for health	Age-standardised hospital admissions rates for the treatment of ACSCs (COPD, diabetes and asthma in children)	Count	Number of ambulatory care sensitive conditions related hospital admissions	• Low INSPQ: 270 per 100,000 • High INSPQ: 161 per 100,000
Law et al. (2011)[55]	USA	238,678 adults	Cross-sectional (prevalence)	The ratio of family income to federal poverty level	Asthma-related emergency room or urgent care center visit in the past 12 months	Binary (yes/no)	Patient answered "yes" to the two questions: 1. "During the past 12 months, have you had an episode of asthma or an asthma attack?" 2. "During the past 12 months, have you had to visit an emergency room or urgent care center because of asthma?	OR = 1.32[a] (1.03–1.68)
Ungar et al. (2011)[44]	Canada	490 children	Cohort (retrospective)	Child's family socioeconomic and demographic characteristics	Asthma exacerbations (hospitalisations and emergency department visits)	Count	A count of urgent visits (hospitalizations and ED visits) during 1-year follow-up, where an ED visit that resulted in a hospital admission was counted as a single exacerbation	β = −0.33[a] (−0.64/-0.014)
Auger et al. (2013)[56]	USA	601 children	Cohort (prospective)	Total annual household income	(Time to) readmission for an acute asthma exacerbation	Event time	Admission diagnosis recorded as acute asthma exacerbation with evidence based clinical pathway for acute asthma care by the admitting physician.	HR = 1.82[a] (0.78–4.23)
To et al. (2014)[41]	Canada	Asthma prevalent population (unspecified)	Cohort (population-based)	Ontario Marginalisation Index (ON-Marg) (deprivation quintiles)	Asthma-specific (or underlying) mortality	Count	• Asthma-specific mortality: cases with asthma listed as the primary cause of death determined via International Classification of Diseases (ICD-9) codes • Asthma-contributing mortality: one of the secondary causes of death determined via International Classification of Diseases (ICD-9) codes	Asthma-underlying or specific mortality: • Poisson Rate Ratio = 1.60[a] (1.16–2.20) Asthma-contributing mortality: • Poisson Rate Ratio = 1.34[a] (1.10–1.64)
Zhang et al. (2017)[42]	USA	5535 children (aged 2–17)	Cohort	Income (Low: <$35,000, Middle: $35,000–$75,000, High: ≥$75,000)	Emergency room (ER) visits (self-reported measures of one or more ED visits in the past 12 month)	Binary (yes/no)	ED visit status was recorded in response to: "During the past 12 months, has {child's name} had to visit an emergency room or urgent care center because of {his/her} asthma?"	Prevalence ratios = 0.47[a] (0.28–0.80)
Gupta et al. (2018)[57]	England (UK)	14,830 recorded asthma deaths of children and adults 542,877 emergency asthma admissions over the age of 5	Cross-sectional	English IMD	Asthma mortality and hospital admissions	Count (hospital admissions and mortality)	• The numbers of registered deaths in England with underlying cause of asthma (International Classification of Diseases Version 10 (ICD-10) J45 and J46) recorded on the death certificate. • Numbers of emergency admissions with a primary diagnosis of asthma	Mortality: • 5–44: IRR = 0.81[a] (0.69–0.96) • 45–74: IRR = 1.37[a] (1.24–1.52) • 75+: IRR = 1.30[a] (1.22–1.39) Admissions: • 5–44: IRR = 3.34[a] (3.30–3.38) • 45–74: IRR = 2.01[a] (1.98–2.05) • 75+: IRR = 1.43[a] (1.39–1.47)

(Table 1 continues on next page)

Study	Country	Population	Study type	Main exposure(s)	Main outcome(s)	Variable(s)	Definition(s) or measurement(s)	Main findings[a] (95% CI)
(Continued from previous page)								
Mazalovic et al. (2018)[45]	France	255 children and adult patients	Cohort (ancillary, prospective)	SES (derived from the French National claims database and GPs computerised questionnaires)	Asthma exacerbations (followed by measures on managing asthma exacerbations)	Count	The occurrence of at least one of the following asthma-related events: OCs courses, unplanned medical visits to a GP or a hospital emergency department, hospitalization, or death	• Mann–Whitney test: p = 0.38 • OR = 0.27 (0.09–0.84)
Cardet et al. (2018)[40]	USA	381 adult participants	RCT	SES correlates: (1) Income group (low: <$50,000 vs. high) (2) Household educational level (<Bachelor's Degree) (3) Perceived Stress Level (≥20)	Asthma exacerbations (requiring systemic corticosteroids)	Count	Satisfying both the treatment failure criteria and ≥1 of the following: • Failure to respond to rescue algorithm within 48 h • FEV1 ≤50% of baseline or <40% of predicted (2 consecutive measurements) • Levalbuterol use of ≥16 puffs/day for 48 h • Exacerbation per physician opinion • Systemic corticosteroid treatment for asthma *NB: The treatment failure is defined as ≥1 of the following:* • *Peak expiratory flow ≤65% of baseline (2 of 3 consecutive measurements)* • *FEV1 ≤80% of baseline (2 consecutive measurements)* • *Levalbuterol dose increase by ≥8 puffs/day for 48 h (vs. baseline)* • *Additional ICS or systemic corticosteroid treatment* • *Asthma-related emergency department visit or hospitalization with systemic corticosteroid treatment* • *Participant dissatisfaction with treatment* • *Physician clinical safety judgment*	Poisson Rate Ratio = 1.80[a] (1.10–3.10)
Grunwell et al. (2018)[46]	USA	579 children (6–18 years old)	Cohort (retrospective)	Income (below and above the poverty line)	PICU (Paediatric Intensive Care Unit) admission	Binary (yes/no)	Admitted to the hospital for an asthma exacerbation in the last 12 months	OR = 1.28[a] (1.02–1.61)
Eum et al. (2019)[47]	USA	2093 children (2011: 1070 & 2015: 1023)	Cross-sectional	SES (median household income, residents' education level, health insurance coverage, and unemployment rate)	Children's asthma-related emergency department (ED) utilisation	Count	The total count of daily pediatric asthma-related ED visits based on primary diagnosis code (International Classification of Diseases, 9th Revision (ICD-9) 493; ICD-10 J45)	Median household income: • 2011: RR = −0.03[a] (−0.04/−0.02) • 2015: RR = −0.03[a] (−0.03/−0.02) Unemployment: • 2011: RR = −0.01[a](−0.04–0.03) • 2015: RR = −0.01[a] (−0.04–0.03)

(Table 1 continues on next page)

Study	Country	Population	Study type	Main exposure(s)	Main outcome(s)	Variable(s)	Definition(s) or measurement(s)	Main findings[a] (95% CI)
(Continued from previous page)								
Seibert et al. (2019)[48]	USA	342 adults (18–41 years old)	Cohort (longitudinal)	Self-reported household income category (< $15,000, $15,000–$29,999, $30,000–$50,000, >$50,000)	Asthma-related emergency department (ED) visits and hospitalization	Binary (yes/no)	Same-day care (ED visit, hospitalization, or any same-day medical visit such as a walk-in clinic or urgent care center) in the previous 3 months	Asthma-related ED visit: • OR = 0.88[a] (0.80–0.97) Asthma hospitalization: • OR = 0.94[a] (0.82–1.08)
Brite et al. (2020)[67]	USA	30,452 adults	Cohort	SES defined as (1) Education and income and (2) race/ethnicity	Asthma-related emergency department (ED) visits	Count	The number of asthma-related ED visits determined by the International Classification of Diseases, Ninth Revision, Clinical Modification (ICD-9-CM) and International Statistical Classification of Diseases, Tenth Revision, Clinical Modification (ICD-10-CM) codes as a principal diagnosis or a respiratory condition listed as the principal diagnosis and asthma listed as a secondary diagnosis	β = 11.70 (10.60–12.70)
Molina et al. (2020)[54]	USA	664 children	Cross-sectional (retrospective)	Alabama area deprivation index (proxy for neighbourhood deprivation)	Severe hospitalization (requiring continuous albuterol or intensive care unit care)	Binary (yes/no)	Intensive care unit care or continuous albuterol	OR = 1.09[a] (0.73–1.63)
Jroundi & Tse (2021)[49]	USA	66,835 children	Cohort (retrospective)	State median household income (quartiles)	Time to asthma-related readmission and time to first asthma-related ED visit date	Event time	The first asthma-related readmission after the hospitalization discharge date	HR = 1.33[a] (1.15–1.53)
Alsallakh et al. (2021)[50]	Wales (UK)	Main study cohort: 106,926 children and adults Asthma mortality analysis: 327,906	Cohort	Welsh IMD quintiles	Asthma-related health service utilisation and asthma-related deaths	Count (hospital admissions and mortality)	Patients with a primary diagnosis of asthma (J45) or status asthmaticus (J46) coded using the 10th Revision of the International Classification of Diseases (ICD-10). Among these, emergency admissions were defined as coming via A&E departments, urgent referrals from GPs, consultant clinics, bed bureaus, or NHS Direct	Asthma-related accident and emergency attendances: • IRR = 1.27[a] (1.10–1.46) Asthma emergency admissions: • IRR = 1.56[a] (1.39–1.76) Asthma-related death: • RR = 1.56[a] (1.18–2.07).
Busby et al. (2021)[51]	UK	127,040 adult patients	Cohort (population-based)	Indices of Multiple Deprivation of their general practice (a proxy measure for individual SES)	Asthma presentation, processes and healthcare outcomes, including exacerbations	Binary (yes/no)	Read code indicating an 'Asthma Exacerbation' or 'Asthma Attack, prescription of acute oral corticosteroids (OCS), or a lower respiratory infection requiring antibiotics	OR = 1.27[a] (1.13–1.42)
Cardet et al. (2022)[35]	USA (including Puerto Rico)	990 adults	Cross-sectional (ancillary)	SES (based on a multidomain, latent variable defined by poverty, education, and unemployment)	Asthma morbidity (exacerbations and Asthma Control Test score)	Binary (yes/no)	Outpatient corticosteroid bursts for asthma, emergency room [ER]/urgent care [UC] visits and hospitalizations	Low SES and hospitalizations: • β = 0.24[a] (0.11–0.38) Low SES and asthma ER/UC visits: • β = 0.03[a] (0.00–0.05) Poverty and additional asthma hospitalisations: • β = 0.48[a] (0.15–0.80) Unemployment and ER/UC visit: • β = 0.03[a] (0.01–0.06)

(Table 1 continues on next page)

Study	Country	Population	Study type	Main exposure(s)	Main outcome(s)	Variable(s)	Definition(s) or measurement(s)	Main findings[a] (95% CI)
(Continued from previous page)								
Mukherjee et al. (2022)[52]	England (UK)	2110 children	Observational	English IMD	Healthcare resource utilisation and severity, including admissions and deaths	Count (hospital admissions and mortality)	Number of deaths in PICU	β = 1.28[a] (1.10–1.49)
Kallis et al. (2023)[59]	England (UK)	898,763 adults (training sample)	Cohort	English IMD	Asthma exacerbation (n = 93,625)	Binary (yes/no)	At least one asthma exacerbation recorded within 90 days from their study start	OR = 1.06[a] (1.04–1.09)
Renzi-Lomholt et al. (2024)[37]	Denmark	29,851 children	Cohort	4 markers of parental socio-economic position (workforce attachment, family disposable income, family highest level of attained education and metropolitan residence)	Uncontrolled, exacerbating, and severe asthma	Binary (yes/no)	Redemption of at least 187.5 mg of prednisolone, severe as asthma related (ICD-10 codes J45, J46, J96, J960 or J969) hospitalisation and near-fatal as intensive care admission with the ICD-10 codes	OR = 0.68[a] (0.58–0.79)
Khalaf et al. (2024)[53]	England, UK	119,611 children	Cohort	English IMD	Asthma exacerbation (general practitioner (GP)-managed (short course of oral corticosteroids (OCS)) or hospital-managed (A&E visit or hospital admission for asthma))	Event time	General practitioner (GP)-managed (short course of oral corticosteroids (OCS)) or hospital-managed (A&E visit or hospital admission for asthma, using International Classification of Disease (ICD)-10 codes J45 and J46	• Age 5–11.9 years: HR = 1.20[a] (1.20–1.30) • Age 12–15.9 years: HR = 1.40[a] (1.20–1.50) • Adolescents: HR = 1.30[a] (1.20–1.50)
Simms-Williams et al. (2024)[58]	UK	1,385,326 children and adults	Cohort	IMD	Asthma-related hospital and intensive care unit (ICU) admissions	Count	Hospital admissions with associated ICD-10 asthma diagnosis codes J45 and J46 as the primary diagnostic code for the admission	Asthma-related hospital admissions: • 5–11 years: IRR = 1.51[a] (1.30–1.75) • 2–17 years: IRR = 1.52[a] (1.22–3.34) • 8+ years: IRR = 1.43[a] (1.33–1.54) Asthma-related ICU admissions: • 5–11 years: IRR = 1.98[a] (1.03–3.79) • 12–17 years: IRR = 2.09[a] (0.88–4.98)[a] • 18+ years: IRR = 1.35[a] (0.96–1.89)
Akinyemi et al. (2024)[60]	USA	1,665,516 adults	Retrospective cross-sectional study	Distressed Communities Index (DCI)	Asthma-related ED visits	Binary (yes/no)	The occurrence of asthma-related ED visits based on diagnostic codes and records indicating asthma-related complaints and treatment	OR = 1.65[a] (1.62–1.69)
Gaietto et al. (2024)[65]	Puerto Rico (USA)	209 'youths' (6–14 and 9–20)	Cross-sectional and longitudinal study	Low annual household income (<$15,000 per year)	Recurrent severe asthma exacerbation based on asthma-related ED visits and hospitalisation	Binary (yes/no)	Visit to the emergency department (ED) or urgent care for asthma or a hospitalization for asthma	OR = 12.25[a] (2.59–57.97)

(Table 1 continues on next page)

Study	Country	Population	Study type	Main exposure(s)	Main outcome(s)	Variable(s)	Definition(s) or measurement(s)	Main findings[a] (95% CI)
(Continued from previous page)								
Scott et al. (2024)[61]	USA	211 individuals	Community-based, cross-sectional study	Perceived financial status, income and occupation	Exacerbation-based (un) controlled asthma: Uncontrolled asthma: ≥2 asthma exacerbations in the past year Controlled asthma: ≤1 or no exacerbations	Binary (yes/no)	Patient answered "yes" to question 1: 1. During the past 12 months, have you had an episode of asthma or an asthma attack?" And reported ≥2/year to question 2: 2. "During the past 12 months, how many asthma episodes or attacks have you had?"	Occupation: • OR = 0.69[a] (0.23–2.05) Perceived financial status: • OR = 0.81[a] (0.27–2.50)
Khalid et al. (2024)[62]	USA	423,140 adult asthma admissions	Retrospective observational study	National quartile for household income	In-hospital mortality (per admission)	Count	Number of deaths in hospital per asthma admission	OR = 0.77[a] (0.51–1.15)
Skeen et al. (2024)[66]	USA	193 children	Cross-sectional study	Child Opportunity Index (COI) 2.0	Exacerbation-prone asthma	Binary (yes/no)	An asthma-related event requiring an unscheduled visit to an emergency department or urgent care facility, overnight hospitalization, and/or course of oral or injectable corticosteroids	COI overall: • OR = 1.19[a] (0.92–1.54) Household income ($5000 increments): • OR = 1.00[a] (0.89–1.12)
Xu et al. (2024)[64]	USA	198,873 adults	Retrospective cohort study	Neighborhood Deprivation Index (NDI)	Acute asthma exacerbation (AAE) and asthma-related emergency department and urgent care (ED/UC) visits in adults with mild asthma.	Count	1. A hospitalization, ED visit, or hospital-based observation with: • A principal discharge diagnosis of asthma or wheezing OR • Specific respiratory conditions being the principal or primary diagnosis, and with either exacerbation or status asthmaticus being the secondary diagnosis 2. A systemic corticosteroid administration in which asthma was the principal or primary encounter diagnosis code or was associated with the systemic corticosteroid order	Acute asthma exacerbation: • RR = 1.27[a] (1.20–1.35) Asthma-related ED visits: • RR = 1.75[a] (1.62–1.88)
Miller et al. (2025)[63]	USA (including Puerto Rico)	15,877 children	Cohort study	Child Opportunity Index (COI)	Asthma with Recurrent Exacerbations	Count	At least two reports of systemic corticosteroid use at any time during the entire follow-up period with each considered an exacerbation event if separated by a minimum of 30 days	Overall COI: • IRR = 1.26[a] (0.99–1.59) Social and economic domain categories of COI: • IRR = 1.22[a] (0.97–1.53)

OR = odds ratio. HR = hazard ratio. IRR = incidence rate ratio. RR = risk ratio. β = regression coefficient. [a]Adjusted.

Table 1: **Study characteristics of the included studies.**

(n = 13; 43%), such as IMD, WIMD, Neighborhood Deprivation Index (NDI), Distressed Communities Index (DCI), Institut national de santé publique du Québec (INSPQ) Deprivation Index and Ontario Marginalization Index (ON-Marg). The remaining two studies measured poverty[35] or perceived financial status.[61] One study assessed the relationship between SES and asthma-related emergency department (ED) visits.[67] In addition to income, three studies (10%) measured employment per se as an exposure and were included in the narrative synthesis.[35,47,61]

The sample size varied between 193 and 1,665,516 patients.[60,66] The percentage of females in the studies ranged from 37% to 83.9%.[35,54] The mean and median age were commonly reported, with similar highest ages: 52.1 years (mean)[51] and 53 years (median).[59] Of the studies that measured ethnicity, white was the largest ethnic group, reaching as high as 97.5%.[51] Studies that reported the BMI categories had most participants in the normal range.[42,45,46,53,58] However, studies reporting the average BMI were between overweight and obese BMI, ranging from 27.8 to 32.3.[40,51] Most patients were non- or never-smokers.[35,45,48,51,58,64]

19 studies (63%) investigated the association between income as a proxy for SES, deprivation or poverty, and exacerbations.[35,37,40,44–46,48,49,51,53–56,59,61,63–66] Generally, studies defined exacerbations by ED visits/hospitalisations or oral corticosteroids (OCS)/hospitalisations, though some studies used both.[53,64,66] Multiple studies defined exacerbations by prescription only: acute OCS,[35] systemic corticosteroid,[63] and OCS or lower respiratory infection requiring antibiotics.[51] Three studies included the following definitions: failure to meet treatment criteria of levalbuterol or systemic corticosteroid and diagnostic tests,[40] medical contact and death,[45] and intensive care admissions and prednisolone.[37] Eight (%) included physician-defined exacerbations,[37,46,49,51,54,56,59,63,66] and six studies (%) relied on self-reported exacerbations.[35,40,45,48,55,61] One study specified physician-defined and hospital-managed exacerbations.[53] One study identified risk factors associated with recurrent severe asthma exacerbations from two visits, by exploring the possible permutations to see whether both the risk factor and outcome changed or 'persisted' in both visits.[65] Depending on the study methods, exacerbations were mainly measured as a binary outcome (yes/no) and reported ORs. Other studies reported exponentiated Poisson coefficients and rate ratios for the exacerbation risk,[44,64] HRs for time to exacerbation,[53,56] and IRRs for childhood asthma with recurrent exacerbations.[63]

Five studies (23%) investigated the impact of SES on the number of hospital admissions.[43,50,52,57,58] General and specific definitions were applied. Alsallakh et al.[50] included asthma admissions per se to distinguish them from emergency admissions, which were defined as "coming via A&E departments, urgent referrals from GPs, consultant clinics, bed bureaus, or NHS Direct". Similarly, Simms-Williams et al.[58] had asthma admissions as a primary outcome and asthma-related ICU admissions as a secondary outcome. Disano et al.[43] and Gupta et al.[57] provided a general definition of hospital admissions, while Mukherjee et al.[52] focussed on the number of paediatric intensive care unit (PICU) admissions. Three of the five studies reported age-standardised rates.[43,52,57]

Five studies (23%) examined the association between SES and asthma mortality.[41,50,52,57,62] Three studies used ICD-9[41] and ICD-10 codes[50,57] to identify asthma as the underlying cause of death. To et al.[41] further established asthma as a secondary cause, defined as asthma-contributing mortality, and Alsallakh et al.[50] also included deaths with any mention of asthma in the definition of mortality. Mukherjee et al.[52] based mortality in PICU on a prediction score from a model known as the Paediatric Index of Mortality version 2 (PIM2). While assessing seasonal variations and differential outcomes in adult admissions for asthma, Khalid et al.[62] reported the association between income and in-hospital mortality using the US National Inpatient Sample database.

Four studies (13%) had more than one exposure and/or outcome, thus reporting multiple associations.[50,52,57,64] Further information on the study covariates and outcomes, including effect sizes and measures, is provided in Supplementary material Table S6a–d.

Most of the studies were assessed using the ROBINS-E tool (n = 19; 63%). Four studies (13%) were deemed at high risk of bias due to confounding (not adjusting for confounding or persistent residual confounding) and selection bias (Table 2). Most studies had a low risk of bias, with uncontrolled or residual confounding as the most common bias. Most studies adjusted for at least two of the three prespecified confounders (age, sex/gender or ethnicity), with seven (%) adjusting for all.[35,49,54,58–60,62,66] Gaietto et al.[65] was assessed using the ROBINS-E tool given the outcome of interest, i.e., the association between a 'persistent' risk factor (income) and 'persistent' recurrent severe asthma exacerbations with persistent defined as having a risk factor and outcome in both visits 1 and visits 2, was reported in the longitudinal model.

Ten of the 19 studies were eligible for a meta-analysis, with half contributing to each population group (Table 3). Seven studies reported ORs, two reported HRs, and one reported β coefficients. The remaining studies had results that were not comparable in terms of age,[53,65,66] exposure,[61] effect measure,[40,44,63,64] and lack of covariate adjustment.[45]

The lowest income group were more likely to be hospitalised or (re)admitted due to an exacerbation than the highest income group, albeit with substantial heterogeneity between studies (OR 1.25 [95% CI

Study	Risk of Bias tool	Risk	Bias
Disano et al. (2010)[43]	RoB (adapted)	High	Did not adjust for confounding
Law et al. (2011)[55]	RoB (adapted)	Low	Missingness and recall bias from survey data
Ungar et al. (2011)[44]	ROBINS-E	Moderate	Uncontrolled or residual confounding and reporting bias
Auger et al. (2013)[56]	ROBINS-E	Low	Uncontrolled or residual confounding
To et al. (2014)[41]	ROBINS-E	Low	Uncontrolled or residual confounding
Zhang et al. (2017)[42]	ROBINS-E	High	Uncontrolled or residual confounding
Cardet et al. (2018)[40]	RoB 2	Low	N/A
Grunwell et al. (2018)[46]	ROBINS-E	Low	Uncontrolled or residual confounding
Mazalovic et al. (2018)[45]	ROBINS-E	High	Did not adjust for confounding
Gupta et al. (2018)[57]	RoB (adapted)	Low	Uncontrolled or residual confounding
Seibert et al. (2019)[48]	ROBINS-E	Low	Uncontrolled or residual confounding
Molina et al. (2019)[54]	RoB (adapted)	Low	Selection bias
Eum et al. (2019)[47]	RoB (adapted)	Low	Uncontrolled or residual confounding
Brite et al. (2020)[67]	ROBINS-E	Low	Uncontrolled or residual confounding
Alsallakh et al. (2021)[50]	ROBINS-E	Low	Uncontrolled or residual confounding
Jroundi & Tse (2021)[49]	ROBINS-E	Low	Uncontrolled or residual confounding
Busby et al. (2021)[51]	ROBINS-E	Low	Uncontrolled or residual confounding and regression dilution
Mukherjee et al. (2022)[52]	RoB (adapted)	Low	Uncontrolled or residual confounding
Cardet et al. (2022)[35]	RoB (adapted)	Moderate	Selection bias and missingness
Kallis et al. (2023)[59]	ROBINS-E	Low	Uncontrolled or residual confounding
Renzi-Lomholt et al. (2024)[37]	ROBINS-E	Low	Uncontrolled or residual confounding
Khalaf et al. (2024)[53]	ROBINS-E	Moderate	Uncontrolled or residual confounding and missingness
Simms-Willliams et al. (2024)[58]	ROBINS-E	Low	Uncontrolled or residual confounding
Akinyemi et al. (2024)[60]	RoB (adapted)	Moderate	Uncontrolled or residual confounding and reporting bias
Gaietto et al. (2024)[65]	ROBINS-E	Low	Selection bias
Scott et al. (2024)[61]	RoB (adapted)	High	Selection bias and other bias (internal validity concerns)
Khalid et al. (2024)[62]	ROBINS-E	Low	Uncontrolled or residual confounding
Skeen et al. (2024)[66]	RoB (adapted)	Low	Uncontrolled or residual confounding
Xu et al. (2024)[64]	ROBINS-E	Low	Uncontrolled or residual confounding
Miller et al. (2025)[63]	ROBINS-E	Moderate	Uncontrolled or residual confounding and selection or temporal bias

Table 2: **Summary of risk of bias in eligible studies.**

1.13–1.37]; I^2 = 75.6%) (Fig. 2). We reject the homogeneity test of study-specific effect sizes ($p < 0.001$). Therefore, we can infer significant heterogeneity between the individual studies. The significance test ($p < 0.001$) suggested that the overall effect size is statistically significantly different from zero.

The subgroup analysis showed no difference in the association between children (1.36 [1.23–1.50];

Study	n/N	Original estimate (95% CI)	Population group	Final/transformed estimate (95% CI)
Law et al. (2011)[55]	2367/238,678	OR = 1.32 (1.03–1.68)	Adults	OR = 1.32 (1.03–1.68)
Auger et al. (2013)[56]	135/601	HR = 1.82 (0.78–4.23)	Children	OR = 1.92 (0.77–5.24)
Grunwell et al. (2018)[46]	170/579	OR = 1.28 (1.02–1.61)	Children	OR = 1.28 (1.02–1.61)
Seibert et al. (2019)[48]	N/A	OR = 0.94 (0.82–1.08)	Adults	OR = 1.06 (0.93–1.22)
Molina et al. (2020)[54]	149/664	OR = 1.09 (0.73–1.63)	Children	OR = 1.09 (0.73–1.63)
Busby et al. (2021)[51]	5732/127,040	OR = 1.27 (1.13–1.42)	Adults	OR = 1.27 (1.13–1.42)
Jroundi & Tse (2021)[49]	9377/66,835	HR = 1.33 (1.15–1.53)	Children	OR = 1.37 (1.17–1.61)
Cardet et al. (2022)[35]	596/990	β = 0.24 (0.11–0.38)	Adults	OR = 1.47 (1.19–1.84)
Kallis et al. (2023)[59]	93,625/805,138	OR = 1.06 (1.04–1.09)	Adults	OR = 1.06 (1.04–1.09)
Renzi-Lomholt et al. (2024)[37]	2353/29,851	OR = 0.68 (0.58–0.79)	Children	OR = 1.47 (1.27–1.72)

The odds ratios presented in the final or transformed estimates originate from binary (yes/no) variables (8 studies) or event time variables (2 studies). Binary (yes/no) variables reported odds ratios (7 studies) and regression coefficients (1 study). Event time variables reported hazard ratios (2 studies). OR = odds ratio. HR = hazard ratio. β = regression coefficient. n = number of exacerbations. N = number of patients.

Table 3: **Studies included for meta-analysis with the absolute, original and final/transformed estimates.**

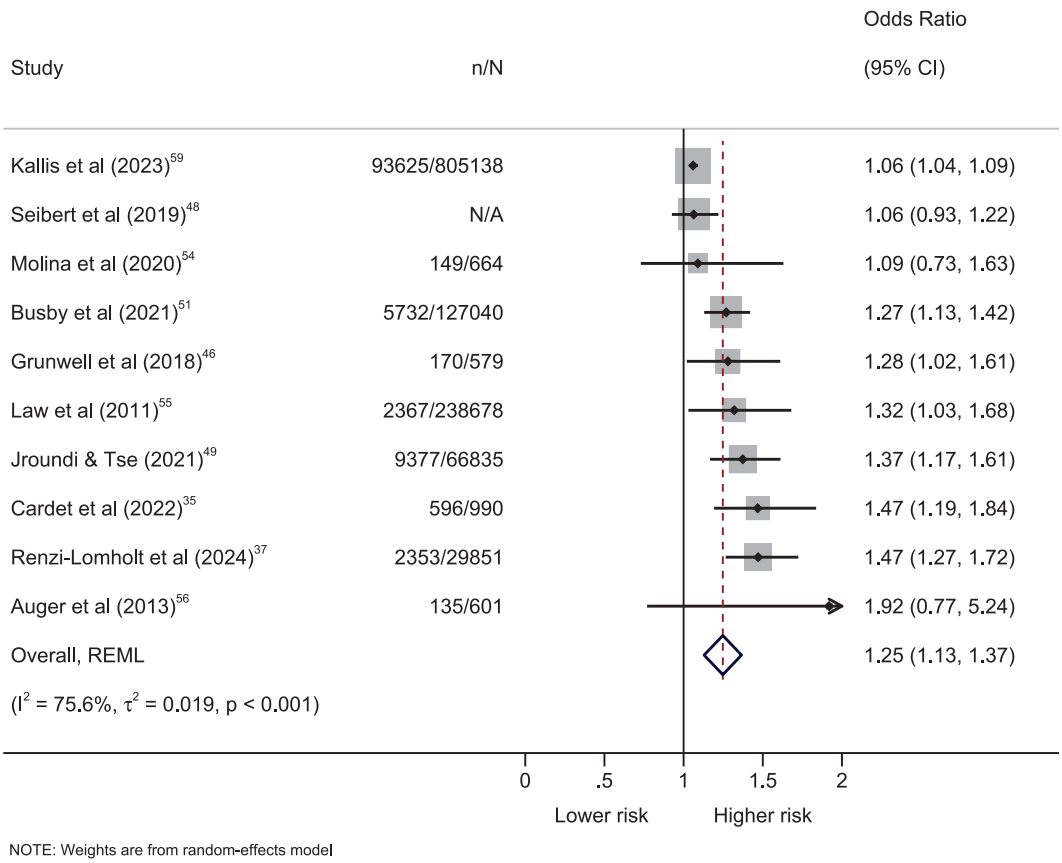

***Fig. 2*: Forest plot of the association between income and exacerbations.** Odds ratios are presented with 95% confidence intervals. The odds ratios presented in the original studies originate from binary (yes/no) variables (8 studies) or event time variables (2 studies). The red vertical line is the average effect estimate. The black vertical line shows no effect. OR = odds ratio. n = number of exacerbations. N = number of patients.

I2 = 0.0%) and adults (1.19 [1.05–1.33]; I2 = 75.1%) (Fig. 3). With the potential impact of heterogeneity greater in adults than in children, we can infer that studies with adults correspond to most of the variability of the effect sizes. The test of group differences indicated no statistically significant subgroup effect (p = 0.076), meaning that the population group does not modify the effect of income on exacerbation.

Two studies investigated the association between employment and EC attendance or ED utilisation, using unemployment as an indicator or component of SES.[35,47] The first study examined the pathways and identified mediating factors in African American/Black and Hispanic/Latinx adults with moderate to severe asthma.[35] Unemployment showed stress-mediated indirect associations with increased healthcare utilisation. Those living in poverty, who were more likely to be unemployed (73.7% vs. 40.8%; p < 0.001), experienced higher rates of asthma hospitalisations (23.6% vs. 14.0%; p < 0.001). Notably, unemployment was the only SES measure showing stress-mediated indirect associations with emergency room/urgent care visits (β 0.03 [95% CI 0.01–0.06]).

The second study was a cross-sectional study on a paediatric asthma cohort in New York.[47] Children living in areas where regional economic development projects were completed during the study period (2011–2015) had lower ED utilisation. The unemployment rate was used as an indicator for the latent SES variable in a spatial regression analysis to account for geographic variation and local economic conditions. While there was a significant decrease in ED utilisation in areas where economic development projects were completed ($\beta_{\text{difference-in-differences}}$-1.526 [SE = 0.686]), this was not directly linked to changes in unemployment rates. The relative risk for unemployment was not statistically significant in 2011 (RR -0.01 [95% CI –0.04–0.03]) and 2015 (–0.01 [–0.04–0.03]), suggesting no evidence of an association between unemployment and asthma-related ED utilisation. However, other SES indicators, namely median household income and health insurance coverage, were key socioeconomic predictors of children's

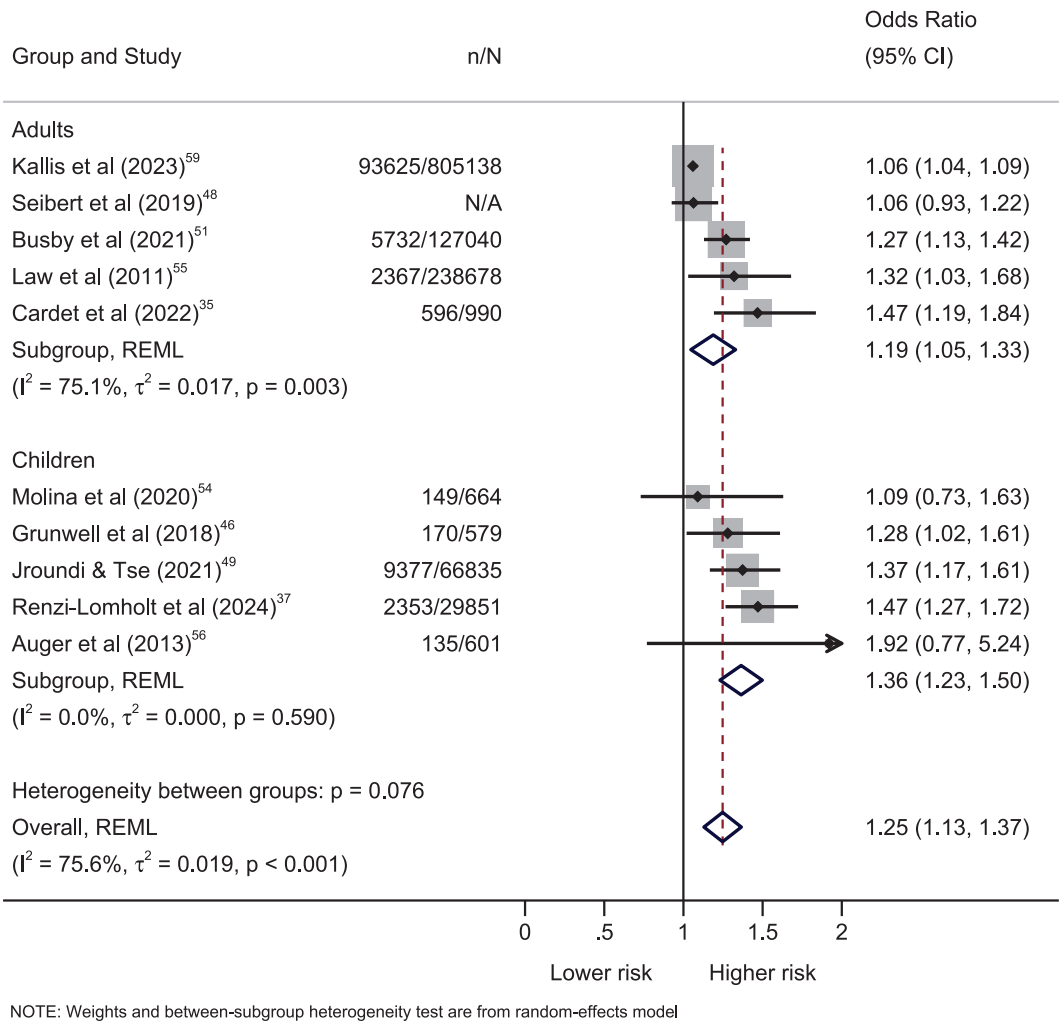

Fig. 3: **Forest plot of the association between income and exacerbations by population group (children and adults).** Odds ratios are presented with 95% confidence intervals. The odds ratios presented in the original studies originate from binary (yes/no) variables (8 studies) or event time variables (2 studies). The red vertical line is the average effect estimate. The black vertical line shows no effect. OR = odds ratio. n = number of exacerbations. N = number of patients.

asthma-related ED utilisation. While unemployment was significantly associated with asthma-related EC utilisation in adult populations, mainly through stress-mediated pathways, its association with paediatric asthma outcomes is less clear compared with other indicators.

One study examined whether employment was associated with uncontrolled asthma based on having two or more exacerbations in the previous year.[61] Based in rural Appalachia, Kentucky, this cross-sectional study measured employment using employment status. While employment appeared to impact whether an individual reported having asthma, it was not a statistically significant predictor of uncontrolled asthma after controlling for age, sex, perceived financial status, and accommodation (OR 0.69 [0.23–2.05]). Given the broad categorisation, where unemployment was in the same group as part-time employment, full-time students and retired, it is hard to determine the role of unemployment in predicting exacerbation-based uncontrolled asthma.

Discussion

Overall, we found a clear association between lower income and exacerbations in both children and adults. We were unable to assess statistically the association between unemployment and asthma outcomes; instead, we narratively synthesised the role of unemployment. Despite the limited evidence, narratively, we found that unemployment was associated with ED visits. However, the association between unemployment and uncontrolled asthma based on exacerbations was unclear.

The narrative synthesis indicated a stress-mediated indirect association between unemployment and asthma-related healthcare utilisation. This suggests that the psychological burden of unemployment may exacerbate asthma symptoms and hinder effective self-management. Evidence indicates that sustained physiological stress intensifies the immune response, such as hypothalamic-pituitary-adrenocortical activation.[68–71] This leads to a decrease in β_2 adrenergic and glucocorticoid receptors, which reduces the responsiveness to asthma medication and, in turn, increases the risk of exacerbation.[70,72] Employment provides financial stability and benefits, such as employer health insurance and sick leave, that can facilitate disease management.[73] Without these privileges, the unemployed are likely to delay or forgo health care-seeking behaviours and present themselves in ED with more severe outcomes.[7,74] However, this is limited to adults as unemployment is not a strong predictor of paediatric asthma outcomes compared with other SES indicators.

The wider literature on income and asthma corroborates our findings. Low-income households are strongly associated with limited access to essential resources and amenities, including nutritious food and healthcare services, that increase their risk of asthma exacerbations.[75–77] They are more likely to live in subsidised or social housing, which is often too small and of poor quality, beset with overcrowding and disproportionate levels of indoor and outdoor pollution.[78] Maintaining and repairing these homes is expensive, thus increasing their exposure to damp, mould, pests, and second-hand smoke. Unsurprisingly, subsidised housing is associated with experiencing asthma attacks in the previous year.[79] Children are at greater risk due to their limited immune response to microbial exposure and more so in urban areas whose greater residential density increases the concentration of these agents.[80,81] Also, children with asthma living in these settings are at greater odds of an ED visit than children residing with homeowning parents.[82] As a result, asthma patients on low incomes are denied the structural means to ameliorate their condition. They may also struggle to afford medication.

Pooled estimates from six high-income countries indicated that lower household income in early childhood was associated with the risk of developing poorer asthma-related outcomes.[83] A study investigating the association between socioeconomic position (SEP), an indicator of SES,[84,85] and asthma in a historical cohort of male university students found an association between low SEP in early life and asthma.[86] However, there is no association between adult SEP and adult-onset asthma. Using a different measure of SES, such as IMD, would possibly yield different results. Notwithstanding the smaller magnitude, our findings align with previous systematic reviews and meta-analyses on socioeconomic status and asthma outcomes. Lower SEP was associated with higher rates of asthma-related ED attendances.[15] A systematic review identified 31 studies where the lowest-income group had between 1.5 and 5 times the hospitalisation rate for asthma compared with the highest-income group.[87] Unlike these reviews, this review conducted a subgroup analysis of children and adults to explore heterogeneity by population. While there was a clear association in both children and adults, there was no evidence of a significant difference in the magnitudes of effect.

Other factors, such as medication use and adherence (or lack thereof), may relate directly to poor asthma outcomes. There is a tendency to overuse short-acting β-2 agonists (SABA), which do not address inflammation but only offer immediate symptom relief. High SABA use is found to be associated with poorer clinical outcomes, including exacerbations,[88,89] hospitalisations,[90,91] and mortality.[92,93] Evidence illustrates a dose–response relationship between SABA inhaler use and exacerbation risk, with even mild asthma patients experiencing exacerbations, whose risk was further elevated with high SABA use.[94–98] Many studies have demonstrated the benefits of high adherence to asthma controller therapy in reducing the risk of exacerbation and death.[99–102] However, the effects of inhaled corticosteroids (ICS) adherence on mainly exacerbations are less clear. Studies identified a non-linear, U-shaped association between ICS adherence and exacerbations.[103–106] In other words, better adherence does not always mean better asthma outcomes. Analysis from England observed that ICS adherence was better in Clinical Commissioning Group regions with greater socioeconomic deprivation, with these areas also having worse asthma outcomes which may relate to SES factors specifically.[107] Also, the relationship between socioeconomic deprivation and asthma outcomes did not appear to be primarily mediated by poor adherence to ICS. SABA over-reliance and ICS adherence could be driven by suboptimal patient knowledge about the difference between maintenance and reliever medication, the patient's need for immediate symptom relief, concerns about the side effects of steroids, and poor communication between patients and physicians as well as different prescribing behaviours by physicians due to perverse incentives.[108]

The main strength of this review was summarising the evidence on the effect of income and, though limited, employment, the most weighted IMD domains, on asthma outcomes. Both the meta-analysis and narrative synthesis offer a better understanding of the association between these domains and asthma outcomes. The studies included in this review were published between 2010 and 2025, thus reflecting more recent evidence than in previous reviews.[14,15]

However, there are limitations to this review. 60% of the included studies were from the US (18 studies) compared to seven from the UK, three from Canada

and only two from the other European countries (Denmark and France). There are likely to be different constructs to assess SES. On the one hand, some North American studies used state[49,65] or federal[40,55,62] income thresholds. Other studies included stress,[40] health insurance coverage,[47] and race/ethnicity.[67] Depending on the population, studies also looked at bespoke deprivation indices, such as the Child Opportunity Index (COI),[63,66] Distressed Communities Index,[60] and Neighborhood Deprivation Index.[64] On the other hand, UK-based studies predominantly used IMD.[50–53,57–59] Not only does this affect the generalisability of findings to other Western countries but also many non-Western countries where there are greater inequalities. Only studies published in English were included for practical reasons, potentially introducing a language bias. We were unable to search in other language databases and, therefore, may have missed potentially useful studies.

Moreover, there are some limitations to the evidence. Due to the lack of studies available to conduct a meta-analysis, we narratively synthesised the role of unemployment on asthma outcomes. However, this was limited to only three studies. Likewise, there were insufficient studies to quantify the association between income and hospital admissions and mortality. The studies included in the meta-analysis predominantly defined exacerbations by ED visits, hospitalisations and/or OCS. The exacerbation rate ranges from <1% to 29% in the included studies, or <10 exacerbations per 1000 patients vs. 290 exacerbations per 1000 patients.[46,55] Depending on the baseline exacerbation rate, the pooled OR estimate of 1.25 could pose an uneven burden on EDs. In practice, this could translate from as little as 500 more events per 100,000 patients per year (1–2 more events per day) to as high as 7200 per 100,000 patients per year (approximately 20 more per day), which could overwhelm EDs. Considering these findings mainly reflect severe exacerbations, the results are likely skewed, and the burden on secondary care will likely be overestimated. Nonetheless, more evidence is required to assess the associations between income and asthma outcomes beyond severe exacerbations and between unemployment and asthma outcomes.

The subgroup analysis showed no significant difference, with the variation in the definition of exacerbation explained mainly by the heterogeneity in adults. Further studies need to address the heterogeneity in adults. Also, only one moderator was examined as other possible effect-modifying study-related factors were subject to reporting differences in sex (by intervention or exposure), age (mean, median and frequency) and ethnic groups. Therefore, we cannot rule out the impact of these moderators on the associations.

Our findings have research, clinical, and policy implications. Since all studies investigated the association at a high-income/employment level, there is scope to disentangle the mechanisms underpinning these inequalities in disadvantaged populations. Not only does this indicate a persistent issue that has yet to be resolved, but it is also multifaceted. Employment and income represent material disadvantages, i.e., limited wealth and access to goods and conveniences (Fig. 4).[109] As living a healthy life is prohibitively expensive, the most deprived are more likely to live in substandard housing and have poor nutrition. These adverse exposures may work synergistically against the most deprived groups, who are excessively exposed to indoor and outdoor air pollution while lacking the protective effects of a healthy diet to stimulate an immune response.[110,111] This can have pathobiological effects on people born into deprivation, who have worse airways or who are already born in a pro-inflammatory state.[112,113] Evidence indicates that the incidence of developing asthma is statistically significantly increased when children are exposed early in life.[114] The most deprived children were reported to have higher levels of airway inflammation and worse lung function.[115] Meanwhile, these groups are affected by The Inverse Care Law: the "availability of good medical care tends to vary inversely with the need for it in the population served".[116] Given their precarious working arrangement, such as zero-hour contracts, leaving work to access appointments is expensive. Not only is there the risk of loss of income and employment but also the risk of long-term poorer health outcomes from restricted access to healthcare.[112] These are likely to have knock-on effects on education, health, housing, and the wider environment.[117] Improving the material disadvantages can improve the "structural (e.g., systemic racism); social (e.g., socioeconomic status [SES]); biological (e.g., genetics);

Fig. 4: **A matrix illustrating the synergistic effects of material disadvantages on poor asthma outcomes.**

and behavioural (e.g., smoking) factors" driving the widespread disparities.[118] Addressing the material disadvantages is paramount to improving widespread disparities, which will require researchers to explore at the domain level rather than the aggregate level.

When developing interventions, clinicians need to understand how underlying mechanisms manifest in the clinical pathway and affect outcomes. Here, clinicians should consider the co-existing drivers for inequality that may have synergistic effects, where the Inverse Care Law may manifest in clinical pathways, and how the pathobiology of poverty might impact clinical outcomes (and what can be done to address this). This can support efforts to advance knowledge of the interactions between environmental, genetic and immunological factors, as well as policies highlighting the need for equity in reducing health disparities.[13]

Policymakers could reduce the effects of income and unemployment on asthma outcomes by improving housing conditions, especially for at-risk populations like children, and unemployment-induced stress. Despite the housing shortages and the need to build new homes, houses should be free from indoor and outdoor pollution. Offering a tailored package of housing improvements, such as remediation, to low-income households should include incentives such as shopping vouchers and credit to utility bills.[119] Amid welfare reform, including changes to unemployment benefits, policymakers should provide further psychological resources and career support to facilitate government efforts to 'get Britain working again'. Policies should embed mental health support in employment programmes, offering regular contact and health checks (including asthma reviews) until the individual finds a job.[120] Should these policies be implemented successfully, more people will be working and earning an income. Living in a secure and stable environment means less disposable income is spent on repairs and maintenance. Addressing these widespread disparities will improve asthma outcomes and reduce overall inequalities in the long term.

In conclusion, income is an important indicator of SES that is associated with severe asthma exacerbations in children and adults. In contrast, we were unable to determine the role of unemployment in asthma outcomes. More evidence is required to assess the associations between income and asthma outcomes beyond severe exacerbations and unemployment and asthma outcomes more generally. Domain-level studies can help fully understand the mechanisms underlying these associations. Studies also need to investigate further the heterogeneity in adults. Interventions addressing the material disadvantages can inform and better target policies, such as improved housing conditions and unemployed-related stress. These will help researchers, clinicians, and policymakers get closer to improving asthma outcomes and reducing health inequalities.

Contributors

ZG, AS, IS, GAD, HW, CK and JKQ conceived the study design. ZG, IDK, EM, AMA and AT screened the studies for inclusion and extracted the data. ZG assessed the studies for risk of bias, conducted the meta-analysis and drafted the manuscript. HW and CK provided methodological and statistical support. AS, IS, GAD, CK, HW and JKQ edited and reviewed the manuscript. HW, CK and JKQ provided supervision. ZG, HW, CK and JKQ accessed and verified the underlying data. All authors had full access to all the data in the study and had final responsibility for the decision to submit for publication.

Data sharing statement

Requests for data can be made to the corresponding author.

Declaration of interests

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Appendix A. Supplementary data

Supplementary data related to this article can be found at https://doi.org/10.1016/j.lanepe.2025.101367.

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83rd OREGON LEGISLATIVE ASSEMBLY--2025 Regular Session

Enrolled
House Bill 3179

Sponsored by Representative SOSA, Senator TAYLOR, Representative MARSH, Senator SOLLMAN; Representatives ANDERSEN, CHAICHI, CHOTZEN, DOBSON, FRAGALA, GAMBA, GOMBERG, GRAYBER, HARTMAN, HUDSON, KROPF, LEVY E, LIVELY, MCDONALD, MUNOZ, NERON, NGUYEN D, NGUYEN H, RIEKE SMITH, WALTERS, Senators GOLDEN, PATTERSON, PHAM K (at the request of Citizens' Utility Board) (Presession filed.)

CHAPTER .....

AN ACT

Relating to public utilities; creating new provisions; amending ORS 757.210, 757.215, 757.457 and 757.461; and declaring an emergency.

Be It Enacted by the People of the State of Oregon:

ELECTRIC AND NATURAL GAS UTILITY RATES

SECTION 1. Section 2 of this 2025 Act is added to and made a part of ORS 757.210 to 757.220.

SECTION 2. (1) As used in this section, "electric or natural gas company" means any entity that is a public utility that is engaged in the business of distributing electricity or natural gas to retail customers in this state.

(2) In determining whether an electric or natural gas company's proposed residential rate or schedule of rates to be established or increased or changed is fair, just and reasonable, the Public Utility Commission shall balance the interests of the utility investor and the consumer by considering the cumulative economic impact of the proposed rate or schedule of rates on the electric or natural gas company's residential ratepayers.

(3) An electric or natural gas company shall conduct and include with its filing an analysis of the cumulative economic impact of a proposed rate or schedule of rates on the electric or natural gas company's residential ratepayers if the electric or natural gas company's proposed residential rate or schedule of rates will result in an increase of residential rates and the electric or natural gas company's return on equity is subject to review and modification. The analysis must take into consideration the following:

(a) For each classification of service of the electric or natural gas company affected by the proposed rate or schedule of rates and, if applicable, distinguished by ratepayers who reside in single-family housing and ratepayers who reside in multifamily housing:

(A) Ratepayers' average monthly utility bill for the 18 months ending on the date before the date the proposed rate or schedule of rates is to take effect;

(B) The approximate range of utility bills from November 1 to March 31 for the prior two years for residential ratepayers who use the utility service for space heating; and

(C) The estimated dollar amount and percentage increase in ratepayers' utility bills;

(b) The average cost of living and cost of fuel and utilities for the region, state and, where available, service territory of the electric or natural gas company, as determined by the commission using the Consumer Price Index for All Urban Consumers, West Region (All Items), as most recently published by the Bureau of Labor Statistics of the United States Department of Labor, and any other macroeconomic data as determined by the commission;

(c) The electric or natural gas company's data on residential service disconnection for nonpayment, including:

(A) The number of ratepayers the electric or natural gas company disconnected for nonpayment in the previous 12 months;

(B) The number of ratepayers receiving energy assistance, including any government assistance, utility bill discount or utility arrearage program, that the electric or natural gas company disconnected for nonpayment in the previous 12 months;

(C) The number of ratepayers who have a medical certificate filed with the electric or natural gas company; and

(D) Data related to customers who are enrolled in the electric or natural gas company's energy assistance programs, including disconnection moratorium programs;

(d) The electric or natural gas company's data on overdue balances, as determined by the commission, such as:

(A) The number of ratepayers who have an overdue balance;

(B) The average amount of the overdue balances; or

(C) The total amount of overdue balances owed to the electric or natural gas company;

(e) Data on the cost of energy for commercial and industrial customers relative to the cost of energy for commercial and industrial customers in other states in the region together with historical trends; and

(f) Any other relevant data, as determined by the commission, such as indicators of financial hardship, residential customer energy burden or affordability of utility bills.

(4) The commission may contract or coordinate with other state agencies, energy assistance providers or the nongovernmental entity that administers funds collected pursuant to ORS 757.054, through natural gas tariffs or through public purpose charges pursuant to ORS 757.612, to collect data necessary to carry out this section.

(5) The commission may establish rules to carry out this section, including rules that require electric and natural gas companies to gather information or data necessary to carry out this section.

SECTION 3. ORS 757.210 is amended to read:

757.210. (1)(a) Whenever any public utility files with the Public Utility Commission any rate or schedule of rates stating or establishing a new rate or schedule of rates or increasing an existing rate or schedule of rates, the commission may, either upon written complaint or upon the commission's own initiative, after reasonable notice, conduct a hearing to determine whether the rate or schedule is fair, just and reasonable. The commission shall conduct the hearing upon written complaint filed by the utility, its customer or customers, or any other proper party within 60 days of the utility's filing; provided that no hearing need be held if the particular rate change is the result of an automatic adjustment clause. At the hearing the utility shall bear the burden of showing that the rate or schedule of rates proposed to be established or increased or changed is fair, just and reasonable. The commission may not authorize a rate or schedule of rates that is not fair, just and reasonable.

(b) As used in this subsection, "automatic adjustment clause" means a provision of a rate schedule that provides for rate increases or decreases or both, without prior hearing, reflecting increases or decreases or both in costs incurred, taxes paid to units of government or revenues earned by a utility and that is subject to review by the commission at least once every two years.

(2)(a) Subsection (1) of this section does not apply to rate changes under an approved alternative form of regulation plan, including a resource rate plan under ORS 757.212.

(b) Any alternative form of regulation plan shall include provisions to ensure that the plan operates in the interests of utility customers and the public generally and results in rates that are just and reasonable and may include provisions establishing a reasonable range for rate of return on investment. In approving a plan, the commission shall, at a minimum, consider whether the plan:

(A) Promotes increased efficiencies and cost control;

(B) Is consistent with least-cost resources acquisition policies;

(C) Yields rates that are consistent with those that would be obtained following application of ORS 757.269;

(D) Is consistent with maintenance of safe, adequate and reliable service; and

(E) Is beneficial to utility customers generally, for example, by minimizing utility rates.

(c) As used in this subsection, "alternative form of regulation plan" means a plan adopted by the commission upon petition by a public utility, after notice and an opportunity for a hearing, that sets rates and revenues and a method for changes in rates and revenues using alternatives to cost-of-service rate regulation.

(d) Prior to implementing a rate change under an alternative form of regulation plan, the utility shall present a report that demonstrates the calculation of any proposed rate change at a public meeting of the commission.

(3) Except as provided in ORS 757.212, the commission, at any time, may order a utility to appear and establish that any, or all, of its rates in a plan authorized under subsection (2) of this section are in conformity with the plan and are just and reasonable. Except as provided in ORS 757.212, such rates, and the alternative form of regulation plan under which the rates are set, also shall be subject to complaint under ORS 756.500.

(4) Periodically, but not less often than every two years after the implementation of a plan referred to in subsection (2) of this section, the commission shall submit a report to the Legislative Assembly that shows the impact of the plan on rates paid by utility customers.

(5) The commission and staff may consult at any time with, and provide technical assistance to, utilities, their customers, and other interested parties on matters relevant to utility rates and charges. If a hearing is held with respect to a rate change, the commission's decisions shall be based on the record made at the hearing.

(6) The commission may adjust rates to mitigate an increase in residential customer rates if the increase is of such magnitude that, if applied at the higher rate or all at one time, the increase would affect the ability of residential customers to maintain adequate utility service. In considering whether to adjust rates under this subsection, the commission:

(a) Must determine whether the proposed adjusted rates are fair, just and reasonable;

(b) May not adjust rates in a manner that results in rates that are not fair, just and reasonable; and

(c) Shall consider and may approve deferred accounting for future cost recovery from customers for those amounts that are subject to rate mitigation.

(7) Any increase in residential rates may not take effect from November 1 to March 31.

SECTION 4. (1) Notwithstanding any other provisions of law, if an electric or natural gas company's proposal to increase rates under ORS 757.210 subjects the electric or natural gas company's return on equity to review or modification by the Public Utility Commission, the rate increase may not take effect within 18 months from the effective date of the electric or natural gas company's last rate increase under ORS 757.210 that subjected the electric or natural gas company's return on equity to review or modification by the commission.

(2) Notwithstanding ORS 757.259, the commission shall consider and may approve deferred accounting for future cost recovery from ratepayers under an electric or natural gas company's requested rate revision, if the rate revision subjects the electric or natural gas company's return on equity to review or modification.

(3) As used in this section, "electric or natural gas company" means a public utility, as defined in ORS 757.005, that is engaged in the business of distributing electricity or natural gas to retail customers in this state.

SECTION 5. Section 4 of this 2025 Act is repealed on the earlier of:

(1) January 2, 2027.

(2) The date the Public Utility Commission adopts permanent rules to implement section 7 of this 2025 Act.

SECTION 6. Section 7 of this 2025 Act is added to and made a part of ORS chapter 757.

SECTION 7. (1) As used in this section, "electric or natural gas company" means any entity that is a public utility that is engaged in the business of distributing electricity or natural gas to retail customers in this state.

(2)(a) The Public Utility Commission shall establish rules requiring an electric or natural gas company to establish a multiyear rate plan for rate revisions that subject an electric or natural gas company's return on equity to review or modification.

(b) The rules must:

(A) Include procedural and content requirements for a multiyear rate plan.

(B) Require an electric or natural gas company to file a multiyear rate plan on a regular interval that is no less than three and no more than seven years long.

(C) Establish a limit on the number of electric or natural gas companies that are allowed to request a rate increase in any given year.

(c) The rules may:

(A) Provide for incentives for efficient utility operations.

(B) Authorize refunds to customers under certain circumstances.

(C) Allow an electric or natural gas company, or third party, to request an exception to a requirement established by rule under this section on a showing of good cause.

(3) The provisions of this section do not allow for cost recovery that is not permitted under ORS 757.355.

SECTION 8. ORS 757.215 is amended to read:

757.215. (1) The Public Utility Commission may, pending such investigation and determination, order the suspension of the rate or schedule of rates for a period of up to [*nine*] **10** months beyond the time when such rate or schedule would otherwise go into effect.

(2) This section does not prevent the commission and the utility from entering into a written stipulation at any time extending any period of suspension.

(3) After full hearing, whether completed before or after such rate or schedule has gone into effect, the commission may make such order in reference thereto as would be proper in a proceeding initiated after such rate or schedule has become effective.

(4) If the commission is required to or determines to conduct a hearing on a rate or schedule of rates filed pursuant to ORS 757.210, but does not order a suspension thereof, any increased revenue collected by the utility as a result of such rate or rate schedule becoming effective shall be received subject to being refunded. If the rate or rate schedule thereafter approved by the commission is for a lesser increase or for no increase, the utility shall refund the amount of revenues received that exceeds the amount approved as nearly as possible to the customers from whom such excess revenues were collected, by a credit against future bills or otherwise, in such manner as the commission orders.

(5) The commission may in a suspension order authorize an interim rate or rate schedule under which the utility's revenues will be increased by an amount deemed reasonable by the commission, not exceeding the amount requested by the utility. Any such interim increase for a public utility as defined in ORS 757.005 that produces, transmits, delivers or furnishes heat, light or power shall be effected by rates designed to increase the utility's revenues without materially changing the revenue relationships among customer classes or between the revenues derived from demand charges and from energy charges. An interim rate or rate schedule shall remain in effect until terminated by the commission. Upon completion of the hearing and decision, the commission shall order the utility to refund that portion of the increase in the interim rate or schedule that the commission finds is not justified. Any refund of an interim increase under this subsection shall be based upon an analysis of the utility's earnings for a period reasonably representative of the period during which the in-

terim increase was in effect. Refunds shall be made as nearly as possible to the customers against whom the interim rates were charged, by credits against future bills or in such other manner as the commission orders.

(6) Refunds ordered by the commission under subsection (4) or (5) of this section shall include interest on the amount determined to be subject to refund from the date such interim rate or rate schedules took effect.

FINANCING OF CERTAIN RATE RECOVERY EXPENDITURES

SECTION 9. ORS 757.457 is amended to read:

757.457. As used in this section and ORS 757.459, 757.461 and 757.463:

(1) "Assignee" means a person, and any subsequent assignee, to which a public utility assigns, sells or transfers all or part of the public utility's interest in or right to rate recovery assets, except as security.

(2) "Bond" includes bonds, notes, certificates of beneficial interests in a trust or other evidence of indebtedness.

(3) "Bondholder" means a holder or owner of a rate recovery bond.

(4) "Finance subsidiary" means an assignee at the time rate recovery bonds are issued:

(a)(A) That is beneficially owned, directly or indirectly, by a public utility; or

(B) In the case of a trust, for which a public utility or subsidiary of the public utility is the grantor; or

(b) That is unaffiliated with a public utility and acquires bondable rate recovery assets from a public utility in a transaction or under an agreement that is approved by the Public Utility Commission.

(5) "Financing costs" includes the following costs related to rate recovery bonds, whether incurred and paid upon issuance or over the life of rate recovery bonds:

(a) The costs of issuing, serving, managing, repaying or refinancing rate recovery bonds, including any fees, expenses or charges incurred and the costs of any activities performed in connection with the rate recovery bonds, including:

(A) Information technology programming;

(B) Obtaining a financing order;

(C) Serving, accounting or auditing;

(D) Services related to trustees;

(E) Legal services;

(F) Consulting;

(G) Services related to financial and structuring advisors;

(H) Administration;

(I) Placement and underwriting;

(J) Services related to independent directors and managers;

(K) Services related to rating agencies;

(L) Stock exchange listing and compliance;

(M) Securities registration and filing; and

(N) Services necessary to ensure a timely payment of rate recovery bonds or other amounts or charges payable in connection with rate recovery bonds;

(b) Principal, interest and acquisition, defeasance and redemption premiums payable on rate recovery bonds;

(c) Payments required under an ancillary agreement and any amounts required to fund or replenish a reserve or account established under the terms of an indenture, ancillary agreement or financing document related to rate recovery bonds;

(d) Applicable federal, state and local taxes, franchise fees, license fees, gross receipts or other taxes or charges, whether paid, payable or accrued; and

(e) The Public Utility Commission's costs in performing the commission's duties related to rate recovery bonds that are recoverable by the commission under ORS 756.310.

(6) "Financing order" means an order issued by the Public Utility Commission that authorizes one or more the following:

(a) The recovery of rate recovery expenditures and financing costs;

(b) The creation of rate recovery assets;

(c) The issuance of rate recovery bonds;

(d) The imposition, collection and periodic adjustment of rate recovery charges; or

(e) The sale, assignment or transfer of rate recovery assets to an assignee.

(7) "Financing party" includes:

(a) Bondholders, trustees, agents and secured parties related to rate recovery bonds;

(b) A person acting for the benefit of bondholders, trustees, agents or secured parties; and

(c) A party to rate recovery bond documents or an ancillary agreement.

(8) "Public utility customer" means:

(a) For an electric utility, a retail electricity consumer, as defined in ORS 757.600.

(b) For a natural gas utility, the end use consumer served by the natural gas utility, including those served by the natural gas utility under ORS 757.516, regardless of whether the end use consumer purchases natural gas from the natural gas utility.

(9) "Rate recovery asset" means a right to recover from customers rate recovery expenditures and associated costs and expenses approved in a financing order, including the right to:

(a) Impose, charge, bill, collect, receive, hold and apply rate recovery charges authorized under a financing order or obtain, to the extent authorized, periodic adjustments of rate recovery charges; and

(b) All claims, accounts, revenues, payments, collections, moneys or proceeds arising from the rights and interest specified in a financing order, regardless of whether the claims, accounts, revenues, payments, collections, moneys or proceeds arising from the rights and interest specified in the financing order are commingled with other claims, accounts, revenues, payments, collections, moneys or proceeds.

(10) "Rate recovery charge" means charges to public utility customers authorized by the Public Utility Commission to recover rate recovery expenditures and financing costs and to be used to pay, repay or refinance rate recovery bonds.

(11) "Rate recovery expenditures" means costs and expenses incurred or to be incurred [*through the date of issuance of a financing order*] by a public utility associated with:

(a) An event that is the subject of a federal or state declaration of a state of emergency, such as severe weather, catastrophic wildfire, pandemic or other event that causes or threatens to cause widespread loss of life, injury to person or property, human suffering or financial loss, except those costs and expenses that are or are associated with criminal or civil fines or penalties or judgments from a civil action based on negligence related to the event.

(b) An energy conservation program that provides loans and cash payments to public utility customers for the installation of energy conservation measures funded by the public utility including, but not limited to, the costs or expenditures for specific acquisition program development, promotion and labor costs and associated general supervision, rents, leases and overheads.

(c) A capital investment:

(A) That by itself will cause residential rates to rise by more than five percent; and

(B) When combined with other expected investments or expenses, has the potential to significantly impact the affordability of residential rates.

(d) Retiring a generation asset, including undepreciated investments, decommissioning and restoring a facility site, related capital and operating costs, accrued carrying charges and deferred costs.

(e) Planned or past remediation of a contaminated site or environmental remediation activities and related partial or final payments or settlements.

(f) An event in which the availability of electricity or natural gas within a regional energy market is significantly constrained.

(12) "Secured party" means a financing party that has been granted a security interest in rate recovery assets.

SECTION 10. ORS 757.461 is amended to read:

757.461. (1)(a) A public utility may apply to the Public Utility Commission for a financing order designating all or part of rate recovery expenditures as bondable rate recovery expenditures, for the purpose of financing or refinancing the designated expenditures under ORS 757.415 (1)(f).

(b) After notice and an opportunity for a hearing, the commission may approve an application if the commission finds that:

(A) The rate recovery expenditures included in the application are reasonable and prudent;

(B) Financing or refinancing the rate recovery expenditures through the issuance of rate recovery bonds is likely to be more favorable to public utility customers for the recovery of rate recovery expenditures as compared to other methods; and

(C) Bonds, notes, certificates of beneficial interests in a trust and other evidences of indebtedness or ownership issued pursuant to the approval are reasonably likely to receive a determination of, at a minimum, investment grade by credit rating agencies.

(c) The commission shall issue an order within 180 days of an application approving or denying the application. If the commission approves the application, the commission shall issue a financing order.

(2)(a) A financing order issued under this section shall specify the highest amount of rate recovery expenditures that qualify as bondable rate recovery expenditures.

(b) In specifying the amount for rate recovery expenditures associated with an event described in ORS 757.457 (11)(a), net of appropriate adjustments as determined by the commission to be reasonable, the commission may include, but is not limited to including, the following rate recovery expenditures:

(A) Capital and operating costs incurred or to be incurred as a result of the event;

(B) Lost revenue associated with the event;

(C) Costs and expenses that may be recovered at a later time from third parties or insurers and returned to public utility customers through a separate rate proceeding consistent with cost causation and rate design principles and statutory or regulatory requirements; and

(D) Carrying costs or charges.

(3) A financing order issued under this section must include the following provisions:

(a) Confirmation of the existence of recoverable rate recovery expenditures and authorization to recover rate recovery expenditures and associated financing costs, including the maximum principal amount of bondable rate recovery expenditures and financing costs that may be recovered through securitization;

(b) Authorization for the creation of rate recovery assets and imposition of rate recovery charges that allow for the recovery of rate recovery expenditures, as determined by the commission, and associated financing costs;

(c) A requirement that the rate recovery charges authorized by the financing order are ongoing and may not be avoided by a public utility customer, as described under subsection (4) of this section, until all principal, interest, premium and other amounts due on the rate recovery bonds and financing costs have been paid in full;

(d) A methodology for:

(A) Allocating rate recovery charges between the different classes of public utility customers, which may include not allocating rate recovery charges to one or more classes of public utility customers, that is consistent with cost causation and rate design principles and statutory or regulatory requirements; and

(B) Adjusting rate recovery charges as necessary to ensure timely payment on, and payment in full of, the rate recovery bonds and associated financing costs or in response to changes to applicable customers, service territories or collection rates;

(e) Authorization for the public utility to issue one or more series of rate recovery bonds with flexibility for the public utility to establish the terms and conditions of the rate recovery bonds, including repayment schedules, initial interest rates and initial financing costs;

(f) Authorization to assign rate recovery assets to a financing subsidiary and grant security interests in the rate recovery assets to secured parties without limiting the rights of subsequent assignees;

(g) Authorization for the bond documentation and ancillary documents related to the rate recovery bonds, including servicing arrangements for the rate recovery charges, without requiring the authorization to be on the final forms of the documents;

(h) Authorization **for the reasonable opportunity** for the public utility to earn a return, at the cost of capital authorized in the public utility's most recent general rate case prior to the date of the financing order, on any moneys advanced by the public utility to fund advances, reserves or capital accounts established under the terms of any indenture, ancillary agreement or financing documents related to the rate recovery bonds;

(i) A finding that the proposed issuance of rate recovery bonds and the imposition of rate recovery charges is expected to provide the lowest possible reasonable and prudent cost on a net present value basis to public utility customers for recovery of the rate recovery expenditures as compared to **the public utility's weighted average cost of capital or** other methods of financing and recovery;

(j) A date, not earlier than one year from the date that the financing order becomes final, on which the authority to issue rate recovery bonds granted in the financing order expires;

(k) A requirement that the public utility notify the commission if the public utility recovers costs and expenses from a third party or insurer; and

(L) Any other conditions that the commission finds appropriate and that are consistent with this section.

(4) Rate recovery charges authorized by a financing order shall be collected through the rates or charges paid by, and may not be avoided by, the public utility customers located within the public utility's allocated service territory, as the territory existed on the date of the financing order or, if the financing order provides, as such service territory may be expanded, even if:

(a) The public utility customer receives electricity or natural gas, electricity or natural gas services or ancillary services from a successor or assignee of the public utility;

(b) The public utility customer elects to receive electricity or natural gas, electricity or natural gas services or ancillary services from another public utility, utility provider or service provider in the service territory; or

(c) After the date of issuance of the financing order, the public utility customer changes customer class.

(5)(a) Rate recovery assets, including rate recovery charges, and the rights of public utilities, assignees, bondholders and financing parties, established by a financing order issued under this section, are irrevocable and unchangeable, except as provided in the financing order, until all principal, interest, premium, interest and amounts due on the rate recovery bonds and financing costs are paid in full.

(b) Until all principal, interest, premium, interest and amounts due on the rate recovery bonds and financing costs are paid in full, the commission, except as provided in the financing order, the State of Oregon and a public body, as defined in ORS 174.109, may not:

(A) Revalue the rate recovery expenditures or financing costs for ratemaking purposes;

(B) Determine that the rates or revenues authorized under the financing order are unjust or unreasonable;

(C) Reduce, alter or impair the rate recovery assets, rate recovery charges or the collection of the rate recovery charges, or rate recovery bonds or the security for the rate recovery bonds;

(D) Rescind, suspend, amend or impair the financing order; or

(E) When setting other rates or charges for the public utility or taking other actions pursuant to the commission's authority, consider the rate recovery bonds as debt of the public utility, the rate

recovery assets to be revenue for the public utility or the rate recovery expenditures to be costs of the public utility.

(6) If the commission determines that financing certain rate recovery expenditures through the issuance of rate recovery bonds would potentially result in benefits to public utility customers, the commission may identify those rate recovery expenditures and direct a public utility to investigate and report to the commission on the costs, benefits and risks of financing those rate recovery expenditures. The report may include an analysis of the following:

(a) Any future need for the use of rate recovery bonds;

(b) The ability of the public utility to raise capital;

(c) Intergenerational equity;

(d) The percentage of customers' utility bills that are currently dedicated to rate recovery bond payments; and

(e) The percentage of customers' utility bills that would need to be dedicated to rate recovery bond payments to finance the rate recovery expenditures analyzed in the report.

[*(6)*] **(7)** The commission may not require a public utility to:

(a) Apply to the commission for a financing order designating all or part of rate recovery expenditures as bondable rate recovery expenditures; or

(b) Finance or refinance rate recovery expenditures that the commission has designated as bondable rate recovery expenditures.

[*(7)*] **(8)** Jurisdiction for review of a financing order issued under this section shall be as provided for orders in contested cases pursuant to ORS 183.482, except that a petition for rehearing or reconsideration is not allowed. If a petition is not filed with the Court of Appeals within 60 days following the date of issuance of a financing order, the order becomes a final and irrevocable action of the commission and the State of Oregon and is not subject to administrative or judicial challenge.

(9) In determining whether an event as described under ORS 757.457 (11)(f) qualifies as a rate recovery expenditure, the commission shall take into consideration the following factors:

(a) The cost and availability of wholesale power or natural gas during the event;

(b) The applicability of any regional reliability assistance programs; and

(c) Any issuance of a declaration related to energy reliability by a regional balancing authority.

REPORTS BY PUBLIC UTILITIES

SECTION 11. Sections 12 and 13 of this 2025 Act are added to and made a part of ORS chapter 757.

SECTION 12. (1) As used in this section and section 13 of this 2025 Act, "electric or natural gas company" means any entity that is a public utility that is engaged in the business of distributing electricity or natural gas to retail customers in this state.

(2) Each calendar year, an electric or natural gas company shall provide to the Public Utility Commission, and make publicly available on the electric or natural gas company's website, a visual representation of the cost categories that are included in the electric or natural gas company's residential customer rates and the percentage amount of the residential customer rates for each cost category.

(3) The commission shall by rule establish the cost categories. Cost categories must include the following:

(a) Transmission services infrastructure;

(b) Distribution services infrastructure;

(c) Power costs;

(d) Wildfire mitigation;

(e) Catastrophic events and emergencies;

(f) Insurance, including self-insurance; and

(g) Any other expenses, as determined by the commission, that an electric or natural gas company seeks to recover through residential customer rates.

SECTION 13. (1) The Public Utility Commission shall require each electric and natural gas company to, at least annually, file with the commission, and make publicly available, a report on any rate adjustments that the electric or natural gas company expects within the next 12 months.

(2) A report under this section must:

(a) Identify all rate adjustment requests that an electric or natural gas company has filed or reasonably knows or anticipates to file;

(b) Identify other requests or applications that could result in a rate adjustment;

(c) Provide estimates on the amounts of expected rate adjustments, if the amounts in expected rate adjustments are not known with certainty; and

(d) For each rate adjustment request that an electric or natural company has filed or reasonably knows or anticipates to file:

(A) Specify the date the electric or natural gas company filed or anticipates filing the request with the commission;

(B) Specify the date the electric or natural gas company requests or anticipates requesting that the rate adjustment take effect;

(C) Provide the overall estimated rate impact, expressed in dollar and percentage amounts, that would result from the rate adjustment if approved;

(D) Provide the cumulative rate impact of a rate adjustment in the aggregate with all other rate adjustments that take effect between the date of the report and the date the rate adjustment takes effect; and

(E) Identify the classification of service or customer that may be affected by a rate adjustment and forecast how the rate adjustment may affect rates for the other customer classes of the electric or natural gas company.

(3) An electric or natural gas company is not required under this section to make publicly available any information or material that is subject to confidentiality under the rules of the commission.

(4) The commission shall adopt rules to carry out the provisions of this section. The rules must provide for procedures for an electric or natural gas company to protect the confidentiality of the information described under subsection (2) of this section through the use of a protective order, subject to review and approval by the commission.

APPLICABILITY

SECTION 14. (1) Except as provided in subsection (2) of this section, sections 2 and 4 of this 2025 Act and the amendments to ORS 757.210 and 757.215 by sections 3 and 8 of this 2025 Act apply to proceedings before the Public Utility Commission that commence on or after the effective date of this 2025 Act.

(2) ORS 757.210 (7) applies to increases in residential rates that are approved on or after the effective date of this 2025 Act.

EXPENDITURES LIMIT

SECTION 15. Notwithstanding any other law limiting expenditures, the limitation on expenditures established by section 1 (1), chapter ___, Oregon Laws 2025 (Enrolled House Bill 5034), for the biennium beginning July 1, 2025, as the maximum limit for payment of expenses from fees, moneys or other revenues, including Miscellaneous Receipts, but excluding lottery funds and federal funds, collected or received by the Public Utility Commission of Oregon,

for the utility program, is increased by $463,653, to evaluate utility rate increases for electric and natural gas providers.

CAPTIONS

SECTION 16. The unit captions used in this 2025 Act are provided only for the convenience of the reader and do not become part of the statutory law of this state or express any legislative intent in the enactment of this 2025 Act.

EMERGENCY CLAUSE

SECTION 17. This 2025 Act being necessary for the immediate preservation of the public peace, health and safety, an emergency is declared to exist, and this 2025 Act takes effect on its passage.

Passed by House June 23, 2025

.....
Timothy G. Sekerak, Chief Clerk of House

.....
Julie Fahey, Speaker of House

Passed by Senate June 24, 2025

.....
Rob Wagner, President of Senate

Received by Governor:

.....M.,....., 2025

Approved:

.....M.,....., 2025

.....
Tina Kotek, Governor

Filed in Office of Secretary of State:

.....M.,....., 2025

.....
Tobias Read, Secretary of State

DEB PATTERSON
STATE SENATOR
SENATE DISTRICT 10

OREGON STATE LEGISLATURE

November 7, 2025

Chair Letha Tawney
Commissioner Les Perkins
Commissioner Karin Power
Oregon Public Utility Commission
201 High St. SE, Suite 100
Salem, Oregon 97301

Re: Utility Shutoffs Amid the Federal Government Shutdown

Dear Chair Tawney, Commissioner Perkins, and Commissioner Power,

Since the federal government shutdown began on October 1, 2025, the economic impacts have rippled throughout our economy and hurt household budgets across Oregon. Many households now face an impossible choice between buying food or paying their energy bills.

Federal employees have been on furlough or working without pay for over a month. The shutdown has delayed the distribution of Supplemental Nutrition Assistance Program (SNAP) and Low-Income Home Energy Assistance Program (LIHEAP) funds, which help families put food on the table and keep their lights on. Even though SNAP benefits are flowing again this morning, these benefits remain at risk as the shutdown drags on. If the government does not reopen by November 15, funding will also end for the Women, Infants, and Children (WIC) program, which supports pregnant people, moms, and young children.

In regular times, utility companies have shutoff policies for when customers fail to pay their utility bills. However, the federal shutdown is an unprecedented crisis that is hitting families hard, through no fault of their own. We are also entering the cold weather season, when families need access to heating. Disconnecting households from their utilities during this time would compound Oregonians' suffering and make it even more difficult for families to stay afloat.

In this extraordinarily difficult time for our state, we urge Oregon's utility companies and the Oregon Public Utility Commission to act to prevent the suspension of SNAP, LIHEAP, and other at-risk public benefits from causing utility shutoffs. Oregonians have always come together to take care of each other during times of crisis. Please adopt policies to prevent utility disconnections during the federal government shutdown.

Sincerely,

Deb Patterson

Senator Deb Patterson
Senate District 10

Senator Jeff Golden
Senate District 3

Senator Courtney Neron Misslin
Senate District 13

Senator Wlnsvey Campos
Senate District 18

Senator Mark Meek
Senate District 20

Senate Khanh Pham
Senate District 23

Senator Kayse Jama
Senate District 24

Representative Lisa Fragala
House District 8

Representative David Gomberg
House District 10

Representative Tom Andersen
House District 19

Representative Lesly Muñoz
House District 22

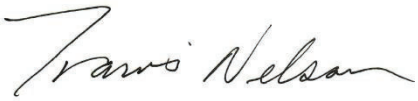
Representative Ben Bowman
House District 25

Representative Susan Rieke Smith
House District 26

Representative Nathan Sosa
House District 30

Representative Hai Pham
House District 36

Representative Daniel Nguyễn
House District 38



Representative Travis Nelson
House District 44

Representative Willy Chotzen
House District 46

NW Natural®

Rates & Regulatory Affairs

UG 527

NW Natural Alternative Rate Mechanism

Data Request Response

Request No.: UG 527 CUB DR 34

Regarding the Company's internal processes and policies surrounding the temporary November (part month) and December (full month) 2025 disconnection moratorium; Please provide all DRs in public and confidential versions, where applicable:

a. What date and under what circumstances did NW Natural realize its error?

b. Please provide an explanation and timeline of how and when (dates) the Company's Customer Service Representatives (CSRs) were trained on this 2025 disconnection moratorium temporary policy; include relevant internal communications to CSRs about this temporary policy, including Company expectations for CSRs;

c. Please provide copies and explanation of all public facing communications the Company used to inform its customers of the temporary 2025 November and December - including but not limited to, emails, letters, social media;

d. What did CSRs tell customers in the bill discount program when they called to be turned back on after disconnection?

    i. Please provide all CSR training materials for this policy

e. Please provide all CSR transcripts with Bill Discount Program customers from November and December (while protecting identifying, account holder information);

f. How many customers called the Company in November and December to inquire about the 2025 temporary disconnection moratorium?

g. How has the Company addressed this error to date? Please include what has already been done and what the Company plans to do in the future.

    i. Please include details on when the Company began reaching out to impacted customers, along with all details of the communication (email, mailed letter, phone call, voicemails); please also attach relevant examples of language used by the Company;

ii. Please explain the customer response the Company has received regarding this matter;

iii. Please include details on what relevant stakeholders it reached out to and when;

h. Does the Company plan to do public outreach regarding this error, if for no other reason than to help track down the remaining impacted customers it cannot reach to date? Please explain.

i. What bill credit and/or refund process is the Company considering? Provide relevant Commission policy/regulations/rules to support this answer.

Response:

a. NW Natural noted there were disconnection count results included in metric 5 of Table 3 in Staff's template for the Energy Burden Metric report when the report was submitted for the 4th quarter 2025 period on January 29, 2026. The Company began researching the cause for this at that time. UG 527 CUB DRs 31-32 were received on February 12, 2026, which further heightened the priority of finding the cause.

As discussed in the Company's response to UG 527 CUB DR 31, the cause was due to NW Natural not implementing the voluntary temporary winter disconnect moratorium for bill discount participants and medical certificate customers as intended. Due to an internal miscommunication, the Company continued disconnections for non-payment for these customers despite processes being put in place to do so.

b. Instruction material was developed for CSRs by November 19, 2025, but this was ultimately not communicated to the CSRs due to an administrative error. The error was the delayed approval of the CSR instruction material and lack of follow-up to secure approval. This was exacerbated by the pending retirement of a key employee, who needed to approve the material and was providing knowledge transfer during this time. By the time the follow-up for approval occurred, NW Natural had approached the normal holiday moratorium where no disconnections would take place, so the training was not deployed. The holiday moratorium in 2025 included the entire weeks of December 22 and December 31 through January 2. The instruction that should have deployed provided: "Due to the recent government shutdown, customers who are certified as low-income or have a medical certificate on file will not be routed for disconnection through January 5, 2026." Note that January 1, 2026, was a holiday and January 2-4, 2026 was a Friday and the ensuing weekend, so no disconnections would have taken place on those days, regardless of the voluntary winter moratorium.

c. NW Natural did not provide customer communications focused exclusively on the voluntary temporary winter disconnect moratorium for bill discount participants and medical certificate customers. However, the NW Natural payment assistance webpage includes a message that customers impacted by federal funding uncertainty have options available and to contact the Company for more information S

d. As noted in the response to item b above, distinct training for the voluntary temporary winter disconnect moratorium for bill discount participants and medical certificate customers was not deployed; therefore, any customer calling to reconnect after a disconnection would have received the same information as any other customer about the requirements for reconnecting service, which includes the discussion of payment assistance.

e. Please see the response to UG 527 CUB DR 36 for anonymized customer contact detail logs of the customers impacted by NW Natural's failure to implement the voluntary temporary winter disconnect moratorium.

f. NW Natural is unable to track the reasons why customers initially call the contact center, including whether customers called to ask about the voluntary temporary winter disconnect moratorium.

g. As noted in the response to UG 527 CUB DR 31, there were 192 customers that were mistakenly disconnected. To date, 171 of those customers have been reconnected, with the majority of those reconnecting the same day or next day of the disconnection. Any fees that were charged related to those reconnections have been refunded. On February 19, 2026, NW Natural reached out to the remaining customers to inform them they would be reconnected for no charge; of those customers, one customer was reconnected the same day (included in the 171), 11 customers were left voice messages, 2 customers stated they had moved and did not want to reconnect, 2 customers stated they wanted the gas to remain off and the account to remain closed, and 6 customers were not reachable due to non-working phone numbers. Note that these customer counts are system totals, consistent with the response to UG 527 CUB DR 31. The breakout of these numbers by state is as follows:

	OR	WA	Total
Total impacted	176	16	192
Reconnected (majority done same or next day)	155	15	170
pre-2/19 not yet Reconnected	21	1	22
CSST Outreach			
Reconnected 2/19	1	0	1
Customer does not want service	4	0	4
Left voicemail	10	1	11
Non-working phone numbers	6	0	6
Total	21	1	22

On February 27, 2026, NW Natural implemented a $150 bill credit for all impacted customers. The bill credit will appear on the customer's next bill as a line item with the bill message indicating: "The $150 credit on this bill corrects a service disconnection error related to a temporary pause in your service last year. This courtesy credit helps lower your bill." Customers who have closed accounts will be issued a corrected final bill that includes the credit, which will reduce the final balance and may result in a refund check.

When the error of not implementing the moratorium was confirmed, NW Natural's Vice President of Regulatory Affairs and Resource Planning reached out to the OPUC Chair and the Executive Director of Oregon CUB to inform them on or around February 19, 2026. NW Natural's Senior Manager of Regulatory Affairs also reached out to OPUC Staff's Regulatory Strategy Manager to inform them on February 20, 2026.

h. After discussion with CUB, NW Natural will be reaching out to CAPO and the community action agencies serving the areas of the remaining customers who have not returned the Company's voicemail or who have not been reached due to non-working phone numbers to assist in continuing to attempt outreach to such customers.

i. Please see the Company's response to g above.

OFFICE OF SENATOR DEB PATTERSON

FOR IMMEDIATE RELEASE

November 12, 2025

Press Contact: Megan Wai, sen.debpatterson@oregonlegislature.gov

Oregon Senator Deb Patterson and Colleagues Secure Commitments to Keep Service Connected for Struggling Families

Urging from lawmakers prompted swift action by major Oregon utility companies

SALEM, OR – Following calls from Senator Deb Patterson (D-Salem) and 17 of her legislative colleagues urging protection for struggling Oregonians during the ongoing federal government shutdown, multiple utility companies have agreed to take steps to ensure customers can stay warm.

On November 7, Senator Patterson and her colleagues delivered a letter to the Oregon Public Utilities Commission urging action to prevent utility disconnections for Oregonians affected by the federal government shutdown. Utility providers have responded quickly to share their plans to keep customers connected. Major utilities have announced measures to hold off on disconnecting service to households whose finances are hit hard by the federal shutdown.

“I’m grateful to see Oregon’s major utilities stepping up for families during this challenging time,” said Senator Patterson. “No one should be left without heat or electricity because of political gridlock in D.C.”

The Oregon Public Utility Commission has worked extensively in recent years on disconnection protections. The commission has authority to impose a moratorium on service shutoffs, but it can happen faster when utilities voluntarily make that move. Senator Patterson’s letter to Oregon’s energy-sector leaders prompted swift action.

“These agreements show what's possible when we work with local leaders to put people first,” Patterson added.

Summary of commitments:

- Pacific Power and PGE are halting shutoffs through the end of the year for income-qualified and medically vulnerable customers.
- NW Natural is suspending shutoffs through the end of the year for income-qualifying customers.
- Cascade Natural Gas is suspending collections and disconnections for 30 days for customers who receive financial utility assistance or who report they have been affected by the federal government shutdown.

- Avista Corp will provide a 30-day grace period for customers affected by the federal shutdown, which will prevent them from entering the collections process and potential shutoffs.
- Idaho Power will implement a temporary moratorium on disconnections for customers affected by the government shutdown until the federal government reopens.

Read the original letter here: bit.ly/PUC-letter.

###

Power companies to help customers impacted by government shutdown

koin.com/news/oregon/pnw-utility-companies-help-customers-impacted-government-shutdown

Michaela Bourgeois November 13, 2025

'No one should be left without heat or electricity because of political gridlock in D.C.,' Oregon State Sen. Deb Patterson said

PORTLAND, Ore. (**KOIN**) – Local utility companies have made agreements with state lawmakers to help customers who have been impacted by the federal government shutdown, Oregon State Senator Deb Patterson (D-Salem) announced.

The announcement comes after Sen. Patterson and 17 other Oregon state lawmakers **sent a letter to the Oregon Public Utility Commission** on Nov. 7, urging the organization to help protect struggling Oregonians impacted by the six-week shutdown, which came to a close on Wednesday, as reported by the **Associated Press**.

‘Like poop in my house’: Nearby residents accuse Longview paper mill of creating a big stink in lawsuit

The request was also sent to executives at PacifiCorp, PGE, NW Natural, Idaho Power, and Cascade Natural.

In response to the lawmakers, some utility providers made commitments to keep customers connected.

These commitments include decisions by Northwest Natural, Pacific Power and Portland General Electric to halt power shutoffs through the end of the year for income-qualified customers – with the latter two companies also agreeing to suspend shutoffs for medically vulnerable customers.

Additionally, Cascade Natural Gas is suspending collections and disconnections for 30 days for customers who receive financial utility assistance or for customers who report that they have been impacted by the federal government shutdown.

Avista Corp has also agreed to provide a 30-day grace period for customers affected by the shutdown to prevent customers from entering the collections process and avoid potential power shutoffs.

Further, Idaho Power is implementing a temporary moratorium on disconnections for customers affected by the shutdown until the federal government reopens.

In a press release Wednesday announcing the measures, Sen. Patterson noted that the Oregon Public Utility Commission has worked extensively in recent years to protect customers from disconnections.

The commission has the authority to impose a moratorium on service shutoffs however, Patterson noted that these measures to protect customers can happen faster when utility companies voluntarily make the move.

Parkrose Grocery Outlet workers ‘don’t feel safe’ as owner considers closing due to crime

“I’m grateful to see Oregon’s major utilities stepping up for families during this challenging time,” said Senator Patterson. “No one should be left without heat or electricity because of political gridlock in D.C.”

In a statement shared with KOIN 6 News, the Oregon Public Utility Commission said, “The Oregon Public Utility Commission (PUC) is deeply aware of the financial strain placed on many households by the federal government shutdown. Delays in federal assistance programs, in combination with seasonal heating needs, are creating heightened risk for many Oregonians. We appreciate that the investor-owned electric and natural gas companies that we regulate stepped up and quickly agreed to discontinue service shutoffs due to nonpayment for the most vulnerable customers impacted by the shutdown.”

The request comes one week after a new **NW Natural rate hike went into effect Nov. 1**, costing residents a 5.4% increase — or an average increase of $4.38. The public utility commission approved the increase after NW Natural said it needed more money to modernize its systems and construct new resource centers.

In August, **Gov. Tina Kotek signed House Bill 3179** — also known as the FAIR Energy Act — to put limits on proposed utility rate hikes in the state. This comes after customers saw **staggering increases in 2024**.

**BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. NORTHWEST NATURAL GAS CORPORATION, Respondent.	DOCKET UG-250610

RESPONSE TESTIMONY OF SHAYLEE N. STOKES

DIRECTOR OF THE ENERGY PROJECT

EXHIBIT SNS-1T

January 26, 2026

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SNS-4	NWN Response to TEP DRs 19-20
SNS-5	NWN Response to TEP DR 22
SNS-6	NWN Response to TEP DR 30
SNS-7	Julie Margetta Morgan et al., *Fueling Debt: How Rising Utility Costs Are Overwhelming American Families*, The Century Foundation (Nov. 17, 2025)
SNS-8	American Council for an Energy-Efficient Economy, *Data Update: City Energy Burdens* (Sep. 2024)
SNS-9	Sanya Carley et al., *Behavioral and Financial Coping Strategies Among Energy-Insecure Households*, 119 Proceedings of the National Academy of Sciences (No. 36 2022)
SNS-10	National Energy Assistance Directors Association, 2018 National Energy Assistance Survey Final Report, Apprise, Inc. (Dec. 2018)
SNS-11	Shuchen Cong et al., *Unveiling Hidden Energy Poverty Using the Energy Equity Gap*, 13 Nature Comms. (No. 2456 2022)
SNS-12	Mark Ellis, *Rate of Return Equals Cost of Capital: A Simple, Fair Formula to Stop Investor-Owned Utilities from Overcharging the Public*, American Economic Liberties Project (Jan. 2025)
SNS-13	Joe Daniel et al., *Rebalancing "Return on Equity" to Accelerate an Affordable Clean Energy Future*, Rocky Mountain Institute (Feb. 21, 2025)
SNS-14	Callie Ginapp et al., *Exploring the Relationship Between Debt and Health After Incarceration: A Survey Study*, J. Urban Health (Feb. 2023)
SNS-15	Rocky Mountain Institute, Utility Disconnections Handbook (Aug. 2025)
SNS-16	Diana Hernández & Jennifer Laird, *Surviving a Shut-Off: U.S. Households at Greatest Risk of Utility Disconnections and How They Cope*, 66 Am. Behavioral Scientist 00(0) (2022)
SNS-17	Paul M. Ong et al., *Keeping the Stove On: COVID-19 and Utility Debt*, UCLA Luskin Center for Innovation (Nov. 2021)

I. Introduction

Q: Please state your name and business address.

A: My name is Shaylee Nicole Stokes. My business address is P.O. Box 7130, Olympia, WA 98507.

Q: How would you like to be addressed in this proceeding?

A: You may call me Witness Stokes. I use the pronouns she, her, and hers.

Q: By whom are you employed and in what capacity?

A: I am employed by the Washington State Community Action Partnership as the Director of The Energy Project ("TEP").

Q: How long have you been employed by the Washington State Community Action Partnership?

A: I became TEP Director in September 2023. Prior to this, I was the Senior Manager of Energy Programs at Hopelink, a Community Action Agency that serves low-income families, children, seniors, and people with disabilities in King County.

Q: Would you please summarize your professional background as it relates to low-income programs?

A: I have been involved in the administration and design of low-income programs for more than a decade. Hopelink hired me in 2010 to screen customers for energy assistance, review customers' energy assistance applications, and award energy assistance grants to low-income customers. Over time, I moved into a management role, training front-line staff in the administration of energy assistance procedures and approving payments. By the time of my departure in 2023, I was the Senior Manager of Energy Programs, leading a staff of more than 30 in the day-to-day administration of energy assistance programs. In

2024, I was selected to serve on the Governance Board of the National Energy & Utility Affordability Coalition. I hold a Bachelor of Arts from the University of Washington in Seattle, WA. I have been a member of Northwest Natural Gas's ("NWN" or "Company") low-income advisory group and energy efficiency advisory group since 2023.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of TEP, an intervenor in this proceeding that represents the interests of low-income customers and vulnerable populations. TEP works with Community Action Agencies ("CAAs" or "agencies") that provide low-income weatherization and bill payment assistance for customers in NWN's service territory.

Q: Have you previously testified before the Washington Utilities and Transportation Commission ("Commission" or "WUTC")?

A: Yes. I previously provided testimony concerning PacifiCorp's 2023 General Rate Case, Docket UE-230172; PacifiCorp's Clean Energy Implementation Plan, Docket UE-210829; Puget Sound Energy's 2022 General Rate Case, Docket UE-220066/UG-220067; Puget Sound Energy's 2024 General Rate Case, Docket UG-240004/UG-240005; Avista Corporation's 2024 General Rate Case, Docket UE-240006/UG-240007; Cascade Natural Gas's 2024 General Rate Case, Docket UG-240008; and PacifiCorp's 2025 Power Cost Only Rate Case, Docket UE-250224. I also previously provided public comments at UTC meetings and have worked closely with Commission staff on numerous occasions.

Q: Are you sponsoring any exhibits?

A: Yes. As described in the exhibit list, I am sponsoring exhibits SNS-2 through SNS-17.

Q: Please describe the scope of your testimony.

A: My testimony primarily concerns NWN's low-income customer service, including issues related to equity, affordability, and rates.

Q: Could you please summarize your testimony?

A: Yes. My testimony concerns issues related to equity, affordability, low-income customer service, and NWN's rate and recovery proposals.

First, I discuss the equity concerns driving my testimony and TEP's involvement in this rate case. This portion of my testimony focuses on the ways in which economic pressures have outsized impacts on low-income utility customers and identifies NWN's and the Commission's obligations to consider the unique needs of low-income customers in this case.

Second, I explain why the Commission should reject NWN's proposed residential basic charge increase due to equity concerns. I identify how NWN's own testimony shows the increase will cause an overall bill increase for low-income customers, and I discuss the impacts of higher fixed charges on low-income customers, who tend to use less natural gas than higher-income customers. I discuss the available literature that documents the coping strategies low-income customers use to adapt to higher bills and the safety concerns that stem from these strategies.

Third, I discuss my concerns with NWN's proposed return on equity ("ROE") and advocate for a lower ROE that takes into account recent Federal Energy Regulatory Commission ("FERC") decisions rejecting the Risk Premium and Expected Earnings analyses, two common economic models the Commission has used to set ROEs in the past. Based on the testimony of the non-company parties in this case, the Commission

should take a fresh look at its ROE paradigm because its earlier decisions too heavily favor the interests of shareholders over ratepayers.

Fourth, I discuss the need for energy assistance in NWN's service territory and how inflation has amplified affordability concerns for low-income NWN ratepayers. I explain how NWN's current method of communicating with the agencies that implement its low-income programs lacks needed functionality and should be replaced by a secure access portal. I also praise NWN's implementation of its bill discount and arrearage relief programs.

Fifth, I summarize NWN's residential disconnection policies and identify specific policies that are inequitable. Under NWN's current disconnection thresholds, a customer who has maintained a past-due balance as small as $150 for as few as 14 days is eligible to be routed toward disconnection. This low threshold disproportionately burdens low-income customers. Further, NWN's practice of allowing collections agencies to report customer credit info to credit bureaus results in unnecessary punishment of low-income customers. I describe the Commission's equity lens, which uses the four energy justice tenets to evaluate if a policy is in the public interest, and recommend that NWN use this equity lens to review its disconnection policies. Specifically, I recommend the Commission order NWN to (1) prohibit disconnection for customers owing less than $300; (2) not initiate disconnection procedures until a customer bill is at least 60 days past due; (3) prohibit the collections agencies NWN works with from reporting to credit bureaus; and (4) permanently remove fees and deposits currently waived per the term sheet in the Commission's COVID-19 docket (U-200281), and then modify NWN's billing system to end the inefficient and inconsistent manual refunds of fees.

Sixth, I detail how NWN can improve its ability to meet its customers' language access needs. NWN has taken several good first steps to improve language access, including offering translation services upon request and providing written materials to customers in preferred languages. Nevertheless, data show that NWN likely still undercounts customers who would prefer services in a language other than English. Also, NWN has no comprehensive framework in place to identify language access needs. I recommend the Commission order NWN to track customers' language preferences and adopt a language access plan to proactively meet its customers' language access needs.

Seventh, I recommend the Commission reject NWN's proposal to recover deferred costs from (1) late payment and reconnection fees not charged to customers and (2) other direct costs, like COVID-19 costs related to personal protective equipment and cleaning supplies. NWN's proposal would result in customers paying an apportioned late fee on charges that were already waived. Moreover, NWN's proposal to recover direct costs related to COVID-19 measures is fundamentally inequitable, as it requires customers who already bore those costs for themselves to additionally cover NWN's costs.

Eighth, I recommend NWN revise two of its proposed Performance-Based Ratemaking ("PBR") metrics and include two additional metrics in its reporting. The changes I recommend would clarify NWN's reporting on customers in arrears, better align reporting on utility assistance program effectiveness with current implementation trends, and ensure NWN reports all Commission-endorsed Policy Statement metrics. Additionally, I recommend NWN post its PBR metrics on its public website.

Ninth, I highlight uncertainties that remain regarding NWN's proposed Thermal Energy Network ("TEN") and the rate base merger NWN proposes to pay for that project. TEP cannot support merging the rate base or the proposed project without knowing whether the project would serve low-income customers and how much of the cost natural gas customers would bear. I urge the Commission to emphasize the equity factors in the law governing the proposed rate base merger.

II. Low-income customers are disproportionately impacted by inequitable utility service.

Q: What is the purpose of your testimony today?

A: Achieving equitable treatment and affordable service for low-income residential customers and vulnerable populations is TEP's fundamental goal in its work with utilities and other stakeholders in Washington. TEP's unique role as intervenor in this rate case is to advance this goal. Washington law allows the Commission to consider equity as a part of its public interest standard for decision making.[1] The Commission has recognized the importance of applying an "equity lens in all public interest considerations" to remedy systemic harms to vulnerable populations.[2] An equity lens focuses on characteristics "for which groups of people have historically, and are currently, marginalized."[3] Energy justice and its core tenets, including distributional, procedural, recognition, and restorative justice, are integral standards and sources of insight as the Commission

[1] RCW 80.28.425(1).

[2] *WUTC v. Cascade Natural Gas Corp.*, Dkt. UG-210755, Final Order 09 Adopting Settlement Agreement Subject to Conditions, ¶ 58 (Aug. 23, 2022) (hereinafter "Cascade 2021 GRC Order") ("So that the Commission's decisions do not continue to contribute to ongoing systemic harms, we must apply an equity lens in all public interest considerations going forward.").

[3] *Id*. (citing RCW 43.06D.010(4)).

applies its equity lens.[4] The Commission specifically seeks to ensure that utility policy is "addressing historic underinvestment and exclusionary policies and practices that have allowed inequity to flourish."[5] Regulated companies must assess whether proposed modifications to their practices correct or perpetuate inequities.[6]

Throughout my testimony, I emphasize the importance of assessing the impact of NWN's proposals and practices on low-income customers through the Commission's equity lens.[7]

Q: What kinds of equity concerns are particularly relevant to the Commission's decisions in this rate case?

A: The data I provide below shows that low-income customers and vulnerable populations are disproportionately impacted by economic pressures like inflation and utility rate increases, in part because of their budget-limited ability to adapt to financial stressors. The Commission should consider that for many households in these communities, higher energy bills or utility disconnections are not merely financial inconveniences; they pose real safety hazards and have cascading economic and other effects with uncertain or

[4] *Id*. ¶ 56.

[5] *Id*. ¶ 57 (citing WA Gov. Executive Order 22-04: Implementing the Washington State Pro-Equity Anti-Racism (PEAR) Plan and Playbook).

[6] *Id*. ¶ 58.

[7] Dkt. A-230217, Interim Policy Statement Regarding Procedural Justice, ¶ 6 (May 12, 2025) ("It is clear the legislature and Governor's Office recognize the need to effectively identify named communities, and to coordinate, plan, and implement policies to help decision-makers avoid perpetuating inequities on communities in Washington.").

extended recovery times. Recent research shows low-income families nationwide are already experiencing rising utility debt.[8]

Q: Do high utility bills have disproportionate impacts on low-income customers?

A: Yes. In its deliberations, the Commission should consider that inflation disproportionately impacts low-income households. Lower-income households have a higher average utility burden than the average household. NWN's 2024 energy burden assessment ("EBA") demonstrates that NWN's Washington residential customers are carrying $7.3 million in excess energy burden (i.e., energy assistance need).[9] Low-income households make up 23% of NWN's Washington service territory, but they carry about 80% of this total energy assistance need.[10] This figure is consistent with national data showing that low-income households have energy burdens that are about three times higher than the median household burden.[11]

At the same time, low-income households experience the pressures of inflation more acutely and severely than other households do. The U.S. Department of Labor's Bureau of Labor Statistics ("BLS"), the agency that calculates and reports the "rate of inflation" (i.e., the Consumer Price Index) each month, reports that "consumers with

[8] Exh. SNS-7 at 2-4 (Julie Margetta Morgan et al., *Fueling Debt: How Rising Utility Costs Are Overwhelming American Families*, The Century Foundation (Nov. 17, 2025)).

[9] Exh. CJT-3 at 24.

[10] *Id.* at 23-24.

[11] Exh. SNS-8 at 2 (American Council for an Energy-Efficient Economy, *Data Update: City Energy Burdens* (Sep. 2024) (finding low-income households spent a median of 8.3% of annual income on energy bills, while the overall household median was 2.9%)).

different incomes experience inflation quite differently."[12] According to this research, as shown in the table below, households earning lower incomes spend a higher share of their household budget on necessities such as rent, food, and medical care.

Table 1. Household budget shares of expenditure items for lowest and highest income quartiles, 2017-2018[13]

Expenditure	Lowest Income Quartile	Highest Income Quartile
Rent or owner's equivalent	34.93%	27.93%
Food at home	9.44%	6.58%
Medical care	8.36%	8.09%
Household utilities	4.36%	2.73%
Motor fuels	3.46%	3.42%
Motor vehicle operation	3.44%	3.40%
Telephone service	2.32%	2.00%

Prices for those necessities also rise faster than for other products.[14] As a result, lower income households tend to face higher rates of inflation.[15] According to an independent analysis of BLS consumer price index statistics, prices have risen about 10% faster from 2005 to 2024 for low-income households compared to average households.[16] Not

[12] Joshua Klick & Anya Stockburger, *Spotlight on Statistics: Inflation Experiences for Lower and Higher Income Households*, U.S. Dept. of Labor, Bureau of Labor Stats. (Dec. 2022), https://www.bls.gov/spotlight/2022/inflation-experiences-for-lower-and-higher-income-households/home.htm.

[13] *Id*.

[14] *Id.*

[15] *Id*.

[16] Jeff Horwich, *Lower Income, Higher Inflation? New Data Bring Answers at Last*, Federal Reserve Bank of Minneapolis (Oct. 7, 2024), https://www.minneapolisfed.org/article/2024/lower-income-higher-inflation-new-data-bring-answers-at-last.

surprisingly, household income is a key driver of whether inflation is experienced as "very stressful."[17] Low-income families cannot adapt to rising prices easily because they already tend to conserve spending and cannot afford to stock up on goods before prices spike.[18]

These concerns about the disproportionate impacts of rising prices carry over directly to the price of utilities like natural gas. Low-income customers of utilities are less able to afford rising energy bills and are more likely to employ risky coping strategies when bills are too high. Households that have recently been disconnected or otherwise experienced energy insecurity are more likely to take measures like avoiding heating their homes because of the expense, or foregoing spending on necessities like medication and food in order to pay their utility bills.[19]

Q: Do these concerns extend to NWN's customers?

A: Yes. TEP recognizes that NWN has taken significant steps toward addressing concerns low-income customers present regarding energy affordability. NWN witness Cecilia Tanaka's list of NWN's equity and affordability programs in her direct testimony demonstrates NWN is making progress.[20] And TEP appreciates that NWN's initial implementation of its bill discount program and arrearage forgiveness grant has been

[17] Aparna Jayashankar & Anthony Murphy, *High Inflation Disproportionately Hurts Low-Income Households*, Federal Reserve Bank of Dallas (Jan. 10, 2023), https://www.dallasfed.org/research/economics/2023/0110.

[18] *Id.*

[19] Exh. SNS-9 at 2-4 (Sanya Carley et al., *Behavioral and Financial Coping Strategies Among Energy-Insecure Households*, 119 Proceedings of the National Academy of Sciences (No. 36 2022) (hereafter "*Coping Strategies*").

[20] Tanaka, Exh. CJT-1T at 8:1-8:3 & tbl.1.

successful, resulting in a high number of customers receiving discounted bills and grants.[21] However, as reflected in the results of NWN's EBA, the low-income customers in NWN's service territory are still struggling with economic pressures made worse by high energy bills. In NWN Witness Tanaka's words, NWN must "operationalize equity" in its rates and policies that effect low-income and vulnerable populations.[22] TEP's recommendations are intended to help NWN do that.

Q: How should these equity concerns factor into the Commission's decisions in this case?

A: I urge the Commission to ensure NWN's rates and policies remedy, rather than worsen, unfair or disproportionate burdens on low-income utility customers. This includes ensuring equitable rate design, rate of return, disconnection policies, language access policies, COVID-19 policies, and performance-based metrics. In doing so, I urge the Commission to follow the core principles of energy justice. These principles, which include distributional, procedural, recognition, and restorative justice, are integral standards and sources of insight as the Commission applies its equity lens.[23]

III. The Commission should reject Northwest Natural's proposed fixed charge increase because it will disproportionately impact low-income residential customers.

Q: Please describe NWN's proposed increase in its fixed charge.

[21] *Infra* Section V.

[22] Tanaka, Exh. CJT-1T at 10:19-10:23 ("The WUTC's evolving regulatory framework . . . requires natural gas utilities to operationalize equity across all 20 aspects of planning, ratemaking, and customer engagement. Each tenet of equity requires new data systems, stakeholder engagement models, and internal capacity to interpret and act on community input.")

[23] Cascade 2021 GRC Order, ¶ 56.

A: NWN proposes to significantly increase its fixed charge for both its residential schedules: Rate Schedule 1 Residential ("RS 1 Residential") and Rate Schedule 2 ("RS 2").[24] NWN's proposal includes raising the fixed charge from $5.50 to $10 for RS 1 Residential, and from $8 to $10 for RS 2, over two rate years ("RYs").[25] NWN's proposal represents a more than an 80% increase for RS 1 Residential and a 25% increase for RS 2.

Q: Do you have any concerns with this proposal?

A: Yes. This proposed increase will disproportionately negatively impact low-income customers. I thus recommend that the Commission deny the request. In presenting this analysis, I first document the fact that low-income customers tend to have lower usage levels than residential customers generally. While I do not assert that all low-income customers are also low use customers, I do conclude that low-income customers tend to be, and are disproportionately, also low use customers. Income and energy usage are directly related. As low use customers, low-income customers will be disproportionately harmed by the proposed increase in the fixed charge. In addition, I consider the ways in which the fixed charge impedes the ability of low-income customers to respond to higher bills through a reduction in their consumption.

[24] NWN uses two separate rate schedules for different types of residential customers. NWN Tariff WN U-6, Schedules 1 & 2. A residential customer *without* gas equipment that qualifies as a primary heating system under RS 2 falls under RS 1 Residential. A residential customer *with* gas-fired equipment that is the primary source of space heating requirements falls under RS 2. NWN does not collect information regarding relative incomes of RS 1 Residential and RS 2 customers. Exh. SNS-5 (NWN Response to TEP DR 22). Based on NWN's understanding of the two schedules, neither schedule appears skewed toward customers of a certain income level; therefore, TEP objects to the rate increase request for both.

[25] Wyman, Exh. RJW-1T at 65:21-66:3.

Q: What data supports your conclusion that low-income customers tend to use less natural gas?

A: A wide range of sources support this conclusion, as TEP's filings in prior Commission proceedings have demonstrated.[26] The U.S. Department of Labor's annual Consumer Expenditures Survey ("CEX"), which provides data on natural gas expenditures by income level, is particularly instructive. The table below uses data from the CEX organized by two measures of income: absolute dollars and deciles.[27]

Table 2. Natural Gas Expenditures by Income (2024)
(Consumer Expenditures Survey Tables 1203 and 1110)

Less than $15,000	$15,000 to $29,999	$30,000 to $39,999	$40,000 to $49,999	$50,000 to $69,999	$70,000 to $99,999	$100,000 to $149,999	$150,000 to $199,999	$200,000 and more
$230	$322	$373	$436	$438	$480	$553	$655	$806

Lowest 10 percent	Second 10 percent	Third 10 percent	Fourth 10 percent	Fifth 10 percent	Sixth 10 percent	Seventh 10 percent	Eighth 10 percent	Ninth 10 percent	Highest 10 percent
$226	$350	$372	$449	$425	$491	$540	$569	$668	$834

[26] *See WUTC v. Cascade Natural Gas Corp.*, Dkt. UG-240008, Stokes, Exh. SNS-1T at 46:13-47:4 (Sep. 25, 2024); *WUTC v. Avista Corp.*, Dkts. UE/UG-240006/07, Colton, Exh. RDC-1T at 64-77 (Jul. 3, 2024); *WUTC v. Puget Sound Energy*, Dkts. UE/UG-240004/05, Colton, Exh. RDC-1T at 62-74 (Aug. 6, 2024); *WUTC v. Puget Sound Energy*, Dkts. UE/UG-220066/67, Pfeiffer-Rosenblum, Exh. APR-1T at 14-15 (Dec. 8, 2022).

[27] Bureau of Labor Statistics, Consumer Expenditures Surveys, Tables 1110 and 1203 (2024) (Table 1110: https://www.bls.gov/cex/tables/calendar-year/mean-item-share-average-standard-error/cu-income-deciles-before-taxes-2024.xlsx; Table 1203: https://www.bls.gov/cex/tables/calendar-year/mean-item-share-average-standard-error/cu-income-before-taxes-2024.xlsx).

As the above table shows, as income decreases, household natural gas expenditures decrease as well.

Q: How does the conclusion that lower-income customers use less gas prove such customers will be disproportionately impacted by NWN's fixed charge increase?

A: The disproportionate impact is twofold. First, a higher fixed charge means more of a customer's bill is not dependent upon usage; this impedes the ability of low-income customers to control their natural gas bills by reducing their usage. Second, NWN's higher fixed charge will result in a net bill increase for low-usage customers, while providing a net bill decrease for higher-usage customers. Because low-income users tend to use less gas than average, this is an inequitable result because it benefits higher-income customers at the direct expense of low-income customers.

Q: Regarding the first impact you identified, what do you mean when you discuss low-income customers' efforts to reduce usage?

A: Customers who have recently faced energy insecurity are more likely to forego spending on necessities, avoid using heat in their home despite cold temperatures, and take other potentially dangerous measures to avoid high energy bills.[28] Research indicates that low-income households seek to reduce bills by closing off parts of their homes, lowering heating temperatures, or substituting ovens or stoves to heat their homes. By "reducing usage," I refer not just to energy efficiency improvements like weatherization, but to these risky measures as well.

The most recent National Energy Assistance ("NEA") survey published by the NEA Directors Association provides detail on what kinds of actions low-income

[28] Exh. SNS-9 at 2-4 (*Coping Strategies*).

customers take to reduce energy bills they can't afford, and how often they do so.[29] Between one in three and one in five low-income customers (ranging between 0% and 150% of the federal poverty line ("FPL")) close off parts of their home in at least some months.[30] One in four households below 50% FPL reduce the temperature in their homes to unsafe or unhealthy levels in at least some months.[31] At least one out of ten low-income customers use their kitchen stove or oven to heat their homes.[32] Households under 50% FPL are the most likely to take these actions almost every month. The table below illustrates the findings of the NEA survey.

Table 3. Energy Reduction Actions in Response to Inability-to-Pay by Range of Federal Poverty Level (each attributed to "not having enough money to pay energy bill")[33]

	Closed Off Part of Home			Kept Temp at Unsafe or Unhealthy Level			Used Kitchen Stove or Oven to Heat		
	0-50%	51-100%	100-150%	0-50%	51-100%	100-150%	0-50%	51-100%	100-150%
Almost every month	10%	14%	7%	8%	3%	3%	1%	1%	1%
Some months	24%	13%	14%	18%	12%	10%	14%	11%	8%
1 – 2 months	12%	10%	11%	7%	8%	9%	22%	19%	14%
Never / No	54%	63%	67%	67%	76%	76%	63%	69%	77%
Don't know/refused	0%	0%	<1%	0%	1%	2%	0%	0%	1%

[29] Exh. SNS-10 at 6 (NEA Directors Association, 2018 National Energy Assistance Survey Final Report, Apprise, Inc. (Dec. 2018)).

[30] *Id.* at 20 (tbl.IV-7C).

[31] *Id.* at 22 (tbl.IV-8C).

[32] *Id.* at 23 (tbl.IV-9C).

[33] *Id.* at 20, 22, 23.

These data show low-income customers frequently take unsafe and unhealthy actions to reduce utility bills. A range of other research supports this conclusion.[34] The conclusion is also documented in public comments to Commission proceedings.[35] It is unreasonable and inequitable for NWN to make it even more difficult for low-income households to reduce their bills when those households are already forced to resort to heating their homes (or only a portion of their homes) using their kitchen stove or oven, or keep their homes at unsafe or unhealthy temperatures because they cannot afford to pay their bills.

NWN's proposal to increase the fixed monthly charge makes a higher part of the bill unavoidable, resulting in less flexibility for low-income customers who are already taking sometimes drastic measures to cut costs. But these customers cannot afford *not* to take these measures. As a result, the fixed charge increase will incentivize more intense usage reduction measures, increasing risks to low-income customers.

Q: As to the second type of impact you identify, what evidence supports your conclusion that NWN's higher fixed charge will result in a net bill increase for low-income customers?

A: First, NWN Witness Robert J. Wyman's testimony admits the fixed charge increase will shift more of the cost burden onto lower-usage customers. Wyman welcomes this outcome, as it avoids "intra-class subsidization that flows from the higher usage

[34] *See, e.g.*, Exh. SNS-9 at 5 (*Coping Strategies*); Exh. SNS-11 at 7-8 (Shuchen Cong et al., *Unveiling Hidden Energy Poverty Using the Energy Equity Gap*, 13 Nature Comms. (No. 2456 2022)).

[35] *See, e.g.*, *WUTC v. Avista Corp.*, Dkt. UE/UG-240006/07, Exh. BR-1, Public Comment Exhibit, Attach. 2 at 4 (Oct. 8, 2024) (letter from customer describing using no heat in winter "until I'm very chilled" to cut costs, and no air conditioning in summer despite needing to sleep with a wet towel in 100-degree heat).

customers to the lower usage customers."[36] As I have explained, however, low-usage customers will tend to be lower-income. This reduction in "intra-class subsidization" means lower-income customers will shoulder a greater portion of the cost burden of gas service.

Second, NWN's own data shows that bills would rise for both average-use customers and lower-use customers under its proposal. The proposed fixed charge increase will raise the bill for RS 1 Residential customers using the average of 14.6 therms per month by 63 cents.[37] RS 1 Residential customers who use less would pay even more. RS 1 Residential customers enrolled in the bill discount program who use less than 14.5 therms in winter (about 40% of such customers) would have higher bills in every month of the year.[38] For RS 2 customers, the proposed fixed charge increase would slightly raise bills for average-usage customers (54.5 therms/month in RY 1; 54.1 therms/month in RY 2).[39] It would raise bills in every month of the year for customers at each bill discount tier.[40]

Wyman focuses heavily on distinguishing certain months in which lower bills are expected for some customers as a result of the fixed charge increase.[41] However, despite Wyman's focus on the higher-usage customers who will see lower bills in winter, low-

[36] Wyman, Exh. RJW-1T at 71:19-71:21.

[37] *Id.* at 73:5-73:7; *see* Exh. RJW-18 at 1:7, 1:9, 4:7, 4:9. This exhibit is a table that displays the average normal monthly use of RS 1 and RS 2 customers. The average for RS 1 Residential is 14.6 therms/month; RS 2 is 54.5 therms/month in RY 1 and 54.1 therms/month in RY 2.

[38] Wyman, Exh. RJW-1T at 74:1, tbl.5.

[39] Exh. RJW-18 at 1:9, 4:9.

[40] *Id.* at 79:12, tbl.8.

[41] Wyman, Exh. RJW-1T at 81:4-81:23.

usage customers will face higher bills all year.[42] As Wyman admits, low-usage customers (who tend to be low-income) will pay a larger share of the cost of service compared to the current fixed charge scenario.

Q: What do you conclude?

A: NWN's proposed fixed charge increase will raise bills for low-income residential customers and encourage more intense, risky usage reduction measures. NWN's own testimony shows that its proposal will put a higher proportionate cost burden on low use, lower-income customers. This is an inequitable result. The Commission should reject NWN's proposal.

If the Commission is inclined to allow any increase in the fixed charge, I alternatively recommend that the Commission embrace the regulatory principle of gradualism and only allow an increase of only $0.15-0.25 for the fixed charge during the rate plan. As it stands, NWN's proposal to raise its fixed charge by more than 80% for RS 1 Residential and by 25% in one year for RS 2 contradicts that principle and the Commission should reject it on that basis, if on no other.

IV. The Commission should reject Northwest Natural's requested Return on Equity.

Q: What ROE is NWN requesting?

A: NWN is requesting a ROE of 10.1% in RY 1, phasing to 10.2% beginning in RY 2.[43] This is based on NWN's estimation that its cost of equity is between 10% and 11%.[44]

Q: What are your concerns with this proposed ROE?

[42] *Id.* at 76:7-76:12; 80:12-80:18.

[43] Nelson, Exh. JEN-1T at 5:1-5:3.

[44] *Id.* at 4:7-4:9, 80:19-80:21.

A: My primary concern is that the proposed ROE will adversely impact low-income customers by adding to their energy burdens. NWN's current ROE, which the Commission approved in 2021, is 9.4%.[45] NWN thus asks for a 0.8% hike in ROE in this rate case. My understanding is that a significantly higher ROE will support a significantly higher revenue requirement for NWN, which will result in faster-growing natural gas bills for customers. I am not an expert in the field of setting utility profit margins. Nevertheless, setting a fair ROE is one lever the Commission can use to benefit *all* customers. Because of the significant increase NWN seeks in this case, I urge the Commission to apply heavy scrutiny to the ROE lever here, as the Commission's decision will impact the entire NWN customer base, including low-income customers.

Q: What specifically do you want the Commission to consider in setting a ROE for NWN?

A: Because it impacts rates, the ROE must be set in light of the Commission's obligation to ensure rates are fair, just, reasonable, and sufficient.[46] Moreover, the Commission must weigh the interests of ratepayers against those of NWN's investors in setting a just and reasonable ROE.[47] In recent years, investor-owned utility ("IOU") residential rates have increased almost 49% more than inflation.[48] If inflation rates are not a significant

[45] *WUTC v. NWN*, Dkts. UG-200994/95/96 & UG-210085, Order 05 Approving and Adopting Settlement Agreement, ¶ 31 & n.12 (Oct. 21, 2021).

[46] RCW 80.28.010(1).

[47] *See Federal Power Comm. v. Hope Natural Gas Co.*, 320 U.S. 591, 602-03 (1944) ("The ratemaking process under the Act, *i.e.,* the fixing of "just and reasonable" rates, involves a balancing of the investor and the consumer interests.").

[48] Exh. SNS-12 at 2 (Mark Ellis, *Rate of Return Equals Cost of Capital: A Simple, Fair Formula to Stop Investor-Owned Utilities from Overcharging the Public*, American Economic Liberties Project (Jan. 2025)).

predictor of recent rate growth, we must critically examine cost driver correlation among other strata, including within institutionalized utility profit structures. Recent research finds a correlation between growth in rates relative to inflation and growth in ROEs relative to prevailing interest rates and cost of capital.[49] This correlation between increased ROEs and increased rates indicates the balance of ratepayer interests and investor interests has tipped too far in favor of investors. The purpose of this part of my testimony is to highlight how rapidly rising utility rates are driven in part by high ROEs. I also advocate for the Commission to rebalance its approach to setting ROE in a way that appropriately considers ratepayer interests (and, thereby, equity concerns of low-income customers who cannot afford higher rates).

I expect the other non-company parties in this case will raise important issues concerning the cost of capital, and I urge the Commission to seriously consider all their proposals. Among these may be concerns about the economic models the Commission uses to evaluate proposed ROEs. FERC has recently rejected the use of two models to justify ROE: the Risk Premium model and the Expected Earnings model.[50] FERC found the Risk Premium model is not actually used in financial circles and is an unreliable indicator of costs,[51] and it found the Expected Earnings model is inconsistent with

[49] *Id.* at 8-9; Exh. SNS-13 at 2 (Joe Daniel et al., *Rebalancing "Return on Equity" to Accelerate an Affordable Clean Energy Future*, Rocky Mountain Institute (Feb. 21, 2025)); *see WUTC v. Avista Corp.*, Dkts. UE/UG-240006/07, Initial Post-Hearing Brief of Public Counsel, ¶ 84 & n.236 (Oct. 28, 2024) (citing studies finding excess growth in returns on equity going back to 1980).

[50] *See* 189 FERC ¶ 61,036 at 16 (Oct. 16, 2024) (rejecting Risk Premium model for determining ROE); 169 FERC ¶ 61,129 at 103 (FERC Opinion No. 569) (Nov. 21, 2019) (rejecting Expected Earnings model for determining ROE).

[51] 189 FERC ¶ 61,036 at 16.

Supreme Court precedent.[52] NWN uses a Risk Premium-based model in this rate case to justify its requested ROE.[53] Unless the Commission has reason to believe that FERC's decisions are legally or factually erroneous, it should follow FERC's precedent and not use these two models in its decision-making.

In conclusion, the UTC's paradigm for ROE analysis is ripe for reevaluation based on the non-company parties' testimony in this case. I encourage the Commission to seriously consider other parties' proposals to avoid adding to the affordability crisis for low-income ratepayers.

V. The Commission should ensure Northwest Natural is effectively implementing its low-income programs and thoroughly assessing its customers' bill assistance need.

Q: How would you describe the low-income population in NWN's service territory?

A: As a result of TEP's prior advocacy, NWN's energy assistance programs now use the same definition of low-income as the other IOUs in Washington. Customers can access low-income programs if their household income is at or below 200% of the FPL or 80% of AMI, whichever is higher. NWN's 2024 EBA shows that about 23% of households in NWN's service territory in Washington qualify as low-income.[54] The EBA also estimates about 18,000 out of a total of 78,000 households that are NWN customers in Washington qualify as low-income.[55]

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[52] 169 FERC ¶ 61,129 at 103 (discussing requirement to "analyze the returns that are earned on 'investments in other enterprises having corresponding risks,'" (quoting *Hope Natural Gas Co.*, 320 U.S. at 603)).

[53] Nelson, Exh. JEN-1T at 22:15-22:18.

[54] Exh. CJT-3 at 22.

[55] *Id.* at 50.

Q: Please explain the concepts of total energy burden and gas bill burden.

A: Energy burden is the percent of a household's total income spent on all energy expenses. Energy expenses typically include only electric and natural gas bills, but sometimes also wood, fuel oil, bottled gas, or other heat sources. By contrast, a gas bill burden is the percent of a household's income that is spent on a natural gas bill.

Q: How do you assess the level of need for low-income energy assistance in NWN's service territory in Washington?

A: NWN only provides natural gas service, so its affordability can be measured by examining the natural gas bill burden only, as opposed to total energy burden. Through the Department of Commerce and UTC's Clean Energy Transformation Act rulemakings, the state has standardized a measure of high energy burden at 6% total income.[56] However, the state has not standardized a measure of single-fuel natural gas bill burden. In my testimony in the Cascade Natural Gas 2024 rate case, I summarized Cascade data that showed electric burdens for Cascade's service territory made up about 60% of the total household energy burden, while natural gas bill burdens made up about 40% of the total energy burden.[57] Thus, there I concluded that a 2% natural gas bill burden should be characterized as a high burden.[58] Here, NWN's EBA considers a household's gas burden "high" if it is above 2% in "marine climate counties" and above 3% in "cold climate counties."[59] TEP has reservations about the soundness of this approach. It makes sense

[56] WAC 194-40-030 and WAC 480-109-060(14).

[57] *WUTC v. Cascade Natural Gas Corp.*, Dkt. UG-240008, Stokes, Exh. SNS-1T at 8:2-8:7 (Sep. 25, 2024).

[58] *Id.* at 8:10.

[59] Exh. CJT-3 at 10.

that customers in colder climates may have increased natural gas usage on average, but that does not decrease electric usage or change the 6% total energy burden threshold. It seems more consistent with a total energy burden framework to expect climate to have a larger impact on energy burden in cold zones compared to marine zones, potentially resulting in more energy-burdened customers in colder areas, rather than to expect natural gas users in colder zones to spend a greater percentage of their total income on gas before they are considered highly burdened by those bills. Compared to the 2% threshold TEP has used, NWN's 2/3% approach is somewhat high, but it is still useful as a low-end approximation of excess gas bill burden. The EBA finds that about 13,000 households have a high gas bill burden based on the 2/3% threshold it uses.[60] EBA estimates the median low-income gas burden is 2.2% among NWN's Washington residential customers.[61] This means the average low-income household served by NWN in Washington has a high energy burden. Because this data relies on average burdens, there are some customers with more extreme energy burdens, and others with lower burdens. Regardless, these data show a continued substantial need to help NWN's low-income customers better afford their gas bills. In total, the EBA estimates $5.9 million of excess gas bill burden for low-income NWN customers in Washington.[62] This is a significant gap.

Q: What steps is NWN taking to close this gap?

[60] *Id.* at 24; Tanaka, Exh. CJT-1T at 23:1, tbl.6.

[61] Exh. CJT-3 at 44.

[62] *Id.* at 24.

A: TEP appreciates the efforts NWN is already making to address the bill assistance needs in its Washington territory. TEP is aware of, and credits NWN for, the equity-focused actions NWN is taking, as summarized in Witness Tanaka's direct testimony.[63]

In particular, TEP appreciates NWN's efforts to implement its relatively new bill discount program in Washington, which launched in 2024. The program provides tiered bill discounts of up to 80% depending on a customer's household income.[64] NWN automatically enrolled customers who accessed energy assistance in the past two years.[65] NWN also performed commendable community outreach supporting its bill discount program. Enrollment rates in the program (due to this outreach and the automatic enrollment, among other factors) are the best among all the IOUs in Washington: 8,982 customers, or roughly 50% of low-income customers, as of May 2025.[66] My understanding is that this enrollment figure has increased since. The high enrollment is a strong signal that NWN is succeeding in rolling out this bill discount program. Additionally, TEP commends NWN on successfully starting to implement its Arrearage Management Program, which launched in April 2025 and has delivered over $85,000 in utility debt forgiveness since then.[67] This performance corresponds directly to the Commission's proposed performance metric regarding customer participation in

[63] Tanaka, Exh. CJT-1T at 8:1, tbl.1.

[64] *Id.* at 12:7-12:16, tbl.2.

[65] *Id.* at 14:8-14:12.

[66] *Id.* at 13:2-13:7.

[67] *Id.* at 24:10-24:12.

assistance programs, which is a key metric for TEP and which NWN proposes to report in this rate case.[68]

Q: What additional steps do you propose NWN take to better understand and respond to the excess energy burden in its Washington territory?

A: First, the Commission should require NWN to provide more frequent and detailed information on energy burdens in its Washington territory. Second, the Commission should order NWN to work with its Gas Residential Energy Assistance Tariff ("GREAT")[69] Advisory Group to plan for the creation of a secure access portal for the agencies that implement NWN's low-income programs in Washington (i.e., Washington Gorge Action Programs ("WAGAP") and Clark Public Utility District ("Clark PUD") (collectively, "the agencies")). The purpose of this access portal is to improve the agencies' ability to efficiently provide low-income assistance to more customers. NWN's current system lacks several levels of important functionality, which I discuss more below.

Q: As to the first request, what additional energy burden data do you propose NWN report?

A: TEP recommends that NWN regularly perform an energy burden analysis that includes an assessment of stratified energy burdens and identifies excess burdens. TEP recognizes and commends NWN for its efforts in producing the 2024 EBA, which is useful in determining excess energy burdens. Additionally, TEP recognizes that NWN is already

[68] *See* Siores, Exh. NCS-1T at 5, tbl.1.

[69] *See* Tanaka, Exh. CJT-1T at 24:12-24:17.

agreeing in this rate case to provide the following energy burden data annually as a performance metric:

> Energy burden: Annual residential bill divided by area median income by census tract for all customers, comparing outcomes in Named and Non-named Communities. The number and percentage of customers experiencing high energy burden by census tract.[70]

However, these measures do not go far enough. First, the EBA does not provide an assessment of stratified energy burdens. Second, the EBA is also already a year and a half old;[71] regularly updated data will be important to continual monitoring of progress toward closing the excess energy burden gap.

Q: Please explain what you mean by an assessment of stratified bill burdens.

A: The assessment of energy burdens should extend beyond a simple yes or no toggle (*i.e.*, they are either bill burdened or not bill burdened). A more refined analysis would include a stratification of bill burdens. A natural gas-only stratification would include: (1) Affordable (= < 2%); (2) High Burdens (2% - 6%); (3) Very High (6% - 10%); and (4) Extreme Burdens (>10%).

Q: How should the bill burden assessment identify household income?

A: A robust evaluation should acknowledge and seek to ameliorate, to the extent possible, the inherent limits in reporting energy burden metrics based on median income levels. TEP recommends including at least two household income metrics: median income for the geographic area studied, and one or more indicators of low-income status, *e.g.*, the

[70] Siores, Exh. NCS-1T at 4:1, tbl.1.

[71] Exh. CJT-3 at 2.

census bureau's first quintile income and analysis of actual identified low-income energy burdens compared to the median.

Q: What geographic granularity should the assessment include?

A: The assessment should provide data by census tract.

Q: Should the assessment provide energy burden data for gas only?

A: No, the assessment should provide customer-level data to support findings regarding both gas-only and dual fuel energy burdens. NWN and Clark PUD both currently use the same consultant, Empower Dataworks, to create their EBAs. NWN should explore the opportunity to work with Clark PUD to modify their data sharing agreements and contracts with Empower Dataworks to allow Empower Dataworks to identify individual customer bills from NWN and Clark PUD. This would allow the next EBAs from NWN and Clark PUD to include customer-level data on burdens from both fuel sources. As a result, the EBA could present both single fuel and dual fuel energy burdens using actual customer data, producing an EBA with a more precise and complete dataset.

Q: How often should NWN perform this assessment?

A: TEP recommends that NWN perform an energy burden analysis at least every two years (biennially), to ensure that up-to-date data are always available. The usefulness of EBA data for timely and accurate assessments of affordability has a fixed shelf life. As rates, gas costs, customer base, and environmental factors fluctuate or escalate, so does affordability. A biennial burden assessment allows NWN to timely target its resources to relieve excess burdens as well as track affordability trends, *i.e.*, customer bill assistance needs, over time.

Q: Does TEP recommend that the Commission's order in this case require each element of the energy burden assessment you describe above?

A: No. TEP recommends that the Commission order NWN to perform a biennial energy burden analysis that includes an assessment of stratified energy burdens. To design the specifics of the assessment, the Commission should ask NWN to engage with its GREAT Advisory Group, where we can work through the details of exactly how to design the energy burden assessment. These conversations should address the exact stratification to use, the identification of incomes, the geographic granularity, and the appropriate timing.

Q: Please explain your second request—that NWN create a secure access portal to implement low-income programs.

A: NWN's current system for communicating customer information to the agencies (WAGAP and Clark PUD) that implement the low-income programs lacks essential functionality. The current system relies on back-and-forth emailing that is subject to delays and does not allow the agencies to directly access the customer information they need to enroll customers in bill assistance. By contrast, an access portal that permits the agencies to securely access relevant customer information and interact with customers' accounts on low-income program matters would improve the implementation and

collaboration potential of these programs. TEP expects that such a portal would improve the efficiency of the enrollment process for both the Company and agencies.

Q: Is there precedent for IOUs in Washington adopting such an access portal?

A: Yes. Puget Sound Energy, Cascade Natural Gas, Pacific Power, and Avista have all adopted a secure access portal with similar functionality to what TEP would like to explore working with NWN to develop.

Q: What should the access portal allow the agencies to do?

A: NWN should work with the GREAT Advisory Group to develop the portal's specific functionalities. The key elements of a robust access portal system are that it provides secure access to client data in "real time," allowing agencies to verify account status and process applications more efficiently and responsively to client needs. Additionally, it would enable agencies to directly enroll customers in utility programs and take related actions regarding customer accounts. The customer information to which the agencies would likely need access includes:

1. the current balance on an account;
2. the name on the account as well as any authorized users;
3. the billing usage history;
4. age of account;
5. any history of enrollment in other programs, such as the last time the customer received a benefit (like arrearage help);
6. the bill discount rate information for the account (including the discount tier, the enrollment date, and verification status); and
7. the account's dunning status.

Regarding taking actions concerning an account, the portal should allow the agencies to:

1. post bill assistance pledges;
2. enroll customers in BDR and arrearage forgiveness programs; and
3. flag "exempt" customers who are seeking assistance and should not be routed toward disconnection. (This would allow the agencies to lock a

customer's account so the customer does not receive a disconnection notice or collection actions.)

Q: When should NWN create and implement this access portal?

A: While TEP would prefer a more immediate timeline, we recognize that NWN has a long-term plan to replace its existing customer information system ("CIS").[72] NWN plans to replace its CIS by 2032.[73] The Commission should order NWN to incorporate development of a secure access portal into NWN's long-term CIS replacement project. Ensuring NWN creates the portal as part of this project is critical, because it will likely be a very long time before NWN again overhauls its CIS, and there is therefore a window of opportunity to include an access portal that would be missed if NWN were permitted to delay the portal longer. Additionally, it is likely more efficient to create a secure access portal while the entire CIS is being redesigned, rather than as an independent project. I thus request that the Commission order NWN to work with its GREAT Advisory Group to create a secure access portal as part of its planned CIS overhaul.

VI. The Commission should order Northwest Natural to reform certain aspects of its disconnection policies.

Q: What rules and procedures does NWN follow when determining whether to disconnect a customer?

A: NWN follows three sets of rules for determining whether to disconnect a customer for non-payment. First, NWN is subject to Washington's rules and regulations governing

[72] Fellon, Exh. BEF-1CT at 18:3-18:6.

[73] *Id.* at 19:4-19:5.

disconnection.[74] Second, NWN follows the disconnection rules in Rules 2, 4, and 5 of its Washington tariff.[75] Third, NWN implements internal policies and procedures that it uses to determine when it will disconnect a customer for nonpayment. These are outlined in internal documents, not NWN's tariff. Throughout this testimony, I will refer to these three categories collectively as NWN's "disconnection policies."

Q: Please describe NWN's disconnection timeline and process.

A: NWN uses an internal process to determine whether to disconnect a customer for non-payment. If a customer owes more than $150 in arrears and is more than 14 days past-due, NWN may send a disconnection notice. This notice is followed by additional communications that ultimately permit a customer to be disconnected as soon as 34 days after a bill is due.[76] NWN will make at least two attempts to contact a customer before disconnecting (as required under WAC 480-90-128). After a customer has been disconnected for non-payment, NWN may send this "bad debt" to a collection agency, which may report the bad debt to a credit bureau.[77]

Q: Please summarize your concerns with NWN's disconnection policies.

A: NWN's disconnection thresholds (in terms of time past-due and dollar amount owed) are too low. Additionally, NWN permits its collection agencies to report customer

[74] *See* WAC 480-90-128 (utilities must provide at least 3 days advance notice before disconnection); WAC 480-90-133 (utilities must make all reasonable efforts to reconnect within 24 hours after sufficient payment of past-due bill is made); WAC 480-90-138 (requiring utilities to offer payment arrangements).

[75] NWN Tariff WN U-6, https://www.nwnatural.com/about-us/rates-and-regulations/washington-tariff-book.

[76] Exh. SNS-3 at 1 (NWN Response to TEP DR 03).

[77] *Id.* at 4 (NWN Response to TEP DR 09).

information on disconnections to credit bureaus. NWN's disconnection thresholds, and its practice of allowing bill collection agencies to report bad debt to credit bureaus, are inequitable because they make it more likely customers will be disconnected for relatively minor non-payments and raise the risk that the financial impact of the disconnection will be magnified through a correlating reduction in credit score.

Q: Where do these concerns originate?

A: I have several years of professional experience working directly with disconnected households in King County seeking assistance to get their service restored, and thus have a firsthand frame of reference to the payment barriers and negative consequences of shut-offs for vulnerable, under-resourced households. Beyond this, my concerns continue to grow due to an ever-expanding body of research and literature that demonstrates how problematic utility disconnections are from an equity standpoint. The literature shows that low-income ratepayers who are disconnected for non-payment tend to be facing complex economic burdens,[78] and disconnections only exacerbate these problems, as utility debt increases these customers' financial stress, and going without heat is a serious health and safety risk. In assessing NWN's disconnection policies, the Commission should employ the principles of energy equity that form the equity lens the Commission applies in all public interest considerations.[79] In applying this lens, the Commission seeks to ensure that utility policy is "addressing historic underinvestment and exclusionary

[78] *See, e.g.*, Exh. SNS-14 at 5, tbl.2 & 3 (Callie Ginapp et al., *Exploring the Relationship Between Debt and Health After Incarceration: A Survey Study*, J. Urban Health (Feb. 2023) (hereafter "*Debt and Incarceration*")) (showing high prevalence of multiple debts as well as utility debts among formerly incarcerated individuals).

[79] Cascade 2021 GRC Order, ¶ 58.

policies and practices that have allowed inequity to flourish."[80] Regulated companies must assess whether proposed modifications to their practices correct or perpetuate inequities.[81]

NWN's low disconnection thresholds and its practice of allowing collection agencies to send customer information to credit bureaus are inequitable because the burdens of disconnections inordinately fall on marginalized populations.[82] People of color and low-income residents are disproportionately likely to have outstanding utility debt.[83] Formerly incarcerated people are especially likely to have utility debt.[84] Research consistently shows that people of color, low-income households, households with young children, and households residing in deficient or energy inefficiency housing conditions are more likely to experience energy insecurity and utility disconnections.[85]

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[80] *Id*. ¶ 57 (citing Executive Order 22-04: Implementing the Washington State Pro-Equity Anti-Racism (PEAR) Plan and Playbook).

[81] *Id*. ¶ 58.

[82] Exh. SNS-15 at 22-23 (Rocky Mountain Institute, Utility Disconnections Handbook (Aug. 2025)); Exh. SNS-16 at 9 (Diana Hernández & Jennifer Laird, *Surviving a Shut-Off: U.S. Households at Greatest Risk of Utility Disconnections and How They Cope*, 66 Am. Behavioral Scientist 00(0) (2022)).

[83] Exh. SNS-17 at 4 (Paul M. Ong et al., *Keeping the Stove On: COVID-19 and Utility Debt*, UCLA Luskin Center for Innovation (Nov. 2021)).

[84] Exh. SNS-14 at 5 (*Debt and Incarceration*).

[85] *WUTC v. Puget Sound Energy*, Dkts. UE/UG-220066/67, Exh. DK-1T at 12. Additionally, TEP and others have provided evidence of these inequitable impacts in the COVID-19 docket and the Credit and Collections Rulemaking, among others. *See, e.g.*, Dkt. U-200281, In the Matter of Response to the COVID-19 Pandemic, Joint Comments on Behalf of the Office of the Attorney General Public Counsel Unit, The Energy Project, NW Energy Coalition, Puget Sound Sage, Front & Centered, and Sierra Club, at 15 (Sept. 30, 2020) (presenting evidence showing that "[c]ommunities of color are disproportionately impacted by utility disconnections"); Dkt. U-210800, Second Comments of the Energy Project, at 2 (Aug. 19, 2022) (summarizing research showing that "even at comparable levels of income, Black households face disconnections at disproportionately high rates, relative to white households"); Dkt. U-210800, Comments of Joint
(footnote continued on next page)

Q: Explain in more detail your concerns with NWN's practice of allowing collections agencies to send customer disconnection information to credit bureaus.

A: NWN allows the two collections agencies it works with to report bad debt to credit bureaus.[86] This practice reinforces existing systemic barriers and perpetuates a cycle of poverty. Low-income customers and people of color are already more likely to have lower credit scores.[87] Further, credit reports are routinely pulled by prospective landlords, meaning that a negative credit report caused by utility debt can result in renters being unable to find housing.[88]

For these and similar reasons, Puget Sound Energy, Avista, and Cascade Natural Gas instructed the collection agencies they contract with not to report bad debt to the credit bureaus.[89] TEP asks NWN to do the same.

Advocates, at 1-5 (Oct. 17, 2022) (reviewing research on inequitable impacts of disconnections on communities of color); *id.* at 4 (citing an analysis of zip code level utility disconnection data in California finding that Black and Latinx households disproportionately experience utility shutoffs); Dkt. U-210800, Presentation Materials of David Konisky, at 11 (June 22, 2023) (presenting research showing that Black and Hispanic households experience disconnections at disproportionately high rates).

[86] Exh. SNS-3 at 4 (NWN Response to TEP DR 09).

[87] *See, e.g.*, Benet Wilson & Ashley Parks, *How Race Impacts Credit: The History and Effect on Lending Practices*, Bankrate (Feb. 19, 2025), https://www.bankrate.com/personal-finance/credit/does-race-affect-credit-score/; Caroline Ratcliffe & Steven Brown, *Credit Scores Perpetuate Racial Disparities, Even In America's Most Prosperous Cities*, Urban Institute (Nov. 20, 2017), https://www.urban.org/urban-wire/credit-scores-perpetuate-racial-disparities-even-americas-most-prosperous-cities.

[88] *See, e.g.,* RCW 59.18.257 (procedures landlords use for accessing credit reports).

[89] Dkt. U-210800, Credit and Collections Rulemaking, Comments of Puget Sound Energy at 1 (Sep. 26, 2023); Dkt. U-200281, WUTC Open Meeting March 24, 2022, Statements of Shawn Bonfield Representing Avista Corporation (noting that as a result of Avista's intervention, its contractor collections agencies "no longer report to credit bureaus on the customers we send to them."); Dkt. U-210800, Credit and Collections Rulemaking, Deposits, Fees, Payment Arrangements, and Customer Notice Workshop (September 9, 2023).

Q: Explain in more detail your concern with NWN's disconnection thresholds.

A: NWN currently sends a shut-off notice just 14 days after a bill is due. A customer can be disconnected as soon as 34 days after a bill is due.[90] This practice raises equity concerns because low-income customers struggling with significant energy burdens will find it particularly challenging to meet short payment timelines and have an increased likelihood of facing the destabilizing consequences of multiple shut-offs in succession. This makes the challenge of preventing disconnections more difficult for the kinds of customers who already face shutoffs disproportionately. NWN has presented no evidence that this timeline was adopted with equity in mind. A longer timeline would give low-income customers greater opportunity to resolve their arrears through payment or assistance, thus reducing the distributional equity concerns disconnections pose. To align with timelines the Commission has approved for other utilities,[91] NWN should not send a shut-off notice (or otherwise implicitly or explicitly threaten disconnection) to residential customers until their bills are at least 60 days past-due.

Also, NWN currently allows customers to be disconnected who owe as little as $150 in past-due utility bills.[92] This is slightly more than one month's average bill for low-income, high-burden customers, who pay an average of $1,380 annual in gas bills

[90] Exh. SNS-3 at 1 (NWN Response to TEP DR 03).

[91] *WUTC v. Puget Sound Energy*, Dkt. UE/UG-220066/67, Order 32/18, ¶ 56 (May 16, 2024) (requiring minimum 90 days past due); *WUTC v. Cascade Natural Gas Corp.*, Dkt. UG-240008, Order 05 Rejecting Tariff Sheets; Approving and Adopting Settlement with Conditions; Authorizing and Requiring Compliance Filing, ¶ 88 (Feb. 24, 2025) (approving raising threshold to 60 days past due).

[92] Exh. SNS-3 at 1 (NWN Response to TEP DR 03).

(averaging $115 per month).[93] That means a NWN customer risks disconnection for failing to pay one higher-than-average monthly bill. This puts low-income, energy-burdened customers at risk of disconnection quickly. A more equitable disconnection dollar threshold would be $300, which is just over 2.5 times the average monthly bill for a highly energy burdened customer in NWN's Washington service territory. This would allow energy-burdened customers more time to correct their arrearage before risking being shut off.

To clarify, TEP is not asking that NWN be restricted from communication and outreach to energy-insecure customers. Put simply, disconnection and the threat of disconnection must be treated less as a primary collections strategy and instead as a last resort due to the significant equity concerns and likelihood of harm to vulnerable households. NWN has not demonstrated that it considered equity and potential harm when adopting its current thresholds. The Commission should order NWN to increase the number of days a customer must be past-due to trigger disconnection procedures to 60 days and increase the disconnection dollar threshold to $300.

Q: Do you have any other specific concerns related to disconnections that you want the Commission and NWN to consider?

A: Yes. NWN should permanently remove fees and deposits that are currently waived under the settlement term sheet in the Commission's COVID-19 docket, U-200281.[94] These waived fees apply to all residential customers and include (1) late fees and deposits, (2)

[93] Exh. CJT-3 at 24.

[94] Dkt. 200281, Order 06 Amending Order 03; Exempting Gas and Electric Companies From WAC 480-100-113 and WAC 480-90-113, ¶ 18 (Mar. 29, 2022) (extending settlement term sheet waiving fees).

disconnection and reconnection fees, and (3) disconnection and reconnection visit fees.[95] NWN's fees and deposits in these categories are set forth in NWN's tariff.[96] This would implement the draft WAC 480-90-113 the Commission issued in the Credit and Collections rulemaking docket on August 28, 2023.[97] Even without those draft rules being effective, permanently removing fees and deposits from NWN's tariff is consistent with the current WAC 480-90-113, which does not require utilities to collect deposits.[98]

I recommend this because NWN's process for removing waived fees from customer accounts is manual and subject to human error. Reports provided to TEP by partner organizations and in the GREAT Advisory Group note that due to human error, some customers have been charged these waived fees.[99] To eliminate the need for NWN to have manual fee reversal processes (and associated human errors), NWN should remove the fees from its tariff and remove the automatic imposition of these fees from its billing software.

Q: Do you have any broader concerns for the Commission to consider with respect to NWN's disconnection policies?

[95] Dkt. 200281, Order 06, Appx. A – Fourth Revised Term Sheet, Section C – Fees, ¶¶ 1-3.

[96] *See* WN U-6, Schedule C (fees) and Rule 3 Sheet 3.1 (deposits). *Id.* Rule 4 Sheet 4.1.1, Schedule C and other rules discuss these fees and deposits.

[97] Dkt. U-210800, Notice of Opportunity to Provide Comments and Workshop Agenda, Attachment A (Aug. 28, 2023), https://apiproxy.utc.wa.gov/cases/GetDocument?docID=163&year=2021&docketNumber=210800. The relevant section is WAC 480-90-113(1), which, as the draft amendment provides, would prohibit utilities from collecting deposits from residential customers.

[98] WAC 480-90-113 ("gas utility may collect a deposit . . .").

[99] NWN reversed fees after the error was brought to the Company's attention.

A: Yes. NWN has not performed a full equity review of its disconnection policies. This means that the equity implications of NWN's current policies are not well-understood. My recommendations today are based on the limited information available regarding NWN's internal policies, and there is no indication NWN tracks how its disconnections impact different customer demographic groups. The Commission should order NWN to perform such a review in consultation with its GREAT Advisory Group and Community & Equity Advisory Group ("CEAG").[100]

Q: Why should NWN conduct an equity review of its disconnection policies?

A: Mandating a robust equity review of the policies in consultation with their advisory groups will improve the policymaking process. By working to apply an equity lens to the full suite of NWN's disconnection practices, NWN can proactively reform inequitable elements of its disconnection policies beyond the changes I advocated for above.

Q: How can the Commission ensure that NWN conducts a robust equity review?

A: TEP recommends the Commission order NWN to proceed in two steps after developing new policies according to this testimony:

1) By September 1, 2026, NWN must present its new disconnection for nonpayment policy and procedures to a meeting of its CEAG and GREAT Advisory Group and solicit feedback on the equity impacts of its policy and procedures.

2) By February 1, 2027, NWN must incorporate the feedback it receives and make a subsequent filing (pursuant to WAC 480-07-885) with new disconnection policies and procedures. The subsequent filing will discuss any feedback received which NWN did not incorporate and the reasons why it did not incorporate that feedback.

[100] *See* Tanaka, Exh. CJT-1T at 33:10-33:21 (overview of NWN's equity advisory group).

These steps promote accountability, collaboration, and timely revisions, and ensure an orderly course of action for reviewing NWN's disconnection policies.

VII. The Commission should ensure Northwest Natural develops and implements a language access plan.

Q: What steps has NWN taken to serve customers who speak a primary language other than English?

A: NWN has recently taken several good first steps to improve its language access services. NWN provides customers with bill discount program information in the top five non-English languages spoken within its service territory.[101] NWN also lets CEAG members review and give feedback on customer written communication materials on topics like bill discount programs, arrearage management, weatherization, and energy efficiency.[102] Additionally, NWN offers translation services on request, translates written materials into multiple languages with help from a nonprofit focused on immigrant and refugee populations' needs, writes many of its customer communications in plain language, and has plans to translate its customer website into the top five non-English languages in its territory.[103] TEP appreciates these efforts.

Q: Can NWN improve its language services?

A: Yes—significant gaps in NWN's language access services remain. First, NWN does not track language preferences at the individual customer level.[104] This indicates that NWN

[101] Beck, Exh. CAB-1T at 6:12-6:15.

[102] *Id.* at 7:1-7:9; Exh. SNS-2 at 2 (NWN Response to TEP DR 02).

[103] Beck, Exh. CAB-1T at 8:4-9:7.

[104] Exh. SNS-2 at 1 (NWN Response to TEP DR 01).

has not identified—and does not know—which of its customers would prefer services in a language other than English. Tracking individual customer preferences would allow NWN to tailor communications to the correct language for each customer, rather than relying on on-the-spot translation options and high-level data concerning the top languages spoken in NWN's service territory.

Second, NWN does not yet have a comprehensive plan to identify gaps in its language access services. Without one, NWN risks continuing to underserve its non-English preferring customers.

Q: Does TEP have any recommendations regarding language access?

A: Yes. The Commission should order NWN to track individual customers' language preferences. Additionally, the Commission should order NWN to develop a comprehensive language access plan to proactively meet its customers' language needs. NWN has already indicated it is considering adopting such a plan by the end of 2026.[105]

Q: What does a language access plan include?

A: Language access plans are policies that set out the language needs and preferences of an organization's clients and partners and the steps the organization will take to improve language access and multilingual services.[106] These plans typically include several primary components, including: (1) a comprehensive needs assessment; (2) identification and implementation of improvements to language services; (3) actions to enhance awareness among clients and customers regarding the organization's available language

[105] Beck, Exh. CAB-1T at 11:8.

[106] United Language Group, *Guide to Developing a Language Access Plan*, https://www.unitedlanguagegroup.com/resources/developing-a-language-access-plan.

services; (4) training for employees on language access needs, policies, and programs; and (5) a framework and metrics to evaluate the success of the language access plan.[107]

Q: Why should NWN adopt a language access plan?

A: Language access plans serve several important functions. The plan will (1) prompt a comprehensive evaluation of customer language preferences and existing services, identifying deficiencies and room for improvement; (2) improve customer relations; (3) provide more equitable access to NWN programs targeted toward low-income customers, including weatherization and energy assistance programs; and (4) help NWN learn best practices for multilingual services. In general, the language access plan promotes reflection and accountability by giving NWN and other stakeholders clear criteria to evaluate NWN's language access efforts.

Q: Has the Commission supported the adoption of utility language access plans before?

A: Yes. The Commission has explained that "[a]ccessibility and the development of language access plans are an important consideration for all investor-owned utilities."[108] The Commission has stated support for NWN increasing its language access before; it has also done so in cases concerning Puget Sound Energy, Cascade Natural Gas, and

[107] *Id.*

[108] *WUTC v. Puget Sound Energy*, Dkts. UE/UG-220066/67, Order 32/18, ¶ 57 (May 16, 2024).

PacifiCorp.[109] Cascade Natural Gas, Puget Sound Energy, and PacifiCorp have or are in the process of developing language access plans.[110]

Q: How should the Commission ensure that NWN develops and implements an effective language access plan?

A: The Commission should direct NWN to take five steps to develop a language access plan.

First, by September 1, 2026, NWN should complete an evaluation of language barriers to accessing low-income programs in a draft language access plan. Comprehensively evaluating language barriers to low-income programs will show how NWN can cost-effectively meet customer language access needs.

Second, also by September 1, 2026, NWN should provide its GREAT Advisory Group and CEAG with a draft language access plan for its low-income programs and request feedback on the plan. Soliciting feedback on a draft plan enables collaboration and early identification of oversights. A formal feedback mechanism will allow the advisory groups to shape NWN's approach and identify areas for improvement.

Third, by December 31, 2026, NWN should incorporate feedback it receives, discuss any feedback received on the draft not incorporated into the final, state the reason NWN did not incorporate the feedback into the final, and make a subsequent filing (pursuant to WAC 480-07-885) with a final language access plan for its low-income programs. This process will facilitate accountability and transparent decision-making.

[109] *Id.*; *WUTC v. PacifiCorp*, Dkt. UE-230172, Order 08, ¶ 104 (Mar. 19, 2024); *WUTC v. NWN*, UG-200994, Order 05, ¶ 45 n.22 (Oct. 21, 2021); *WUTC v. Cascade Natural Gas Corp.*, Dkt. UG-240008, Order 05, ¶ 99 (Feb. 24, 2025).

[110] *WUTC v. Puget Sound Energy*, Dkts. UE/UG-240004/05, Final Order 09/07, ¶ 185 (Jan. 15, 2025); *WUTC v. PacifiCorp*, Dkt. UE-230172, Final Order 08, ¶ 22 (Mar. 19, 2024); *WUTC v. Cascade Natural Gas Corp.*, Dkt. UG-240008, Order 05, ¶ 99 (Feb. 24, 2025).

Rather than requiring the Commission or interested parties to undertake the cumbersome process of determining what feedback was integrated or rejected, NWN will clearly explain the choices it makes.

Fourth, NWN should annually report on its progress toward accomplishing the language access plan in its annual energy assistance report to the Commission. Regular reporting serves transparency and informs the Commission and interested parties about NWN's efforts. The annual report is an existing opportunity NWN can use to provide updates.

Finally, NWN should maintain and revise the language access plan as needed, with approval and feedback from the GREAT Advisory Group and the CEAG. As NWN implements its language access plan, it will succeed in some efforts and discover new barriers to language access programming. Requiring regular revision of the plan will ensure that NWN learns from its efforts, meets new and changing needs of its customers, and collaborates with its advisory groups moving forward.

To summarize, the Commission should direct NWN to take five steps:

1. By September 1, 2026, evaluate language barriers to accessing low-income programs in a draft language access plan.
2. By September 1, 2026, provide its GREAT Advisory Group and CEAG with a draft language access plan for its low-income programs and request feedback on the plan.
3. By December 31, 2026, incorporate feedback it receives, discuss any feedback received on the draft not incorporated into the final, state the reason NWN did not incorporate the feedback into the final, and make a subsequent filing (pursuant to WAC 480-07-885) with a final language access plan for its low-income program.
4. Report on its progress toward accomplishing the language access plan in its annual energy assistance report to the Commission, and
5. Maintain and revise the language access plan as needed, with approval and feedback from the advisory groups.

VIII. The Commission should not allow Northwest Natural to recover fees and costs which the Commission and the Governor prohibited Northwest Natural from charging during the COVID-19 pandemic.

Q: What costs is NWN seeking to recover related to its COVID-19 deferral?

A: NWN Witness Kyle Walker states that NWN is seeking a total of approximately $1.4 million in COVID-19 deferral expenses.[111] NWN's costs fall into four categories:[112]

a. Direct costs;

b. Bad debt expense accrued above baseline;

c. Late payment fees not assessed (including forecasted amounts through Q2 2026[113]); and

d. COVID-19 bill payment assistance program costs.

NWN is not proposing to recover interest with the COVID-19 deferral costs.[114]

Q: What is your opinion on NWN's proposal not to recover interest?

A: I agree with this proposal.

Q: What is your opinion on NWN's proposal to recover costs from late payment fees not yet assessed?

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[111] Walker, Exh. KTW-1T at 52:17.

[112] *In the Matter of the Petition of NWN for an Order Approving Deferral of Costs Associated with the COVID-19 Public Health Emergency*, Dkt. U-200264, NWN's Third Quarter 2025 COVID-19 Report Required by Order 01 (Oct. 30, 2025).

[113] *See* Exh. SNS-4 (NWN Response to TEP DR 19) (discussing difference between $1.4 million and $1.31 million stated in most recent NWN "quarterly COVID report" in Commission docket U-200264).

[114] *Id.*

A: The Commission should not allow NWN to recover these costs from customers. The fundamental question is whether it is appropriate for NWN to charge its customers now for late payment fees that were never assessed during the pandemic. NWN was prohibited from charging these fees during the pandemic via proclamations of the Governor of Washington and by Commission orders. NWN thus had no right to recover those fees and never assessed them. It would be unfair to now let NWN indirectly charge those fees by including them in its revenue requirement, which will be paid for from the pockets of NWN's customers via higher rates going forward. NWN's proposal would make thousands of customers for whom charges were waived nonetheless pay an apportioned late fee, a result directly contrary to the Governor's proclamation. Plus, customers who would not even have accrued late fees during the pandemic would have to bear some of the costs. This is an inequitable proposal.

Public Counsel and The Energy Project raised questions about the legality of recovering this category of COVID-19 costs at the time deferral of the costs was requested.[115] In its Order approving the deferral, the Commission explicitly stated that allowing the deferral of uncollected fees "in no way guarantees their later recovery, and the Commission can revisit this issue at the time it performs its prudence review."[116] The Commission should decline to allow these costs to now be included in rates.

[115] *See* Dkt. UG-200264, Petition of Northwest Natural Gas Co. for an Accounting Order Associated with COVID-19 Public Health Emergency, Joint Response of The Energy Project and Public Counsel, at 14-18 (Nov. 11, 2020), https://apiproxy.utc.wa.gov/cases/GetDocument?docID=75&year=2020&docketNumber=200479.

[116] Dkt. UG-200264, Order 01 Granting Accounting Petition Subject to Conditions, ¶ 23 (Dec. 10, 2020).

Q: How much is NWN seeking to recover in uncharged late fees?

A: NWN is seeking $383,971 in late fees counted through Q3 2025, plus about $74,600 in late fee activity forecast through Q2 2026.[117] This totals approximately $459,000—over one third of the total NWN COVID-19 deferral recovery request.

Q: Next, what is your opinion of NWN's proposal to recover other direct costs?

A: In this cost category, NWN is asking its customers to pay the company's costs for things like personal protective equipment, cleaning supplies and services, contact tracing, medical testing, financing costs, information technology updates, and equipment for remote work options.[118] Many of these types of costs were incurred by nearly every individual household in Washington. NWN's customers had no ability to shift their comparable costs onto someone else; the costs were a part of coping with the realities of the pandemic. NWN admits that its only consideration of "equity" regarding its decision to seek recovery of its COVID deferral was the notion that it would be better to make current customers pay for these costs than future customers.[119] It is fundamentally inequitable for NWN to force its own customers to bear NWN's PPE, cleaning, remote work, and COVID testing costs on top of their own costs.

Q: Please summarize your recommendation concerning COVID deferred costs.

A: The Commission should allow NWN to recover bad debt expenses above baseline but should refuse to allow NWN to recover uncharged fees and direct costs.

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[117] Dkt. U-200264, NWN Third Quarter 2025 COVID-19 Report Required by Order 01 (Oct. 30, 2025); Exh. SNS-4 at 1 (NWN Response to TEP DR 19).

[118] *See* Dkt. U-200264, Amendment to Petition of NWN, ¶ 10 (Nov. 5, 2020).

[119] Exh. SNS-4 at 2 (NWN Response to TEP DR 20).

IX. The Commission should order Northwest Natural to revise and add to its proposed Performance-Based Ratemaking metrics and to post them on its public website.

Q: Please explain the metrics NWN proposes which TEP seeks to revise and its reasoning regarding those revisions.

A: TEP recommends revising two metrics NWN proposes and rejecting NWN's proposal not to track the workforce and supplier diversity metrics established in the Policy Statement. First, NWN proposes to report a metric titled Arrearages as "[n]umber of customers in arrears by period and total amount of arrearages by month, by class, measured by census tract to include 30+, 60+, and 90+ days in arrears."[120] TEP supports reporting this metric but suggests revising the metric to clarify how each band of customers in arrears is calculated. At present, it is unclear whether a customer that is 61 days late would be reported in both the 30 day and 60 day data or only the 60 day data. The Commission has previously suggested, and TEP has previously supported, calculating at the highest interval, so the customer 61 days late would only be reported in 60+ data.[121] TEP recommends including metric language that adopts that mode of calculation.

NWN also proposes measuring Utility Assistance Program Effectiveness as "[o]n an annual basis, utility customer-funded assistance funds dispersed divided by total available customer-funded assistance received, as well as the percentage of estimated low-income needs met with dispersed funds."[122] First, it is noteworthy that NWN's metrics are based on the policy docket, and the Commission appears primed to remove the first

[120] Siores, Exh. NCS-1T at 4, tbl.1.

[121] Dkt. U-210590, The Energy Project's Eighth Comments on Performance-Based Regulation (PBR) and the UTC's Interim Policy Statement at 6 (May 17, 2024).

[122] Siores, Exh. NCS-1T at 4, tbl.1.

portion of this metric in that proceeding.[123] TEP did not object to that proposal; with the advent of Bill Discount Programs, low-income assistance is shifting from being based on a fixed amount of funding to one in which trackers provide cost recovery based on enrollment and demand. Accordingly, measuring outlays is no longer the best measurement of program effectiveness.[124] TEP would similarly not object to revising the metric here if the Commission formally removes the first portion of the metric in the policy docket.

For the remainder of the metric, NWN needs to further define the term "estimated low-income need." Evaluating low-income program effectiveness will depend on the purpose of specific programs. In its most recent PBR update, the Commission indicated that utilities could use any of the following methodologies for this data: (a) Section 120 reporting, (b) Energy Burden Assessment data completed within the past two years, or (c) Methodology established with the low-income advisory group.[125] NWN should establish which source of data it will use for this metric in this proceeding. TEP encourages NWN to use the EBA data option.

In addition, NWN should revise the title of the metric. Despite its current title, the metric is a less useful indicator of utility assistance program effectiveness than the number and percentage of estimated low-income customers enrolled in bill assistance programs. While TEP still views the proposed metric as valuable, future analysis will be

[123] *Id.* at 3:16-18; Dkt. U-210590, Notice of Opportunity to Comment, Appendix A at 4 (Dec. 11, 2025).

[124] Dkt. U-210590, Twelfth Comments of the Energy Project's on Performance-Based Regulation in Washington at 2 (Nov. 12, 2025).

[125] Dkt. U-210590, Notice of Opportunity to Comment, Appendix A at 4 (Dec. 11, 2025).

better served by clarifying what the metric is truly tracking. TEP recommends changing the title of the metric to "Low-income need spending" to better match the data the metric is reporting.

Q: Should NWN report any additional metrics beyond those in its proposal?

A: In addition to refining the above metrics, NWN should report workforce and supplier diversity metrics.[126] Workforce and supplier diversity metrics are already part of the Commission's Policy Statement and will already be part of utility performance metric reporting.[127] TEP opposes specifically carving these diversity figures out of NWN's otherwise consistent effort to report Commission-endorsed Policy Statement metrics. Refining Commission-endorsed metrics may be warranted in some circumstances, but TEP sees no value in enabling the Company to reject metrics the Commission established in its Policy Statement.

Finally, TEP supports including customer participation in assistance programs. NWN proposes to report "[t]he number and percentage of estimated low-income customers who participate in one or more customer-funded energy assistance programs that actively lowers energy burden, both aggregated and by census tract; and separately the number and percentage of estimated low-income population enrolled in a utility bill discount program and total amount of discount applied annually."[128] As noted above, TEP applauds NWN for its progress serving a large portion of the customers in its service

[126] Siores, Exh. NCS-1T at 5:4-7:2.

[127] Dkt. U-210590, Notice of Opportunity to Comment, Appendix A at 6 (Dec. 11, 2025).

[128] Siores, Exh. NCS-1T at 5, tbl.1.

territory; with the current program design, this is the most important metric to the communities TEP works with.

Q: Does TEP propose NWN take any other additional actions related to Performance-Based Ratemaking?

A: Yes. NWN should post its performance metrics in an easily accessible area of its website. Witness Siores states that NWN will provide its data as an appendix to its Commission Basis Report.[129] Performance metrics are an important source of information for both advocates and the public to assess utility performance. Solely providing these data in the Commission Basis Report hinders the public's ability to easily view and access these valuable metrics. NWN should therefore provide these data on NWN's website in an easily accessible fashion.

X. The Commission should ensure Northwest Natural's proposed Thermal Energy Network pilot project will serve low-income housing when considering the equity implications of the proposed rate base merger to pay for the project.

Q: Please summarize NWN's TEN pilot project.

A: TENs are systems that distribute noncombustible fluids (usually water) through pipes to transfer heat into and out of buildings using non-combustion energy sources, such as geothermal electric heat pumps.[130] NWN is planning to develop a TEN in downtown Vancouver, Washington, and to recover the costs of building and operating the TEN primarily from natural gas customers.[131] NWN's plans are not fully finalized, but as

[129] *Id.* at 10:12-15.

[130] *See* RCW 80.04.010(31)-(33).

[131] Braun, Exh. HJB-1CT at 8:8-8:15, 25:22-26:6; RCW 80.28.450(2); RCW 80.28.480(1).

currently planned, the TEN would supply all heating, cooling, and hot water services to three new buildings and to City Hall, all within Vancouver's Waterfront Gateway district. The new buildings would include more than 300 units of housing and about 30,000 square feet of retail space.[132]

Q: What is the legal background relevant to NWN's proposal?

A: A state law enacted in 2024 encourages utilities to develop TENs to support the state's climate goals.[133] Under the law, an IOU proposing to develop a TEN pilot program must submit its proposal to the Commission for approval.[134] Criteria for approval include labor, reliability, safety, greenhouse gas reduction, heating functionality, as well as several equity-based factors.[135] These equity factors include: (1) the percent of low-income customers the TEN would serve; (2) whether it creates public health benefits in disproportionately burdened and disadvantaged communities described in the Washington State Department of Health Environmental Health Disparities Map; (2) whether it increases affordability of thermal energy options; (3) whether it furthers the climate justice mandates of chapter 70A.02 RCW; and (4) whether it advances financial and technical approaches to equitable and affordable building electrification.[136]

Further, if an IOU intends (as NWN does here) to recover TEN costs from natural gas customers not served by the TEN, it must file a request for a rate base merger.[137] That

[132] Braun, Exh. HJB-1CT at 8:8-8:15.

[133] H.B. 2131 (2024) (codified at RCW 80.28.450-480; RCW 43.31.033).

[134] RCW 80.28.460.

[135] *Id.*

[136] RCW 80.28.460(a), (e), (g)-(h).

[137] RCW 80.28.450(2).

request is what NWN is filing in this rate case. The Commission will only approve the rate base merger NWN proposes if it finds it to be "in the public interest."[138]

Q: What does NWN propose in this rate case regarding cost recovery for its TEN project?

A: In order to recover the cost of its TEN pilot project, NWN seeks a rate base merger as provided for in RCW 80.28.480, because NWN states it cannot feasibly obtain the full expected project cost from the TEN customers, i.e., the City (City Hall) or the commercial building tenants (the housing and business units).[139]

Q: What are TEP's concerns regarding this proposal to recover the costs of the TEN from natural gas customers?

A: Because of uncertainties about the customers the TEN would serve and the funding sources for the project, TEP has concerns about the project's ability to provide tangible benefits to low-income and vulnerable communities and the cost burden it would add to natural gas ratepayers' bills. As I will explain further, TEP cannot currently take a position on the project given these uncertainties, but urges the Commission to highly prioritize equity considerations in determining whether to approve NWN's proposed rate base merger.

TEP recognizes that the Commission's decision in this rate case only technically concerns the "public interest" determination regarding the rate base merger NWN is seeking for its project. However, given that the Commission is still reviewing the project's cost assessment in docket UG-250458, the equity criteria in RCW 80.28.460 are

[138] RCW 80.28.480(1).

[139] Braun, Exh. HJB-1CT at 25:22-26:6.

relevant to the Commission's ongoing review of the proposal. Furthermore, the Commission must apply an "equity lens" to the public interest determination it will make regarding NWN's proposed rate base merger.[140]

NWN has argued the TEN's mere location in a low-income census tract (042400), which has high scores for environmental health disparities, social vulnerability, and lead exposure risk among other things, promotes equity.[141] However, in order to actually promote equity, the project needs to provide benefits to the vulnerable communities within that census tract. TEP does not see how the TEN would create direct public health benefits (RCW 80.28.460(e)) or affordability (RCW 80.28.460(g)), because the project would not remove a source of pollution, and any affordability gained through the TEN's energy efficiency could be outstripped by the project costs to customers. This includes natural gas customers, who will have to bear the costs of the project without benefitting from the TEN.

Q: What are the key uncertainties about the TEN proposal?

A: Chiefly, it is still unclear whether the TEN will indeed serve low-income customers. Additionally, given that the project design is not fully finalized and the costs natural gas customers might bear are subject to still-pending grant funding, the financial impact of the project is not clear.

[140] RCW 80.28.480(1); *see* RCW 80.28.425(1) (Commission may consider equity and other factors in determining the public interest); *see* Cascade 2021 GRC Order, ¶ 58 ("So that the Commission's decisions do not continue to contribute to ongoing systemic harms, we must apply an equity lens in all public interest considerations going forward.").

[141] Braun, Exh. HJB-1CT at 11:18-12:7.

Regarding serving low-income housing, NWN's plans appear to have changed at least twice so far during the course of project development, and TEP is concerned that they may change again. Initially, the TEN was planned to connect to an additional new building that would have consisted of low-income housing units, but that building is no longer part of the plan.[142] NWN's testimony about the TEN described it as only serving municipal government, business, and multi-family market rate housing.[143] However, more recently, NWN stated in a response to a Commission data request that the developer of the planned multi-family housing now intends to rent out 50% of the units of both buildings containing housing to low-income households (at or below 80% AMI).[144] The prospect that the TEN would be connected to low-income housing units helps with the equity considerations the Commission must consider—especially RCW 80.28.460(a) (percent of low-income customers served). However, TEP cannot be sure these current plans will not change again, given that NWN has already gone back and forth on this. Since NWN has not provided definitive information showing the amount of low-income housing, if any, the TEN would serve, TEP cannot take a position regarding the equity impacts of the project. Serving low-income housing should be a key factor in the Commission's consideration of the proposal.

Second, TEP is concerned about the costs that low-income natural gas ratepayers who would not be connected to the TEN will shoulder to support the project. Even if the TEN serves some low-income customers, the proposed rate base merger represents an

[142] *Id.* at 8:12, n.6.

[143] *Id.* at 8:8-8:15.

[144] NWN Response to WUTC DR 123.

added cost burden to all NWN's gas customers, including low-income customers. NWN seeks to recover $1.3 million from gas customers in the first year of the TEN's operation.[145] In response to a TEP data request, NWN estimated that its revenue requirement for the TEN would, in the first year of service, raise some residential gas customers' average monthly bills by as much as 10%.[146] NWN also projected that natural gas customers would continue to pay for the project throughout its useful life.[147] However, it is unclear how much grant funding NWN will ultimately have to reduce these costs. Such information would be necessary for TEP to understand the full impact of the project.

TEP understands NWN initially planned this project to be funded largely through $25 million available in Department of Commerce grant funding, which has since dwindled to $4.8 million.[148] Even if NWN receives $2.4 million (half the money available for grants across the entire state), gas customers would still pay millions, representing virtually all of the project's capital costs.[149] TEP understands the unavailability of sufficient grant funding has impacted this project, but is concerned about

[145] Braun, Exh. HJB-1CT at 29:23.

[146] Exh. SNS-6 (NWN Response to TEP DR 30). Based on the information NWN provided, bill impacts would be different depending on customers' rate schedule. By NWN's estimate, Schedule 1 Residential customers would see an average monthly bill increase of $2.90 as a result of the rate base merger in the first year of service, representing a 10.3% increase. Schedule 2 Residential customers would see a $0.84 increase, a 1.2% change. *Id.*

[147] *Id.*

[148] Braun, Exh. HJB-1CT at 24:16-24:23.

[149] *Id.* at 30:1-30:4. The estimated annual O&M costs are $61,000. *Id.* at 24:3; this is approximately equal to the $86,000 NWN plans to charge TEN customers annually for service. *Id.* at 26:8-26:12.

the distributional equity outcome of making natural gas customers shoulder the cost of a project they will not benefit from.

Q: What does TEP recommend to the Commission at this stage regarding NWN's proposed TEN?

A: As I have discussed, neither TEP nor the Commission can fully analyze the equity impacts of the proposal without further information regarding the costs of the project and how it would directly benefit low-income utility customers. This prevents a robust analysis of the proposed rate base merger and the project as a whole, because equity factors are prominent in the statute authorizing TENs and are a key part of the Commission's rate base merger public-interest determination in this rate case. The Commission should give great weight to the equity factors outlined in the statute, especially considering that most of the project would be funded by NWN's gas customers. Without additional information about costs, grants, and equity impacts, TEP cannot support the proposal.

XI. Conclusion

Q: What does TEP propose concerning rate design?

A: The Commission should reject NWN's proposed fixed charge increase for residential customers. If the Commission allows any fixed charge increase, it should limit the increase to $0.15-0.25 per year.

Q: What does TEP propose concerning ROE?

A: The Commission should reject NWN's proposed ROE increase. The Commission should give great weight to its consideration of the equity impacts of high ROEs and to the proposals of the non-company parties on this subject.

Q: What does TEP propose concerning low-income programs and energy burden assessment?

A: The Commission should order NWN to perform an energy burden assessment every two years going forward, including a stratified energy burden analysis that includes single and dual fuel burdens. The commission should also order NWN to work with its GREAT Advisory Group to develop a secure customer information access portal for community action agencies (WAGAP and Clark PUD) to implement NWN's low-income programs.

Q: What does TEP propose concerning disconnections?

A: 1. The Commission should order NWN to raise its disconnection thresholds to $300 and 60 days past-due.

2. The Commission should order NWN to modify its contracts with its collections agencies to prohibit them from sending customer information to credit bureaus.

3. The Commission should order NWN to conduct a robust equity review of its disconnection policies in consultation with the GREAT Advisory Group and the CEAG and to meet the following deadlines:

a. By September 1, 2026, present its new disconnection for nonpayment policy and procedures to a meeting of its CEAG and GREAT Advisory Group and solicit feedback on the equity impacts of its policy and procedures.

b. By February 1, 2027, incorporate the feedback it receives and make a subsequent filing (pursuant to WAC 480-07-885) with new disconnection policies and procedures. The subsequent filing will discuss any feedback received which NWN did not incorporate and the reasons why it did not incorporate that feedback.

Q: What does TEP propose concerning language access?

A: The Commission should direct NWN to take five steps:

1. By September 1, 2026, evaluate language barriers to accessing low-income programs in a draft language access plan.

2. By September 1, 2026, provide its GREAT Advisory Group and CEAG with a draft language access plan for its low-income programs and request feedback on the plan.
3. By December 31, 2026, incorporate feedback it receives, discuss any feedback received on the draft not incorporated into the final, state the reason NWN did not incorporate the feedback into the final, and make a subsequent filing (pursuant to WAC 480-07-885) with a final language access plan for its low-income program.
4. Report on its progress toward accomplishing the language access plan in its annual energy assistance report to the Commission, and
5. Maintain and revise the language access plan as needed, with approval and feedback from the advisory groups.

Q: What does TEP propose concerning COVID-19 costs and policies?

A: The Commission should decline to allow NWN to recover uncharged fees and direct costs related to the COVID-19 pandemic, but should allow NWN to recover bad debt expenses.

Q: What does TEP propose concerning performance-based ratemaking?

A: The Commission should order NWN to revise its Arrearages and Utility Assistance Program Effectiveness metrics, and to report workforce and supplier diversity metrics. The Commission should also order NWN to post its metric reports on its public-facing website.

Q: What does TEP propose concerning NWN's TEN project?

A: TEP cannot support the TEN pilot project at this time, given that key information regarding project costs and whether it would serve low-income customers is still not finalized. TEP urges the Commission to give great weight to the equity prong of its analysis of the rate base merger NWN proposes in this case to pay for the project.

Q: Does this conclude your testimony?

A: Yes, it does.

February 24, 2026
Public Utility Commission of Oregon
201 High St. SE, Suite 100
Salem, Oregon 97301-3398

Re: AR 671/UM 2211 - Energy Justice Advocate Comments for additional metrics and reporting associated with evaluating Division 21 protections

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Following Staff's request for comments related to tracking customer outcomes and utility compliance with the updated disconnection protections in Division 21 rules per AR 671, Oregon Citizens' Utility Board, Oregon Just Transition Alliance, Verde and Community Energy Project, collectively "the Energy Justice Advocates", offer the following:

In AR 671, Energy Justice Advocates requested the Commission ensure there were metrics put into place for accountability and compliance for utilities, regarding the implementation of updated Division 21 Rules. This was in response to Staff's desire to have reporting requirements to accompany the updated rules, which we also support.[1] In our September 23, 2025 comments we stated the following:

> *"We support Staff's suggestion that this reporting be an annual supplement to existing Energy Burden Metric Reporting (EBMR). However, we encourage Staff to be clear in its final proposal to the Commission, that this reporting is also about understanding utility compliance with these rules, in addition to customer impacts from these rules.* ***As we mentioned in prior comments, we do have concerns about compliance due to previous misunderstandings and different interpretations of both winter and summer temporary rules. Regardless of this, ensuring compliance is a very important aspect of protecting customers.****"*

It very recently came to light, via public reporting in Docket RO 16[2] - the Energy Burden Metric Reporting docket - that NW Natural, Oregon's largest gas utility, did not actually implement its temporary winter 2025

[1] Docket No. AR 671 *Energy Justice Advocates' Comments on Staff's v5 Proposal,* Sep 23, 2025: https://edocs.puc.state.or.us/efdocs/HAC/ar671hac340076036.pdf at 16.
[2] Docket No. RO 16 *NW Natural's Energy Burden Metric Report for the 4Q 2025*, Jan 29, 2026: https://edocs.puc.state.or.us/efdocs/HAQ/ro16haq343430037.pdf at 4.

disconnection moratorium. NW Natural promised legislators, the PUC, advocates and the wider Oregon community, to activate a disconnection ban for its customers enrolled in the Company's Bill Discount Program (BDP) starting at least on November 12th through January 1, 2026.

This scandal unfortunately further validates advocates' concerns about utility compliance and accountability, and begs the question on the need for Commission issued penalties for failure to adhere to the Division 21 rules and other rules by Commission order.

Lastly, it is important to raise that compliance is additionally important for community trust - not just with customers and their utilities, but with customers and community organizations that work to give impacted communities up-to-date and accurate information about their rights as it relates to energy utilities. NW Natural's actions have put our reputations with communities at risk as well. **As it is our job as advocates to continue to not only fight for stronger protections, but to ensure these protections are being followed by utilities.**

We request (1) the following items be considered for utility reporting, acknowledging there may be other important metrics we have not yet considered, (2) and additionally ask that Staff and the Commission are thoughtful about what other *compliance level* reporting will be necessary going forward, (3) including what tools for penalties are applicable to non-compliance in Division 21 and adjacent Orders, policies and promises:

- Report the dates where moratoriums were in effect within utility territories. Currently, in RO 16 reporting, moratoriums are only reported by utilities as the number of days they were in effect by month;[3]
- Count of non-payment disconnections (day before severe weather) - see RO 18 reporting;
- Count of non-payment disconnections (two days after severe weather) - see RO 18 reporting (ensure this includes wildfire displacement rules);
- Count of how many customers are calling to reconnect during qualifying extreme weather moratorium periods (ensure this includes wildfire displacement rules in 0406) and tracking this by customer type

[3] Docket No. RO 16 ELECTRIC AND GAS UTILITIES ENERGY BURDEN METRICS REPORT PURSUANT TO OAR 860-021-0408: https://apps.puc.state.or.us/edockets/docket.asp?DocketID=24721

(i.e. on a bill discount program, a medical certificate, or N/A) - see RO 18 reporting;
- Count of how many customers remain disconnected during a qualifying severe weather event and tracking this by customer type;
- By bill discount program tier, for medical certificate customers, and all other residential customers, how much it costs to reconnect, including how much is fees vs bill balance - see RO 18 reporting;[4]
- By count, how many households are calling the utility inquiring about a past due bill, disconnection, and inability to pay - more specifically, for example, how many conversations are CSRs having where Division 21 rules are explicitly discussed/asked about;
- Policy audit reporting where utilities need to provide documentation of their adherence to policies, such as copies of disconnection notices, door hangers, redacted call log transcripts, CSR training materials, and any and all materials utilities send to agencies, etc. - these could be included in the annual EBMR supplement filing;

Relatedly, we have a few questions related to compliance given recent updates and changes to Division 21 rules, where compliance reporting that provides customer copies of utility-provided materials would be warranted. These are examples where utility provided examples of customer materials help to ensure compliance and shared understanding across stakeholders and customers:

- Do disconnection notices also alert customers to their protections under OAR 860-021-0407(5)(a) and OAR 860-021-0406(2)?
- When disconnected customers call utilities during qualifying severe weather (including wildfire in 0406) are Customer Service Representative (CSRs) offering bill discount program customers and medical certificate customers the ability to reconnect with no up-front costs pursuant to OAR 860-021-0330(3)?

We thank Staff for their continued engagement and dedication to this matter and look forward to next steps.

Respectfully submitted this 24th day of February, 2026,

[4] Docket No. RO 18: https://apps.puc.state.or.us/edockets/docket.asp?DocketID=24830

/s/ Sarah Wochele
Oregon Citizens' Utility Board

/s/ Jamie Pang
Oregon Just Transition Alliance

/s/ Anahi Segovia Rodriguez
Verde

/s/ Siraat Younas
Community Energy Project

NW Natural®

Rates & Regulatory Affairs
UG 527
NW Natural Alternative Rate Mechanism
Data Request Response

Request No.: UG 527 CUB DR 31

Per NW Natural's Docket No RO 16 reporting from Q4 2025, the Company indicates it disconnected 139 accounts receiving a bill discount in November 2025 and 213 accounts receiving a bill discount in December 2025.

a. What dates did the Company begin and end its temporary winter moratorium on disconnections for customers enrolled in its BDP and/or medical certificate customers?

    i. Please also describe the Company's temporary moratorium policies.

b. Explain how/why 139 accounts were disconnected for non-payment in November 2025 despite the moratorium?

c. Explain how/why 213 accounts were disconnected for non-payment in December 2025 despite the moratorium?

d. When the Company instituted the limited-scale moratorium (for bill discount program customers and medical certificate customers only), did it immediately contact BDP customers who were disconnected the day, or days prior, to reconnect them? Please explain the Company's process for handling this with temporal components.

Response:

NW Natural has discovered that we did not implement the voluntary temporary winter disconnect moratorium for bill discount participants as intended. In mid- November the Company voluntarily committed to a temporary disconnect moratorium for bill discount and medical certificate customers due to the uncertainty and impacts caused by the federal government shutdown. However, a mistake was made in that an internal miscommunication caused us to continue disconnections for non-payment for these customers despite processes being put in place to do so. NW Natural regrets that its actions did not match its commitment to our customers experiencing economic hardship at this time. This mistake occurred as the Company was implementing the significant technological and process changes required with the new rules from the conclusion of AR 671 and additional actions ordered in UM 2211, which have taken place.

From November 15 through December 31, 192 bill discount participants were disconnected for non-payment. There were no medical certificate customers that were disconnected.

As of February 18, 2026, it was determined that of those 192 customers, 143 have been reconnected. Any fees that were charged with those reconnections have been refunded (approximately $4,890). Of the 49 customers that have not reconnected, 27 have a new customer at the premises with active gas service. NW Natural reached out to the remaining 22 customers that have not yet reconnected to schedule reconnections with no charges and offering extended time payment arrangements. Currently, of those 22 calls, one was reconnected the same day they were called, 11 had voicemails left to contact the Company, and the remaining 10 had either moved, stated they wanted the gas to remain off, or had phone numbers that did not work/go through.

Supplemental Response:

As explained in the response to UG 527 CUB DR 35, we have refined the number of customers impacted. This supplement provides additional detail to include the 22 additional impacted Oregon customers.

From November 15 through December 31, 214 bill discount participants were disconnected for non-payment on a system basis. On an Oregon basis, 198 customers were impacted. There were no medical certificate customers that were disconnected.

Of the 198 Oregon customers impacted, 176 have been reconnected. Any reconnection fees have been refunded. Of the 22 Oregon customers that had not reconnected by February 19, 2026, 1 was reconnected on February 19, 2026, 11 were left voicemails to contact the Company, and the remaining 10 had either moved, stated they wanted the gas to remain off, or had phone numbers that did not work/go through. Please see Supplemental Response to UG 527 CUB DR 34 for a table detailing the number of impacted customers.

NW Natural®

Rates & Regulatory Affairs
UG 527
NW Natural Alternative Rate Mechanism
Data Request Response

Request No.: UG 527 CUB DR 33

Regarding the Bill Discount Program (BDP) households who NW Natural disconnected in November and December 2025 during the winter moratorium; Please provide all responses in public and confidential versions, where applicable:

a. Provide the number of people, not just the number of accounts, in the disconnected households, based on the household size reported by each impacted account when it signed up for the Company's Bill Discount Program (BDP)

b. For each month, provide all zip codes of the impacted households;

c. Please identify, per household, protecting identifying customer information where appropriate:

    i. The bill discount tier the household was in at the time of disconnection, and if that tier has since changed and when;

    ii. The number of times, and in what months, the household was previously disconnected in 2025 and 2024;

    iii. The amounts past due at the time of reconnection, following the households' November or December 2025 disconnection;

    iv. The amount each customer paid to reconnect (including any arrearages, reconnection fees);

    v. The length of time they remained disconnected, including the dates;

    vi. If there was a qualifying severe weather event in effect during their disconnection;

    vii. Whether the customer entered the disconnection cue again in the three months following their disconnection in November or December, and if they were disconnected again since;

    viii. Indicate if they are enrolled in multi-family or single family household;

d. How many impacted customers received an arrearage relief grant from the Company, per Schedule D, since they were disconnected in November or December 2025?

Response:

See Confidential UG 527 CUB DR 33 Attachment 1, which contains distinct (randomized ID) account disconnection data with 3 tabs representing the data requested and itemized below:

a. Provide the number of people, not just the number of accounts, in the disconnected households, based on the household size reported by each impacted account when it signed up for the Company's Bill Discount Program (BDP)

***** See Confidential UG 527 CUB DR 33 Attachment 1, Tab 1, column E (Household).***

b. For each month, provide all zip codes of the impacted households;

***** See Confidential UG 527 CUB DR 33 Attachment 1, Tab 1, column B (Zip).***

c. Please identify, per household, protecting identifying customer information where appropriate:

i. The bill discount tier the household was in at the time of disconnection, and if that tier has since changed and when;

***** See Confidential UG 527 CUB DR 33 Attachment 1, Tab 1, column F, G & H.***

ii. The number of times, and in what months, the household was previously disconnected in 2025 and 2024;

***** See Confidential UG 527 CUB DR 33 Attachment 1, Tab 2 for a list by ID of each disconnection between 2024 and 2025 for accounts listed in Tab 1.***

iii. The amounts past due at the time of reconnection, following the households' November or December 2025 disconnection;

***** See Confidential UG 527 CUB DR 33 Attachment 1, Tab 1, column M. Amount represents the past due amount associated with the disconnection action and at the time of disconnection. Any amounts between $50 and $150 are related to customers on pre-existing payment plans, which are subject to disconnection at a $50 past due balance.***

iv. The amount each customer paid to reconnect (including any arrearages, reconnection fees);

***** See Confidential UG 527 CUB DR 33 Attachment 1, Tab 1, column N. Amount represents the sum of payment on the first day post-disconnection.***

v. The length of time they remained disconnected, including the dates;

***** See Confidential UG 527 CUB DR 33 Attachment 1, Tab 1, column K & L.***

vi. If there was a qualifying severe weather event in effect during their disconnection;

No weather moratorium events were declared for the weather zones of accounts in the disconnection list.

vii. Whether the customer entered the disconnection cue again in the three months following their disconnection in November or December, and if they were disconnected again since;

***** See Confidential UG 527 CUB DR 33 Attachment 1, Tab 3 for a list by ID of each disconnection between January 1st and March 11th, 2026 for accounts listed in Tab 1.***

viii. Indicate if they are enrolled in multi-family or single family household;

***** See Confidential UG 527 CUB DR 33 Attachment 1, Tab 1, column C (Dwelling Type).***

d. How many impacted customers received an arrearage relief grant from the Company, per Schedule D, since they were disconnected in November or December 2025?

9 Distinct Accounts.

ID	ZIP	Dwelling Type	Discount Start	Household	Disconnection Discount Tier	New Discount Tier	New Discount Effective Date	Disconnect Order Date	Disconnect Completion Date	Disconnect Days Duration	Reconnect Date	Past Due at Disconnect	Paid after Disconnect
31586	97103	Single-Family	7/17/2025	3	30%	30%	2/12/2026	12/5/2025	12/8/2025	16	12/24/2025	$ 130.70	$ 252.43
91109	97060	Single-Family	6/4/2025	2	15%	NA	NA	12/8/2025	12/9/2025	1	12/10/2025	$ 69.91	$ 168.55
38838	97113	Single-Family	2/5/2024	2	15%	NA	NA	11/21/2025	11/24/2025	NA	NA	$ 639.00	$ -
100904	97229	Single-Family	6/20/2025	1	15%	NA	NA	12/15/2025	12/16/2025	3	12/19/2025	$ 198.07	$ 333.60
113404	97211	Single-Family	4/24/2024	4	15%	NA	NA	11/19/2025	11/20/2025	1	11/21/2025	$ 152.16	$ 196.53
113955	97211	Single-Family	6/26/2025	0	15%	NA	NA	11/20/2025	11/24/2025	7	12/1/2025	$ 157.95	$ 151.72
141140	97062	Single-Family	3/24/2025	1	30%	NA	NA	11/20/2025	11/25/2025	0	11/25/2025	$ 156.00	$ 412.40
171018	97123	Single-Family	8/25/2025	2	50%	15%	11/20/2025	11/19/2025	11/20/2025	1	11/21/2025	$ 69.55	$ 140.00
180416	97123	Multi-Family	11/20/2025	3	30%	30%	12/2/2025	12/19/2025	12/20/2025	0	12/29/2025	$ 93.30	$ 100.00
205020	97216	Single-Family	11/19/2024	1	15%	NA	NA	11/14/2025	11/17/2025	2	11/19/2025	$ 189.39	$ 120.43
206865	97368	Single-Family	4/18/2025	3	30%	NA	NA	12/15/2025	12/17/2025	0	12/17/2025	$ 110.00	$ 309.31
208354	97007	Single-Family	10/1/2025	1	30%	30%	12/4/2025	12/2/2025	12/5/2025	2	12/5/2025	$ 99.78	$ 313.92
211941	97206	Single-Family	12/23/2025	2	15%	NA	NA	12/23/2025	12/30/2025	1	12/31/2025	$ 118.19	$ 118.19
231542	97045	Single-Family	11/1/2024	1	30%	NA	NA	12/15/2025	12/17/2025	1	12/18/2025	$ 116.00	$ 160.00
237923	97015	Single-Family	5/8/2025	3	30%	30%	12/15/2025	12/4/2025	12/8/2025	0	12/8/2025	$ 54.79	$ 260.41
238839	97266	Single-Family	2/7/2025	1	30%	30%	2/3/2026	11/25/2025	12/1/2025	1	12/2/2025	$ 91.36	$ 118.10
243451	97266	Single-Family	9/24/2025	2	30%	NA	NA	12/23/2025	12/29/2025	0	12/29/2025	$ 67.93	$ 239.63
248617	97211	Single-Family	2/10/2025	1	30%	NA	NA	12/12/2025	12/15/2025	2	12/17/2025	$ 58.68	$ 161.14
254758	97304	Single-Family	6/27/2025	3	15%	NA	NA	11/20/2025	11/24/2025	2	11/26/2025	$ 191.11	$ 277.38
272281	97303	Single-Family	3/21/2025	3	30%	NA	NA	11/20/2025	11/24/2025	7	12/1/2025	$ 59.93	$ 240.96
272771	97322	Single-Family	4/7/2025	1	30%	NA	NA	12/9/2025	12/10/2025	50	1/29/2026	$ 155.20	$ 261.09
304791	97230	Single-Family	3/1/2024	1	15%	50%	1/23/2026	12/10/2025	12/11/2025	4	12/15/2025	$ 201.92	$ 300.00
305724	97223	Single-Family	7/7/2025	4	15%	NA	NA	12/10/2025	12/11/2025	0	12/11/2025	$ 205.80	$ 416.01
315712	97045	Single-Family	4/14/2025	1	50%	NA	NA	12/12/2025	12/18/2025	0	12/18/2025	$ 73.99	$ 282.18
316493	97116	Single-Family	12/1/2025	0	15%	50%	12/30/2025	12/23/2025	12/30/2025	1	12/31/2025	$ 75.81	$ 269.16
318234	97233	Single-Family	12/12/2023	5	15%	NA	NA	11/26/2025	12/1/2025	0	12/1/2025	$ 262.68	$ 282.35
331898	97032	Single-Family	8/5/2025	2	50%	85%	12/30/2025	12/23/2025	12/30/2025	1	12/31/2025	$ 175.11	$ 67.09
343011	97071	Single-Family	6/18/2025	1	50%	85%	1/2/2026	12/23/2025	12/30/2025	NA	NA	$ 71.91	$ -
356964	97080	Single-Family	8/5/2025	5	50%	NA	NA	12/1/2025	12/2/2025	1	12/3/2025	$ 163.14	$ 163.14
358744	97305	Single-Family	11/1/2024	6	30%	NA	NA	11/26/2025	12/1/2025	NA	NA	$ 300.00	$ -
360637	97006	Single-Family	10/1/2024	4	15%	NA	NA	12/16/2025	12/17/2025	0	12/17/2025	$ 191.78	$ 436.46
399124	97034	Single-Family	11/1/2024	2	30%	NA	NA	11/19/2025	11/20/2025	NA	NA	$ 150.32	$ 178.91
402445	97116	Multi-Family	7/26/2024	4	15%	NA	NA	11/24/2025	11/25/2025	NA	NA	$ 168.75	$ -
405111	97236	Single-Family	6/16/2025	2	30%	NA	NA	11/14/2025	11/17/2025	1	11/18/2025	$ 219.36	$ 259.75
418554	97405	Single-Family	12/12/2025	2	15%	NA	NA	12/1/2025	12/4/2025	43	1/16/2026	$ 268.82	$ 572.67
429676	97301	Single-Family	11/1/2024	6	50%	NA	NA	12/15/2025	12/18/2025	NA	NA	$ 122.29	$ -
434487	97080	Multi-Family	8/28/2025	4	50%	NA	NA	12/1/2025	12/2/2025	0	12/2/2025	$ 66.76	$ 220.00
449651	97230	Single-Family	9/3/2025	4	30%	NA	NA	11/26/2025	12/1/2025	78	2/17/2026	$ 54.73	$ 50.00
452671	97301	Single-Family	1/9/2025	4	50%	NA	NA	12/12/2025	12/15/2025	NA	NA	$ 167.69	$ -
461828	97219	Single-Family	12/19/2025	7	85%	NA	NA	12/19/2025	12/29/2025	0	12/29/2025	$ 164.38	$ -
463393	97218	Single-Family	10/1/2025	6	30%	NA	NA	12/8/2025	12/9/2025	1	12/10/2025	$ 97.28	$ 146.23
464834	97233	Single-Family	3/25/2025	5	30%	NA	NA	11/26/2025	12/1/2025	0	12/1/2025	$ 158.79	$ 212.72
469811	97266	Single-Family	5/30/2025	2	15%	NA	NA	11/24/2025	11/25/2025	1	11/26/2025	$ 315.00	$ 223.01
489322	97086	Single-Family	7/16/2025	3	85%	NA	NA	11/14/2025	11/17/2025	0	11/17/2025	$ 166.04	$ 253.83
498642	97086	Single-Family	3/31/2025	0	15%	85%	12/18/2025	12/16/2025	12/17/2025	1	12/18/2025	$ 199.66	$ -
502115	97219	Single-Family	10/1/2025	4	30%	NA	NA	11/20/2025	11/24/2025	1	11/25/2025	$ 72.70	$ 201.07
508694	97071	Single-Family	10/1/2025	3	50%	NA	NA	11/21/2025	11/24/2025	1	11/25/2025	$ 154.25	$ 177.19
508758	97211	Single-Family	5/27/2025	5	30%	NA	NA	11/20/2025	11/24/2025	1	11/25/2025	$ 292.00	$ 296.39
513138	97103	Multi-Family	12/26/2024	3	30%	NA	NA	12/1/2025	12/2/2025	2	12/4/2025	$ 177.49	$ 338.70
517795	97089	Single-Family	10/1/2025	7	30%	85%	12/9/2025	12/4/2025	12/8/2025	1	12/10/2025	$ 77.76	$ 43.81
518246	97477	Single-Family	6/9/2025	2	50%	NA	NA	12/16/2025	12/17/2025	1	12/18/2025	$ 94.31	$ 250.00
523101	97301	Single-Family	10/1/2025	3	30%	NA	NA	12/12/2025	12/15/2025	1	12/16/2025	$ 153.84	$ 200.00
543023	97303	Multi-Family	11/1/2024	3	30%	30%	12/31/2025	12/23/2025	12/30/2025	1	12/31/2025	$ 82.14	$ 141.00
548734	97038	Single-Family	7/1/2025	3	15%	NA	NA	12/4/2025	12/8/2025	1	12/9/2025	$ 184.00	$ 138.25
557576	97202	Multi-Family	7/28/2025	2	15%	NA	NA	11/24/2025	11/25/2025	1	11/26/2025	$ 68.06	$ 111.42
557582	97026	Single-Family	10/16/2025	1	50%	NA	NA	12/23/2025	12/30/2025	6	1/5/2026	$ 61.19	$ 235.86
557636	97146	Single-Family	4/11/2025	2	50%	NA	NA	12/10/2025	12/11/2025	7	12/18/2025	$ 153.10	$ 195.25
561716	97236	Single-Family	9/20/2025	1	30%	NA	NA	11/26/2025	12/2/2025	1	12/3/2025	$ 84.83	$ 122.68
566987	97215	Single-Family	4/14/2025	3	50%	NA	NA	12/5/2025	12/8/2025	1	12/9/2025	$ 330.87	$ 995.36
571118	97211	Multi-Family	6/9/2025	0	15%	85%	12/15/2025	12/12/2025	12/15/2025	0	12/15/2025	$ 55.06	$ 144.82
579953	97123	Single-Family	4/20/2025	5	30%	NA	NA	12/19/2025	12/29/2025	NA	NA	$ 152.60	$ -
583005	97236	Single-Family	4/4/2024	0	15%	50%	1/23/2026	12/2/2025	12/3/2025	51	1/23/2026	$ 63.98	$ 431.21
587279	97206	Single-Family	7/31/2025	8	50%	85%	1/2/2026	12/23/2025	12/30/2025	3	1/2/2026	$ 123.71	$ 321.30
588880	97007	Single-Family	11/1/2024	3	30%	NA	NA	12/3/2025	12/4/2025	1	12/5/2025	$ 97.00	$ 264.84
591667	97206	Single-Family	8/4/2025	6	50%	NA	NA	11/20/2025	12/1/2025	1	12/2/2025	$ 50.00	$ 141.32
592928	97078	Multi-Family	11/1/2024	2	50%	NA	NA	12/4/2025	12/8/2025	NA	NA	$ 161.61	$ -
598221	97305	Single-Family	7/5/2024	0	15%	85%	12/22/2025	12/2/2025	12/3/2025	21	12/24/2025	$ 81.86	$ -
598339	97124	Single-Family	4/24/2025	4	30%	NA	NA	12/23/2025	12/30/2025	1	12/31/2025	$ 88.03	$ 200.00
601472	97321	Single-Family	6/3/2025	4	50%	85%	12/4/2025	12/3/2025	12/4/2025	0	12/4/2025	$ 64.86	$ -
602203	97103	Single-Family	1/28/2025	5	15%	NA	NA	12/1/2025	12/2/2025	0	12/2/2025	$ 251.62	$ 265.66
602752	97005	Single-Family	5/9/2025	0	15%	85%	12/10/2025	12/8/2025	12/9/2025	2	12/11/2025	$ 177.20	$ 150.00
604432	97225	Single-Family	1/27/2025	0	15%	30%	2/27/2026	12/22/2025	12/29/2025	1	12/30/2025	$ 160.74	$ 191.23
604517	97034	Single-Family	11/1/2024	2	30%	85%	2/19/2026	12/19/2025	12/29/2025	24	1/22/2026	$ 232.40	$ 571.04
604825	97303	Single-Family	10/1/2025	3	50%	NA	NA	11/20/2025	11/25/2025	NA	NA	$ 78.96	$ -
605623	97301	Single-Family	10/1/2024	1	15%	NA	NA	12/12/2025	12/15/2025	NA	NA	$ 157.02	$ -
608292	97220	Single-Family	4/11/2025	4	30%	NA	NA	11/14/2025	11/17/2025	3	11/20/2025	$ 96.96	$ 296.54
608321	97305	Single-Family	10/1/2025	3	50%	NA	NA	11/26/2025	12/1/2025	2	12/3/2025	$ 63.05	$ 144.03
611185	97214	Multi-Family	11/1/2024	1	30%	NA	NA	11/21/2025	11/24/2025	NA	NA	$ 50.00	$ -
613455	97266	Single-Family	5/20/2025	9	50%	NA	NA	11/25/2025	12/1/2025	1	12/2/2025	$ 66.60	$ 186.87
622402	97402	Single-Family	9/25/2025	3	15%	NA	NA	11/25/2025	12/1/2025	1	12/2/2025	$ 152.34	$ 105.42
628031	97220	Single-Family	2/26/2025	5	30%	NA	NA	11/14/2025	11/17/2025	1	11/18/2025	$ 159.01	$ 219.46
628578	97003	Single-Family	12/5/2025	4	30%	NA	NA	12/5/2025	12/8/2025	1	12/9/2025	$ 62.00	$ 201.52
631743	97233	Single-Family	10/1/2025	4	30%	NA	NA	11/26/2025	12/2/2025	1	12/3/2025	$ 167.21	$ 120.00
638835	97305	Single-Family	6/23/2025	0	15%	NA	NA	12/23/2025	12/30/2025	NA	NA	$ 152.81	$ -
648894	97006	Multi-Family	10/6/2025	6	50%	NA	NA	12/8/2025	12/10/2025	0	12/10/2025	$ 54.00	$ 205.89
658881	97220	Single-Family	11/1/2024	7	30%	30%	2/9/2026	12/16/2025	12/17/2025	0	12/17/2025	$ 120.29	$ 513.14
660054	97113	Single-Family	11/1/2024	4	50%	NA	NA	12/22/2025	12/30/2025	4	1/3/2026	$ 155.76	$ 93.35
660776	97355	Single-Family	9/24/2025	3	30%	NA	NA	11/13/2025	11/17/2025	16	12/3/2025	$ 152.00	$ 203.96
661227	97389	Single-Family	1/31/2025	0	85%	12/19/2025	12/2/2025	12/3/2025	16	12/19/2025	$ 173.21	$ 237.41
662986	97030	Single-Family	3/12/2025	7	15%	NA	NA	12/9/2025	12/10/2025	1	12/11/2025	$ 273.00	$ 128.04
664469	97229	Single-Family	5/16/2025	3	30%	NA	NA	11/14/2025	11/17/2025	1	11/18/2025	$ 71.56	$ 229.48
668550	97233	Single-Family	7/2/2025	2	15%	NA	NA	11/24/2025	12/29/2025	0	12/29/2025	$ 146.41	$ 484.33
672461	97128	Multi-Family	4/21/2025	2	15%	NA	NA	12/16/2025	12/17/2025	1	12/18/2025	$ 67.79	$ 132.69
673217	97006	Single-Family	8/11/2025	0	15%	50%	12/15/2025	12/5/2025	12/8/2025	8	12/16/2025	$ 52.73	$ 505.00
673773	97086	Single-Family	12/4/2025	5	50%	NA	NA	12/15/2025	12/16/2025	0	12/16/2025	$ 217.30	$ 411.09
674773	97225	Single-Family	2/20/2025	5	15%	NA	NA	12/12/2025	12/15/2025	1	12/16/2025	$ 253.83	$ 216.77
677754	97236	Single-Family	11/8/2024	10	15%	NA	NA	12/3/2025	12/4/2025	1	12/5/2025	$ 393.84	$ 592.87
682896	97086	Single-Family	1/13/2025	8	30%	NA	NA	12/15/2025	12/16/2025	0	12/16/2025	$ 196.00	$ 319.00
684886	97266	Single-Family	11/1/2024	3	50%	85%	1/14/2026	11/13/2025	11/17/2025	2	11/19/2025	$ 147.96	$ 163.28
686091	97211	Single-Family	2/10/2025	0	15%	15%	12/16/2025	12/12/2025	12/15/2025	1	12/16/2025	$ 157.53	$ 354.66
686146	97229	Single-Family	6/18/2025	4	30%	NA	NA	12/16/2025	12/17/2025	1	12/18/2025	$ 228.84	$ 397.06
686183	97233	Multi-Family	7/14/2025	0	15%	50%	12/10/2025	12/8/2025	12/10/2025	1	12/11/2025	$ 223.59	$ 208.89
686500	97301	Single-Family	8/13/2025	2	50%	50%	12/15/2025	12/12/2025	12/15/2025	1	12/16/2025	$ 126.00	$ 116.14
686846	97338	Single-Family	2/28/2025	3	30%	NA	NA	11/19/2025	11/20/2025	5	11/25/2025	$ 254.71	$ 339.01
687107	97211	Single-Family	4/25/2025	3	15%	NA	NA	12/19/2025	12/29/2025	4	1/2/2026	$ 161.61	$ 238.40
687786	97222	Single-Family	10/13/2025	4	15%	NA	NA	12/16/2025	12/17/2025	1	12/18/2025	$ 183.98	$ 173.15
690227	97005	Multi-Family	3/20/2025	2	15%	NA	NA	12/12/2025	12/15/2025	7	12/22/2025	$ 176.76	$ 160.63
691424	97080	Single-Family	10/7/2025	5	15%	NA	NA	12/8/2025	12/9/2025	1	12/10/2025	$ 166.49	$ 267.86
692311	97005	Single-Family	4/23/2025	5	30%	NA	NA	12/5/2025	12/8/2025	0	12/8/2025	$ 216.57	$ 216.57
693355	97211	Single-Family	8/12/2025	3	30%	NA	NA	12/12/2025	12/15/2025	0	12/15/2025	$ 87.82	$ 230.41
693625	97229	Single-Family	12/18/2023	0	15%	30%	11/18/2025	11/14/2025	11/17/2025	2	11/19/2025	$ 332.00	$ 267.00
697619	97239	Multi-Family	4/3/2025	1	15%	NA	NA	12/22/2025	12/30/2025	16	1/15/2026	$ 153.03	$ 220.25
697767	97266	Multi-Family	11/1/2024	3	50%	50%	12/1/2025	11/26/2025	12/1/2025	1	12/2/2025	$ 60.61	$ 240.71
697824	97045	Single-Family	6/17/2025	2	50%	NA	NA	11/13/2025	11/17/2025	NA	NA	$ 55.80	$ -
707478	97003	Single-Family	1/6/2025	6	50%	NA	NA	12/5/2025	12/8/2025	NA	NA	$ 201.21	$ -
708315	97236	Single-Family	9/30/2025	2	30%	30%	1/29/2026	12/2/2025	12/3/2025	61	2/2/2026	$ 246.16	$ 714.52
710714	97220	Single-Family	12/19/2024	2	15%	30%	1/12/2026	11/17/2025	11/18/2025	0	11/18/2025	$ 115.66	$ 331.36
712880	97233	Single-Family	3/6/2025	0	15%	50%	2/4/2026	11/26/2025	12/1/2025	0	12/1/2025	$ 326.00	$ 243.95
712899	97220	Single-Family	5/19/2025	2	30%	NA	NA	12/16/2025	12/17/2025	3	12/20/2025	$ 54.98	$ 134.82
713728	97080	Single-Family	6/10/2024	6	15%	30%	12/10/2025	12/8/2025	12/9/2025	2	12/11/2025	$ 159.69	$ 144.38
714699	97302	Single-Family	10/1/2025	6	30%	NA	NA	12/2/2025	12/3/2025	0	12/3/2025	$ 225.22	$ 393.33
715029	97266	Multi-Family	4/24/2025	0	15%	50%	11/17/2025	11/13/2025	11/17/2025	1	11/18/2025	$ 165.17	$ 96.50
719973	97338	Single-Family	2/17/2025	5	15%	NA	NA	11/18/2025	11/19/2025	0	11/19/2025	$ 262.71	$ 363.00
722377	97233	Single-Family	6/13/2025	5	30%	NA	NA	12/24/2025	12/29/2025	0	12/29/2025	$ 152.00	$ 290.09
722425	97301	Multi-Family	2/21/2025	6	50%	NA	NA	12/16/2025	12/17/2025	1	12/18/2025	$ 94.00	$ 206.69
728321	97006	Single-Family	1/27/2025	0	15%	85%	11/17/2025	11/14/2025	11/17/2025	0	11/17/2025	$ 199.87	$ 126.87
729252	97209	Multi-Family	10/1/2025	1	85%	NA	NA	11/26/2025	12/2/2025	2	12/4/2025	$ 85.87	$ -
736258	97003	Single-Family	7/11/2025	4	30%	NA	NA	12/5/2025	12/8/2025	0	12/8/2025	$ 154.79	$ 344.75
738495	97230	Single-Family	11/1/2024	3	50%	50%	12/12/2025	12/10/2025	12/11/2025	4	12/15/2025	$ 60.65	$ 261.60
740262	97233	Multi-Family	11/1/2024	5	30%	NA	NA	11/26/2025	12/1/2025	NA	NA	$ 157.77	$ -
741074	97138	Single-Family	8/18/2025	4	50%	NA	NA	11/17/2025	11/18/2025	NA	NA	$ 63.63	$ -
742716	97086	Multi-Family	11/1/2024	5	30%	NA	NA	12/15/2025	12/16/2025	6	12/22/2025	$ 150.65	$ 164.31
743137	97062	Single-Family	1/7/2025	1	50%	50%	12/8/2025	12/4/2025	12/8/2025	2	12/10/2025	$ 119.92	$ 169.21
745262	97301	Single-Family	9/9/2025	2	30%	85%	12/17/2025	12/12/2025	12/15/2025	NA	NA	$ 52.00	$ -
745596	97303	Single-Family	4/1/2025	1	50%	NA	NA	11/21/2025	11/25/2025	NA	NA	$ 113.13	$ 491.37
747406	97205	Multi-Family	9/9/2025	1	50%	NA	NA	12/23/2025	12/30/2025	14	1/13/2026	$ 67.79	$ 104.53
747837	97266	Multi-Family	9/9/2024	0	15%	NA	NA	12/1/2025	12/2/2025	15	12/17/2025	$ 169.75	$ 218.00
749792	97062	Single-Family	11/21/2024	3	15%	15%	2/2/2026	12/4/2025	12/8/2025	1	12/9/2025	$ 117.64	$ 237.52
751388	97305	Single-Family	8/7/2024	3	15%	NA	NA	12/24/2025	12/30/2025	1	12/31/2025	$ 126.00	$ 115.17
752641	97006	Single-Family	6/30/2025	6	50%	NA	NA	12/5/2025	12/8/2025	1	12/9/2025	$ 94.20	$ 157.18
753481	97132	Multi-Family	11/1/2024	4	30%	NA	NA	12/12/2025	12/15/2025	1	12/16/2025	$ 98.40	$ 204.04
753869	97301	Single-Family	10/27/2025	0	15%	85%	12/22/2025	12/12/2025	12/16/2025	6	12/22/2025	$ 166.29	$ -
755537	97303	Single-Family	4/16/2025	4	30%	NA	NA	11/20/2025	11/24/2025	NA	NA	$ 81.84	$ -
758473	97303	Multi-Family	11/1/2024	2	30%	NA	NA	12/22/2025	12/30/2025	NA	NA	$ 155.97	$ -
759166	97218	Single-Family	8/21/2025	5	50%	NA	NA	12/23/2025	12/29/2025	5	1/3/2026	$ 55.56	$ 192.00
759433	97202	Single-Family	6/6/2025	1	15%	50%	11/25/2025	11/24/2025	11/25/2025	0	11/25/2025	$ 89.58	$ 257.88
759965	97062	Single-Family	12/3/2025	4	30%	NA	NA	12/4/2025	12/8/2025	1	12/9/2025	$ 201.69	$ 231.00
760642	97212	Single-Family	11/1/2024	5	50%	15%	3/2/2026	12/12/2025	12/15/2025	NA	NA	$ 166.86	$ -
761215	97305	Single-Family	11/1/2024	5	30%	30%	12/30/2025	12/24/2025	12/30/2025	0	12/30/2025	$ 163.62	$ 284.19
761219	97206	Single-Family	12/23/2025	2	50%	50%	2/25/2026	12/23/2025	12/30/2025	14	1/13/2026	$ 72.65	$ 210.35
761221	97366	Multi-Family	2/25/2025	2	15%	50%	12/3/2025	12/2/2025	12/2/2025	2	12/4/2025	$ 70.00	$ 178.36
761349	97302	Single-Family	4/11/2025	2	30%	NA	NA	12/2/2025	12/3/2025	NA	NA	$ 156.78	$ -
762678	97103	Multi-Family	10/1/2025	3	50%	NA	NA	12/1/2025	12/2/2025	NA	NA	$ 87.61	$ -
762793	97220	Single-Family	2/25/2025	5	15%	NA	NA	12/15/2025	12/16/2025	1	12/17/2025	$ 81.38	$ 201.00
763272	97266	Single-Family	7/29/2025	9	50%	NA	NA	12/23/2025	12/30/2025	NA	NA	$ 133.00	$ -
763506	97233	Single-Family	11/22/2024	2	50%	NA	NA	12/8/2025	12/10/2025	2	12/12/2025	$ 70.19	$ 141.87
764196	97027	Multi-Family	11/1/2024	2	50%	50%	12/1/2025	11/26/2025	12/1/2025	1	12/2/2025	$ 56.46	$ 88.10
764250	97213	Single-Family	3/26/2025	2	30%	NA	NA	12/15/2025	12/16/2025	0	12/16/2025	$ 160.77	$ 200.89
764267	97380	Single-Family	11/1/2024	5	30%	50%	2/5/2026	12/5/2025	12/9/2025	NA	NA	$ 167.05	$ 368.92
765029	97202	Single-Family	9/24/2025	1	50%	NA	NA	11/24/2025	11/25/2025	1	11/26/2025	$ 61.00	$ 282.51
765235	97003	Multi-Family	6/12/2025	5	50%	NA	NA	12/5/2025	12/8/2025	2	12/10/2025	$ 81.63	$ 156.36
765948	97086	Single-Family	10/1/2024	2	15%	NA	NA	12/4/2025	12/8/2025	1	12/9/2025	$ 158.80	$ 321.86
765991	97006	Multi-Family	8/7/2025	4	85%	NA	NA	12/8/2025	12/10/2025	2	12/12/2025	$ 169.82	$ 20.42
766067	97302	Single-Family	11/1/2024	2	85%	NA	NA	12/2/2025	12/3/2025	NA	NA	$ 152.65	$ -
766688	97306	Single-Family	10/1/2025	3	50%	NA	NA	12/5/2025	12/8/2025	NA	NA	$ 93.35	$ -
768802	97024	Single-Family	6/16/2025	4	15%	NA	NA	12/12/2025	12/16/2025	2	12/18/2025	$ 496.52	$ 514.85
769348	97305	Multi-Family	11/1/2024	2	30%	NA	NA	12/1/2025	12/2/2025	NA	NA	$ 159.80	$ 100.00
769752	97064	Single-Family	6/20/2025	6	15%	NA	NA	12/23/2025	12/30/2025	1	12/31/2025	$ 67.00	$ 214.92
769800	97086	Single-Family	12/12/2024	2	85%	NA	NA	11/13/2025	11/17/2025	NA	NA	$ 154.12	$ -
770728	97309	Multi-Family	3/31/2025	1	50%	NA	NA	12/1/2025	12/2/2025	79	2/19/2026	$ 112.89	$ -
771310	97301	Single-Family	11/1/2024	4	30%	NA	NA	12/12/2025	12/15/2025	0	12/15/2025	$ 181.07	$ 258.45
772500	97330	Single-Family	1/31/2025	2	50%	NA	NA	12/5/2025	12/8/2025	NA	NA	$ 68.70	$ -
773248	97229	Single-Family	5/27/2025	3	15%	NA	NA	12/16/2025	12/17/2025	NA	NA	$ 184.53	$ -
774877	97302	Single-Family	10/31/2024	4	15%	NA	NA	12/2/2025	12/3/2025	NA	NA	$ 153.29	$ -
775644	97071	Single-Family	9/30/2025	5	50%	NA	NA	11/21/2025	11/24/2025	2	11/26/2025	$ 170.46	$ 150.00
775821	97322	Single-Family	8/1/2025	5	50%	NA	NA	12/10/2025	12/11/2025	NA	NA	$ 183.93	$ -
775992	97222	Single-Family	12/30/2024	1	30%	NA	NA	12/12/2025	12/16/2025	NA	NA	$ 98.38	$ -
776212	97266	Single-Family	3/13/2025	2	15%	NA	NA	12/29/2025	12/30/2025	NA	NA	$ 154.36	$ -
776332	97266	Single-Family	6/18/2025	2	30%	NA	NA	12/23/2025	12/29/2025	1	12/30/2025	$ 91.66	$ 285.54
777525	97266	Single-Family	12/19/2024	2	15%	15%	12/1/2025	11/25/2025	12/1/2025	NA

782843 97448 Single-Family	4/1/2025	3	50%	NA	NA	12/1/2025	12/3/2025	10	12/13/2025	$	99.00	$ 249.67
783076 97220 Multi-Family	4/4/2025	1	15%	85%	1/15/2026	12/17/2025	12/18/2025	29	1/16/2026	$	196.04	$ -
783507 97062 Single-Family	6/23/2025	4	30%	NA	NA	12/4/2025	12/8/2025	2	12/10/2025	$	62.21	$ 347.32
783606 97068 Single-Family	4/16/2025	1	15%	NA	NA	12/16/2025	12/17/2025	3	12/20/2025	$	117.89	$ 336.81
784192 97230 Multi-Family	10/27/2025	1	15%	NA	NA	12/24/2025	12/29/2025	1	12/30/2025	$	187.94	$ 152.60
786814 97211 Single-Family	7/17/2025	2	15%	NA	NA	11/20/2025	11/24/2025	NA	NA	$	60.07	$ -
788866 97322 Single-Family	9/13/2025	2	50%	NA	NA	12/8/2025	12/11/2025	NA	NA	$	82.00	$ -
792507 97266 Single-Family	9/16/2025	3	30%	NA	NA	12/1/2025	12/2/2025	1	12/3/2025	$	246.31	$ 306.62
792884 97266 Multi-Family	9/23/2025	1	85%	NA	NA	11/24/2025	11/25/2025	NA	NA	$	175.41	$ -
793305 97060 Single-Family	10/2/2025	5	50%	NA	NA	12/9/2025	12/10/2025	1	12/11/2025	$	248.55	$ 258.84

ID	Disconnect Completion Date
31586	12/8/2025
91109	12/9/2025
98038	11/24/2025
100904	12/16/2025
113404	4/24/2024
113404	3/31/2025
113404	11/20/2025
133955	3/28/2024
133955	3/3/2025
133955	11/24/2025
141140	7/29/2024
141140	7/28/2025
141140	11/25/2025
171018	11/20/2025
180416	12/29/2025
205020	11/17/2025
206865	7/17/2025
206865	12/17/2025
208354	6/5/2024
208354	12/3/2025
211941	8/7/2024
211941	3/20/2025
211941	12/30/2025
231542	11/19/2024
231542	6/24/2025
231542	12/17/2025
237923	12/8/2025
238839	12/1/2025
243451	12/29/2025
248617	12/15/2025
254758	1/24/2024
254758	6/25/2024
254758	11/19/2024
254758	2/27/2025
254758	4/30/2025
254758	7/28/2025
254758	11/24/2025
272281	11/24/2025
272771	3/19/2025
272771	12/10/2025
304791	12/11/2025
305724	12/11/2025
315712	12/18/2025
316493	12/30/2025
318234	3/20/2025
318234	12/1/2025
331898	12/30/2025
343011	12/30/2025
356964	8/5/2025
356964	12/2/2025
358744	12/1/2025
360637	6/20/2024
360637	8/21/2024
360637	12/17/2025
399124	11/20/2025
402445	11/25/2025
405111	9/17/2025
405111	11/17/2025
418554	11/24/2025
429676	12/18/2025
434887	12/2/2025
449651	12/1/2025
452671	1/2/2025
452671	12/15/2025
461828	12/29/2025

UG 527 CUB DR 33 Part C2:
The number of times, and in what months, the household was previously disconnected in 2025 and 2024;

ID Column represents a randomized key to a distinct NW Natural Billing Account Number

463393	12/9/2025
464834	7/31/2025
464834	12/1/2025
469812	11/25/2025
489322	11/17/2025
498642	12/17/2025
502115	11/24/2025
508684	10/28/2024
508684	11/24/2025
508758	11/24/2025
511318	1/30/2025
511318	5/7/2025
511318	12/2/2025
517795	12/9/2025
518246	12/17/2025
523101	3/5/2025
523101	12/15/2025
543023	5/28/2025
543023	12/30/2025
548734	12/8/2025
557576	4/17/2025
557576	11/25/2025
557582	12/30/2025
557636	7/17/2025
557636	12/11/2025
561716	12/2/2025
566987	12/8/2025
571318	5/16/2024
571318	12/15/2025
579953	12/29/2025
583005	12/3/2025
587279	12/30/2025
588880	10/3/2024
588880	7/7/2025
588880	12/4/2025
591667	10/15/2024
591667	8/4/2025
591667	12/1/2025
592928	3/12/2024
592928	1/8/2025
592928	12/8/2025
598221	2/1/2024
598221	12/30/2024
598221	12/3/2025
598339	12/30/2025
601472	12/4/2025
602203	10/1/2025
602203	12/2/2025
602752	12/9/2025
604432	7/1/2025
604432	12/29/2025
604517	1/29/2024
604517	12/29/2025
604825	4/1/2025
604825	11/25/2025
605623	12/15/2025
608292	11/17/2025
608321	12/1/2025
611185	10/10/2024
611185	11/24/2025
613455	7/16/2024
613455	12/1/2025
622402	12/1/2025
628031	11/17/2025
628578	12/8/2025
631743	12/2/2025
638835	12/30/2025

648894	12/10/2025
658881	12/17/2025
660054	8/28/2024
660054	12/30/2025
660776	9/15/2025
660776	11/17/2025
661227	12/3/2025
662986	12/10/2025
664469	6/20/2024
664469	8/21/2024
664469	6/24/2025
664469	11/17/2025
668550	7/2/2025
668550	12/29/2025
672463	12/17/2025
673217	12/8/2025
673773	12/16/2025
674773	2/20/2025
674773	10/13/2025
674773	12/15/2025
677754	12/4/2025
682896	7/22/2025
682896	12/16/2025
684886	11/17/2025
686091	12/15/2025
686148	10/16/2025
686148	12/17/2025
686183	12/10/2025
686500	4/4/2024
686500	12/15/2025
686846	2/25/2025
686846	6/23/2025
686846	8/19/2025
686846	11/20/2025
687107	4/24/2024
687107	12/29/2025
687786	7/21/2025
687786	12/17/2025
690227	3/19/2025
690227	12/15/2025
691424	8/12/2025
691424	12/9/2025
692311	10/6/2025
692311	12/8/2025
693355	12/15/2025
693625	4/24/2025
693625	11/17/2025
697619	12/30/2025
697767	12/1/2025
697824	11/17/2025
707478	12/8/2025
708315	12/3/2025
710714	11/18/2025
712880	12/1/2025
712899	5/19/2025
712899	12/17/2025
713728	7/10/2024
713728	12/9/2025
714699	9/30/2024
714699	3/12/2025
714699	7/31/2025
714699	10/1/2025
714699	12/3/2025
715029	11/17/2025
719973	5/23/2024
719973	9/22/2025
719973	11/19/2025

722377	12/29/2025
722425	1/2/2025
722425	8/12/2025
722425	12/17/2025
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729252	12/2/2025
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736258	12/8/2025
738495	12/11/2025
740262	5/20/2024
740262	12/1/2025
741074	11/18/2025
742716	12/16/2025
743137	1/7/2025
743137	12/8/2025
745262	12/15/2025
745596	11/25/2025
747406	12/30/2025
747837	12/2/2025
749792	12/8/2025
751388	8/1/2024
751388	12/30/2025
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753481	8/15/2024
753481	12/12/2024
753481	3/20/2025
753481	6/17/2025
753481	12/15/2025
753869	12/16/2025
755537	11/24/2025
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759965	8/5/2025
759965	12/8/2025
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761221	2/25/2025
761221	8/4/2025
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761349	12/3/2025
762678	12/2/2025
762793	2/24/2025
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763272	12/30/2025
763506	12/10/2025
764196	12/1/2025
764250	3/25/2025
764250	12/16/2025
764267	6/12/2025
764267	12/9/2025
765029	11/25/2025
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783076	12/18/2025
783507	12/8/2025
783606	12/17/2025
784192	12/29/2025
786814	11/24/2025
788866	12/11/2025
792507	12/2/2025
792884	11/25/2025
793305	12/10/2025

ID	Disconnect Completion Date
211941	3/5/2026
238839	2/3/2026
248617	2/12/2026
254758	2/24/2026
508758	3/2/2026
759965	2/10/2026
761215	3/4/2026
793305	2/12/2026

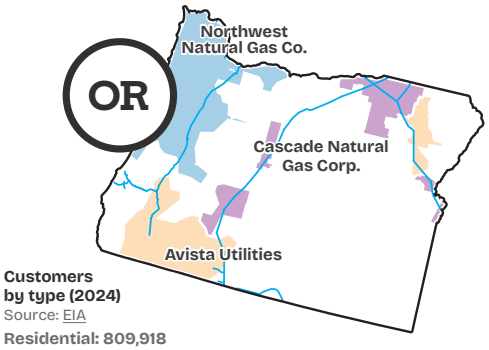
UG 527 CUB DR 33 Part C7:
Whether the customer entered the disconnection cue again in the three months following their disconnection in November or December, and if they were disconnected again since;

ID Column represents a randomized key to a distinct NW Natural Billing Account Number

The FUTURE of HEAT INITIATIVE

Paying More for Less

Rising Gas Bills in Oregon



Customers by type (2024)
Source: EIA

Residential: 809,918
Commercial: 84,777
Industrial: 1,171

Largest investor-owned gas utilities

Northwest Natural Gas Co.
Avista Utilities
Cascade Natural Gas Corp.

Gas bills are on the rise, even though customers are using less gas.

Because of efficiency improvements and fewer heating days, gas consumption per residential customer is declining. The typical Oregon residential gas customer uses 24% less gas today compared to 2000. But the total charge for that gas (supply charge + delivery charge + surcharges) is rising. Over the last five years, residential customer **gas bills have increased ~11% year over year.**

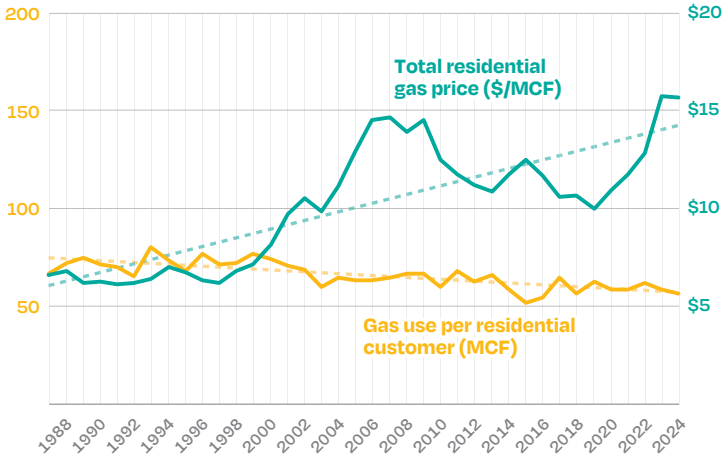
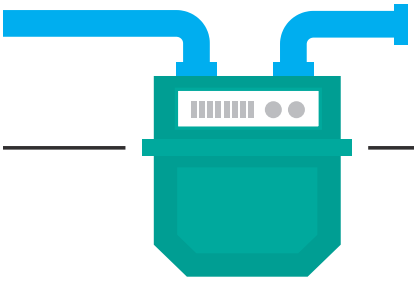


Figure 1: OR gas use per residential customer & total residential cost of gas
Source: EIA



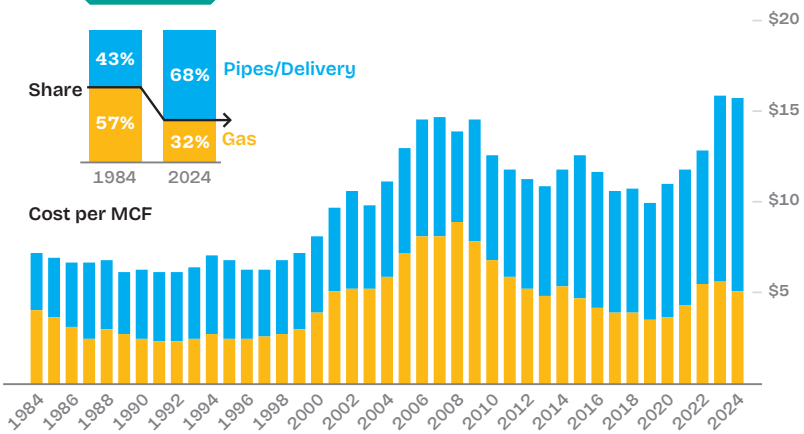


Figure 2: OR residential delivery charges & supply cost of gas
Source: EIA

Customers pay more for pipes ("delivery") than for the gas itself.

Residential gas delivery charges in Oregon have overtaken charges for the gas. In 1984, 57% of a gas bill went toward the fuel itself ("gas") and 43% toward paying for pipes and other infrastructure, utility operating costs, and taxes ("delivery"). In the early 2010s, this flipped. Today, one-third of charges are for gas and two-thirds are for delivery charges that will not fall with lower use.

Aggressive capital spending is driving up customer rates.

Oregon's gas utilities are investing hundreds of millions to excavate and replace old pipelines and install other infrastructure, often taking advantage of state policies that encourage such spending. Over the last 10 years, the three largest gas utilities grew their gas assets from about $3B to over $5B, despite homes using less gas.

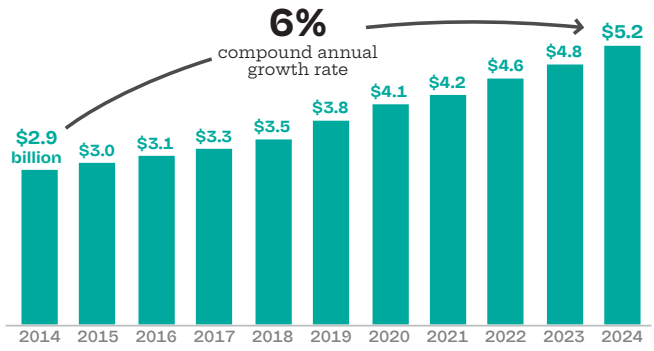


Figure 3: Growth in equipment and facilities for the three largest OR gas companies
Source: Utility annual filings for Northwest Natural, Avista, and Cascade

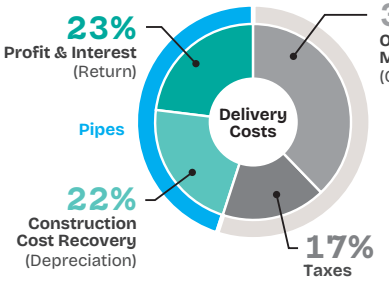


Figure 4: Cost of service breakdown for three largest OR gas utilities
Source: OR Public Utility Commission

Utilities profit from investing in pipes, not selling gas.

In Oregon, 23% of delivery charges for the three largest gas utilities go to profits and financing costs. Their authorized rate of return on these investments ranges from 7.07% to 7.17%. In addition, 22% of delivery charges go to repaying the costs of construction, including significant pipeline replacement.

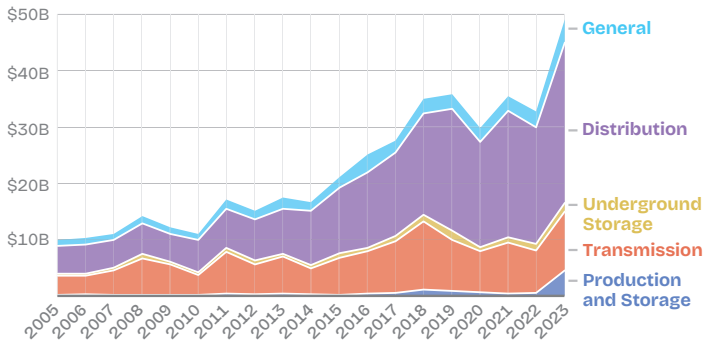
When utilities spend on pipes, they earn more — and delivery charges go up.

National Context

Oregon is not alone: Spending on gas infrastructure is up dramatically across the country.

According to the American Gas Association, "gas utility construction expenditures have been on a sustained upward trajectory since 2011, largely driven by increased investments in safety and infrastructure improvements." As a result, gas delivery rates across the country have nearly doubled since 2011, increasing at more than twice the rate of inflation.

Figure 5: National gas utility capital spending
Source: AGA



Bottom line

Gas customers in Oregon are paying more for less.

Notes and Sources

Figure 1: The Residential Price refers to the total cost paid by residential end-users inclusive of all tax, delivery, commodity, demand and other charges. Gas use per residential customer is calculated as the volume of gas used by residential customers divided by number of residential gas customers. Total residential gas price is from: U.S. Energy Information Administration (EIA), "Natural Gas Prices," Residential Price, State data on residential customers is available from EIA, "Number of Natural Gas Consumers." State data on residential gas volume consumed is available from EIA, "Natural Gas Summary".

Figure 2: The "gas" charge is equal to the Citygate Price of gas; the "delivery" charge is equal to the Residential Price minus the Citygate Price. Citygate Price is the total cost paid by gas distribution companies for gas received at the point where the gas is physically transferred to the companies. See Figure 1 notes for the definition of Residential Price. The data is from: EIA, "Natural Gas Prices," City Gate Price and Residential Price.

Figure 3: Utility annual filings of FERC Form No. 2, OR Supplement, "Gas plant in service."

Figure 4: This figure shows the regulator-approved breakdown for gas company revenue received from the delivery (or "distribution") charges paid by all customers (i.e., total "cost of service"). It excludes the supply charge for gas (which the utility passes through to the customer without markup) and all surcharges and riders. The figure is based on data from the year-end 2024 Earnings Review reports for Northwest Natural (RG 40), Avista (RG 34), and Cascade (RG 36).

Figure 5: American Gas Association (AGA), Resource Library, Gas Utility Construction Capital Expenditures by Type of Facility, 1990-2023.

Map: Natural Gas Service Territories and Pipelines datasets from Homeland Infrastructure Foundation-Level Data (HIFLD).

The Hard Work of Challenging Gas Infrastructure Spending

By Jamie Van Nostrand, FoHI Policy Director

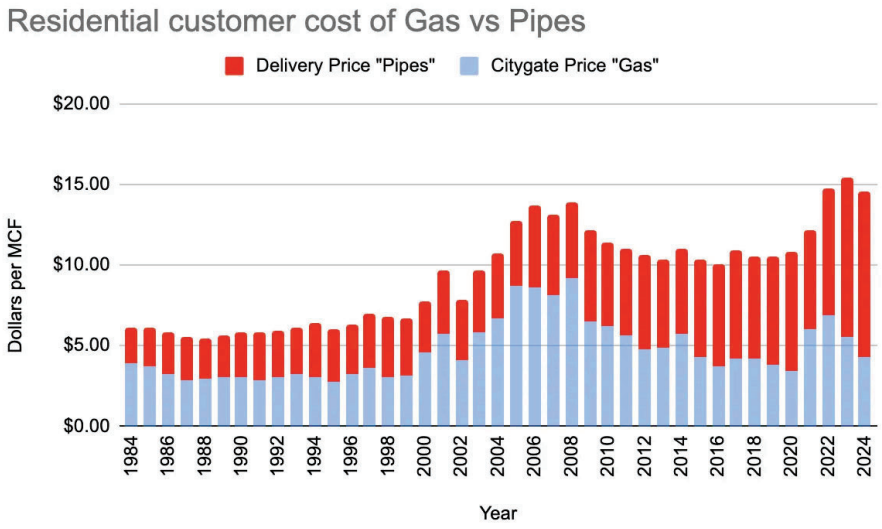
JAMIE VAN NOSTRAND
MAR 04, 2026

7 Share

The cost of delivering natural gas to customers has nearly doubled since 2011, growing at more than twice the rate of inflation.

Today, about two-thirds of a typical gas bill goes to delivery charges, not the gas itself. And unlike the commodity cost, those delivery charges don't fall when customers use less.

This is not an accident. It is the predictable result of how gas utilities are regulated, and it is why scrutinizing infrastructure spending by local gas distribution companies (LDCs) is central to our mission at the Future of Heat Initiative.



Source: EIA city-gate & residential delivery costs

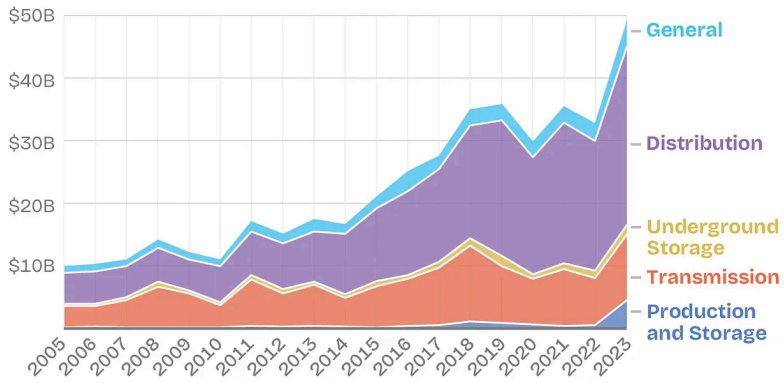
How Rate-of-Return Regulation Creates Spending Incentives

Under rate of return regulation, the money that an LDC spends on pipes gets included in its "rate base" upon which they earn a return, or profit. In other words, the more an LDC spends on pipes, the more it earns – and delivery charges for customers go up.

This creates a strong incentive to over-invest in infrastructure by ***replacing*** pipes, even when lower-cost alternatives exist. Old or at-risk pipe segments can be remediated in several ways: relining, repair, or retirement through non-

pipeline alternatives (NPAs) such as electrification (i.e., replacing the natural gas-fired appliances with electric ones in the buildings served by the pipe segment), thereby avoiding any future maintenance and infrastructure costs on the gas side. Replacement is not the only option. But it is the most profitable one for the LDC, so it has become the default.

Figure 5: National gas utility capital spending
Source: AGA



Source: FoHI's Illinois Affordability Primer, which explains the primary drivers of residential rate increases. You can find all of our state primers here.

The Role of the Regulator

LDC spending on pipe replacement is reviewed by state regulators in rate proceedings, either in general rate cases filed periodically by LDCs or, in many states, specialized infrastructure tracker filings that allow LDCs to recover these expenditures in rates more quickly. In these proceedings, regulators have an opportunity to review LDC infrastructure spending plans and investigate whether an LDC is pursuing the lowest-cost path for customers. If a state commission finds that an LDC failed to demonstrate either that a particular pipe segment needed to be remediated, or that the lowest-cost solution (e.g., relining, repair, or an NPA) was selected, the regulator can "disallow" recovery of a portion of the LDC's expenditures. Disallowed costs cannot be recovered in rates — customers should pay only for costs prudently incurred — and must be borne by the LDC and its shareholders.

In reviewing LDC infrastructure spending, regulators must closely examine three issues in particular:

1. Scope of spending. Did the LDC demonstrate that the pipe segment needed to be replaced? This typically involves a review of the prioritization process used by the LDC to identify pipe replacement projects, and an evaluation of whether the expenditure actually reduced the risk of operating the distribution system.
2. Pace of spending. Did the LDC demonstrate through its risk prioritization process that the safety issues associated with the selected projects warrant urgent attention? Pipes may not need to be remediated for several years, for example, which may provide sufficient time for consideration of NPAs.

3. Evaluation of Alternatives. Did the LDC properly evaluate lower-cost alternatives to that replacement? The LDC should be expected to demonstrate that, once the project is identified as necessary based on risk assessment, it examined all available methods of remediating the pipe and selected the solution that minimizes costs for customers.

The Information Asymmetry Challenge

Regulators need sufficient evidence in the record to perform the necessary analysis of these three issues. The task of developing that evidence typically falls on consumer advocates or or public interest organizations that intervene, or participate, in gas rate proceedings at the PUCs. It is not an easy task, as it involves extensive review of LDC filings – through discovery – and expert testimony in opposition to the LDC filing.

But even well-resourced intervenors face a structural challenge: there is simply no publicly funded, independent research entity focused on gas distribution that can compare to what exists for the electricity sector, leaving intervenors with fewer technical resources to draw on when challenging LDC spending claims.

That gap will be the subject of a future edition of Based Rates. The next edition, however, will examine two recent decisions from the Illinois Commerce Commission that illustrate how rigorous regulatory review can work in practice to reduce excessive infrastructure spending by LDCs.

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June 4, 2024

VIA ELECTRONIC FILING AND HAND DELIVERY

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
Post Office Box 1088
Salem, Oregon 97308-1088

Re: UG 490 – Application of NW Natural for a General Rate Revision
Reply Testimony

Northwest Natural Gas Company, dba NW Natural ("NW Natural" or the "Company"), files herewith its Reply Testimony for the above-mentioned proceeding.

Please note, this filing contains confidential and highly confidential information that represents business-sensitive, non-public information and will be provided subject to General Protective Order No. 23-132 and Modified Protective Order No. 23-480. Documents that contain highly confidential, Sensitive Security Information will be hand delivered.

Please address correspondence on this matter to me with copies to the following:

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Respectfully submitted,

NW Natural

/s/ Zachary Kravitz

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Vice President, Rates & Regulatory Affairs
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Enclosures

NW Natural

CERTIFICATE OF SERVICE
UG 490

I hereby certify that on June 4, 2024, I have served the unredacted, confidential and highly confidential versions of NW NATURAL'S REPLY TESTIMONY upon parties of record in docket UG 490 by electronic delivery. Documents containing sensitive security information will be hand delivered on June 5, 2024.

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DATED June 4, 2024, Portland, Oregon.

/s/ Erica Lee-Pella
Erica Lee-Pella
Rates & Regulatory Affairs, NW Natural

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Reply Testimony of Zachary D. Kravitz

POLICY
EXHIBIT 2200

REDACTED

June 4, 2024

EXHIBIT 2200 – REPLY TESTIMONY – POLICY

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I. INTRODUCTION AND SUMMARY

Q. Are you the same Zachary D. Kravitz who filed Direct Testimony in this proceeding on behalf of Northwest Natural Gas Company dba NW Natural ("NW Natural" or the "Company")?

A. Yes, I co-presented NW Natural/100, Palfreyman-Kravitz.

Q. What is the purpose of your Reply Testimony in this proceeding?

A. The purpose of my testimony is to provide an overview of this proceeding, including summarizing several changes that NW Natural has made in response to parties' Opening Testimony. In addition, I:

- Further explain NW Natural's current operating environment, the continuing importance of NW Natural's system, and the need for collaboration to decarbonize the energy sector;
- Describe how NW Natural's proposals to revise its line extension allowance ("LEA") and its higher fixed charge for new residential premises promote decarbonization and responsible growth while furthering equity;
- Address affordability concerns raised by the Public Utility Commission of Oregon Staff ("Staff") and the Oregon Citizens' Utility Board ("CUB"), while also explaining how multi-year rate plans can mitigate these concerns; and
- Provide a summary of NW Natural's witnesses and their Reply Testimony.

II. UPDATE ON THE RATE CASE

Q. Please summarize your Direct Testimony concerning NW Natural's overall role in Oregon's energy system.

A. In Direct Testimony, we explained how NW Natural's distribution and storage system is vital to meeting Oregon's energy needs. NW Natural provides more energy to Oregonians than any other utility—gas or electric.[1] On the coldest winter days, NW Natural's system meets 90 percent of the energy needs for its residential space and water heat customers.[2] Despite this vast amount of energy delivered, NW Natural's residential and commercial customers' use accounts for approximately five percent of the state's overall emissions, while the electric sector is at 29 percent.[3]

Q. How do the requests for cost recovery in this rate case advance this important work?

A. NW Natural continues to make substantial investments in the safety and reliability of our distribution system and operations. These investments include the Central Resource Center that satisfies the Company's need to have a centrally located resource center in Portland from which operations crews, including emergency response, can be dispatched.

[1] NW Natural/100, Palfreyman-Kravitz/6.

[2] NW Natural/100, Palfreyman-Kravitz/6.

[3] Please note that our Direct Testimony stated that NW Natural's residential and commercial customers' use accounts for less than seven percent of the state's overall emissions. In calculating this number, NW Natural inadvertently included emissions attributed to its Washington customers. NW Natural's residential and commercial customers direct use of natural gas is responsible for approximately five percent of the state's emissions.

In addition, NW Natural is addressing capacity constraints on the system and making investments to ensure the reliability of the Mist Storage Facility, which are crucial to providing reliable natural gas service, especially during the coldest days of winter, as well as pursuing pipeline safety projects to comply with the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration ("PHMSA") requirements. NW Natural is also maintaining its locating and survey capabilities to further ensure the safety of its system.

Regarding information technology and services ("IT&S") systems, NW Natural continues to modernize its systems and perform work to comply with the Department of Homeland Security Transportation Security Administration's cyber security directives. Again, this work helps ensure the safe and reliable delivery of natural gas service to our customers.

Q. Please provide an overview of this rate case thus far.

A. NW Natural, Staff, CUB, the Alliance of Western Energy Consumers ("AWEC"), and the Coalition[4] have been actively working through the issues in this rate case. NW Natural has responded to over 900 data requests from the parties in their review of the filing. All of the parties have participated in constructive settlement conferences, and at this time, the parties have entered into one stipulation regarding NW Natural's proposed cost of long-term debt. That stipulation was filed with the Commission on February 26, 2024.

[4] The Coalition includes the Coalition of Communities of Color, Climate Solutions, Verde, Columbia Riverkeeper, Oregon Environmental Council, Community Energy Project, and Sierra Club.

On April 18, 2024, Staff and intervenors filed Opening Testimony. In this current round of testimony, NW Natural will respond to the positions taken by these parties in their Opening Testimony.

Q. As an initial matter, is NW Natural modifying its request in this rate case based on the process thus far?

A. Yes. There are several areas in this case where NW Natural will be revising its proposal based on the discovery process and feedback from parties in Opening Testimony. NW Natural is requesting a lower revenue requirement compared to its original filing. Specifically, NW Natural's updated revenue requirement request is $152.3 million. While this reflects a modest decrease to our request, it shows that the rate case process is a constructive process where the parties can narrow many issues as the rate case process unfolds. The Reply Testimony of Kyle T. Walker (NW Natural/3800, Walker) describes each of the revenue requirement adjustments that the Company is making in this round of testimony.

Additionally, NW Natural is modifying its LEA proposal to respond to Staff's modeling critiques of the Company's discounted cash flow model. I will summarize these modifications in my testimony. The Reply Testimony of Gregg H. Therrien (NW Natural/4000, Therrien), will discuss them in greater detail.

III. NW NATURAL'S CURRENT OPERATING ENVIRONMENT

A. The Importance of NW Natural's Winter Peaking Capacity

Q. Since NW Natural filed Direct Testimony, has there been severe winter weather in NW Natural's service territory?

A. Yes. In mid-January 2024, NW Natural's service territory experienced severe winter weather, which demonstrated the capacity, resiliency, and reliability values of the natural gas system. On January 13, 2024, as temperatures dropped to 15°F in the Portland area, NW Natural delivered 9 million therms of natural gas to homes and businesses, virtually matching our previous record set in December 2022 for a single gas day, and approximately doubling our average daily winter send out.[5] NW Natural delivered approximately 8 million therms of natural gas for each of the following three days. In addition to matching a single gas day delivery record and sustaining high volumes of natural gas delivery to our customers, NW Natural also broke previous Mist Storage Facility send out records for five consecutive days and delivered over 4.5 million therms of stored natural gas on January 13, 2024.

Q. Was NW Natural's system crucial in meeting overall energy demand during this period of severe winter weather?

A. Yes. From a reliability and resiliency perspective, NW Natural's system performed exceptionally well during this week of severe winter weather (January 13-19). Only

[5] NW Natural/2201, Kravitz/1.

266 of NW Natural customers lost service during this period compared to approximately 707,600 electric customers in our Oregon service territory.[6]

Q. Is the gas system's winter peaking capacity easily replaceable?

A. No, and it appears that the electric system in the Pacific Northwest will struggle to meet growing demand even without factoring in electrification of space-heating load.[7] For example, on May 1, 2024, the Pacific Northwest Utilities Conference Committee ("PNUCC") projected that electric demand in the region will increase by 30 percent over the next decade.[8] More specifically, the forecast projects electricity consumption could increase from about 23,700 average megawatts ("aMW") in 2024 to about 31,100 aMW in 2033 (an increase of 7,400 aMW).[9] According to PNUCC, "[a]n increase of 7,400 aMW is equivalent to having to meet the electricity demand of about seven cities the size of Seattle."[10]

[6] NW Natural/2201, Kravitz/1.

[7] *See e.g.,* Powerex, *Analysis of the January 2024 Winter Weather Event* at 2 (Mar. 6, 2024) (available at https://powerex.com/sites/default/files/2024-03/Analysis%20of%20the%20January%202024%20Winter%20Weather%20Event.pdf) ("During the January 2024 Event, the U.S. Northwest region declared reliability emergencies, experienced elevated wholesale market prices, and required substantial imports from outside the region, the majority of which were supplied from entities in the U.S. Southwest and Rockies region.").

[8] NW Natural/2202, Kravitz/4.

[9] NW Natural/2202, Kravitz/4.

[10] PNUCC, *Demand for Electricity in the Pacific Northwest Could Grow by Over 30% in Next Decade* at 1 (May 1, 2024) (*available at* https://www.pnucc.org/wp-content/uploads/PNUCC-2024-Forecast-Announcement-final-5-01.pdf).

Q. Does PNUCC's forecast show substantial supply deficits in meeting peak January load?

A. Yes. The table below shows that the region currently has a deficit of approximately 2,500 MW in 2025, which grows to approximately 13,700 MW in 2034.[11]

Table 3. Northwest Region Requirements and Resources – Winter Peak

The sum of the individual utilities' firm requirements and resources for the peak hour in January for each of the next 10 years are shown in this table. Firm peak requirements include a planning margin to account for planning uncertainties.

Megawatts	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Firm Requirements										
Load[1/]	34,658	35,633	36,761	38,033	38,940	39,932	40,763	41,411	41,900	42,377
Exports	1,143	1,142	1,142	1,142	1,142	1,142	1,142	1,142	1,142	1,142
Planning Margin[2/]	5,545	5,701	5,882	6,085	6,230	6,389	6,522	6,626	6,704	6,780
Total	41,346	42,476	43,784	45,259	46,312	47,462	48,427	49,178	49,746	50,299
Firm Resources										
Hydro[3/]	23,660	23,658	23,658	23,751	23,651	23,608	23,126	23,126	23,033	22,662
Demand Response	237	315	378	436	456	479	503	523	540	555
Small Thermal/Misc.	801	803	801	801	783	784	785	786	788	789
Natural Gas	7,641	7,901	7,903	7,903	7,903	8,965	8,965	8,965	8,965	8,965
Renewables-Other	447	443	424	419	419	419	415	403	393	393
Solar	103	108	111	102	102	103	103	102	96	94
Wind	1,323	1,321	1,303	1,285	1,276	1,286	1,295	1,283	1,266	1,268
Cogeneration	38	18	16	16	16	16	16	16	16	16
Imports	1,164	1,293	927	696	806	873	788	493	493	493
Nuclear	1,178	1,178	1,178	1,178	1,178	1,178	1,178	1,178	1,178	1,178
Coal	2,240	1,275	1,275	1,275	1,275	147	147	147	147	147
Total	38,831	38,314	37,974	37,864	37,866	37,857	37,322	37,023	36,916	36,561
Surplus (Deficit)	**(2,514)**	**(4,162)**	**(5,810)**	**(7,395)**	**(8,446)**	**(9,605)**	**(11,105)**	**(12,155)**	**(12,830)**	**(13,738)**

[1/] Expected (1-in-2) load net of energy efficiency
[2/] Planning margin is 16% of load (this assumption was updated and set with the *2018 Northwest Regional Forecast*)
[3/] Firm hydro for capacity is the generation expected assuming critical peaking capability as determined by the utility sponsor.

[11] NW Natural/2202, Kravitz/20.

Q. The PNUCC forecast is for the entire region. Is there any specific evidence that shows that Oregon electric utilities' loads will also grow?

A. Yes. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. Would electrifying NW Natural's load exacerbate these resource adequacy issues?

A. Yes. It is important to bear in mind that the period of severe winter weather the region experienced in January 2024 is not especially unique. In Direct Testimony, we referenced an analysis conducted by ICF where the Pacific Northwest experienced very cold weather on December 22, 2022.[12] Electrifying NW Natural's load during the coldest hour of that day would have increased electric consumption by over 80 percent or about 3.4 GW of new electric load. ICF estimated that it

[12] NW Natural/100, Palfreyman-Kravitz/6-7.

would cost tens of billions of dollars to electrify this load with new renewable resources. The recent January 2024 storm reinforces ICF's findings. During this time, there were serious power supply issues associated with meeting existing electric demand, let alone the increase in demand that would be caused by electrifying NW Natural's load.[13] Due to these ongoing power supply issues, the intermittency of renewable generation, and the limitations of battery technology, ICF estimated that the region would need to build approximately 14 GW of new renewables and battery storage capacity to electrify NW Natural's load.

Q. Given the seriousness of the comprehensive energy system's needs during winter peak events, is NW Natural continuing to invest in the Mist Storage Facility to ensure its reliability?

A. Yes, it is absolutely critical to NW Natural's customers. The Direct Testimony of Daniel B. Kizer[14] discussed the Mist GC500 and GC600 Turbine Compressors Cold Spare Projects. These projects involve acquiring a gas generator, a power turbine and standby spare parts from Siemens for each of the GC500 and GC600 turbine compressor units for Mist at Miller Station.[15] These compressor units are essential to the reliability of Mist because both the GC500 and GC600 compressor units have exceeded their useful life expectancy, and both are necessary to ensure that natural gas can be reliably withdrawn during the winter season.[16]

[13] *See* Powerex, *Analysis of the January 2024 Winter Weather Event* at 2.

[14] NW Natural/500, Kizer/18-27.

[15] NW Natural/500, Kizer/22-23.

[16] NW Natural/500, Kizer/21.

Q. Is the Mist GC500 and GC600 Turbine Compressors Cold Spare Project a long-term solution for reliability at Mist?

A. No. As stated in Mr. Kizer's Direct Testimony,[17] the Mist GC500 and GC600 Turbine Compressors Cold Spare Project is necessary to ensure the immediate reliability of Mist. However, it does not address the long-term viability of the GC500 and GC600 units.[18] Namely, they have exceeded their operational lives, and failures and outages have already occurred.[19] The existing turbine compressors are not supported by the original equipment manufacturer ("OEM") and there are several core components that are no longer able to be sourced globally even with the OEM's support.[20]

These issues highlight the need for a robust long-term solution. NW Natural will replace the existing GC500 and GC600 compressors with new turbine compressors with an established and active supply chain, with parts readily available to support the operational needs of NW Natural and the needs of our customers.

Q. Given the importance of Mist, when does NW Natural anticipate replacing the GC500 and GC600 units?

A. NW Natural anticipates replacing the GC500 unit in 2025 and the GC600 unit in 2026. The Company will replace the GC500 unit first because it is the older unit

[17] NW Natural/500, Kizer/27.

[18] NW Natural/500, Kizer/27.

[19] NW Natural/500, Kizer/18-27.

[20] NW Natural/500, Kizer/20-22.

and will use the GC600 unit to support injection operations during this time. During the next injection season (2026), the Company will replace the GC600 unit and will use the replacement GC500 unit to support operations during this time.

The timeline to replace both these units is one year sooner than the Company originally anticipated. NW Natural had previously planned to replace these units in 2026 and 2027. However, as stated above, NW Natural experienced five record setting Mist withdrawal gas delivery days in January 2024, further emphasizing the importance of reliable natural gas storage to ensure that NW Natural can meet its customers' energy needs on the coldest days of the year. NW Natural will provide further updates on this project in the Company's Integrated Resource Plan ("IRP") Update filed in August 2024.

B. Decarbonizing the Natural Gas System

Q. NW Natural provided Supplemental Testimony following the invalidation of the Climate Protection Plan ("CPP") to provide updates to the Company's rate request based on the invalidation. Broadly speaking, does NW Natural remain committed to the decarbonization pathways you described in your Opening and Supplemental Testimony, even though the Oregon Court of Appeals has found the CPP to be invalid?

A. Yes. NW Natural remains committed to the decarbonization pathways including cost-effective energy efficiency, decarbonized fuels, and solutions that leverage the strengths of both the natural gas and the electric systems, such as hybrid heating and ground source heat pumps. In hybrid heating, a heat pump is paired with a gas furnace to help address continuing resource adequacy and reliability

concerns on the electric grid while reducing natural gas throughput. Hybrid systems leverage the strengths of both energy systems by utilizing the electric system in milder conditions, and relying on the gas system during colder weather when the electric system may have resource adequacy challenges and cannot depend on renewable power. Hybrid systems also eliminate the need to rely on higher emitting and more costly electric resistance heating during colder weather where an air source heat pump cannot adequately heat a home.

The Company is also exploring ground source heat pumps as another decarbonization solution. Individual ground source heat pumps provide heating and cooling to a single building, whereas networked ground source heat pumps ("geothermal energy networks") connect the individual ground source heat pumps within each building via a shared network of water pipes transferring heat in and out of those buildings that, when properly designed, leads to increased energy optimization. In its Washington state service territory, NW Natural is beginning to study the feasibility of geothermal energy networks in response to the passage of HB 2131 in late March 2024. HB 2131 permits Washington natural gas utilities to build such networks to serve customers in their respective service territories.

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Q. The Coalition argues that the Company is taking a business-as-usual approach to decarbonization.[21] Please respond.

A. NW Natural's approach is anything but "business-as-usual."[22] As already explained above, NW Natural is exploring ambitious decarbonization pathways that include increased energy efficiency, decarbonized fuels, and leveraging the strengths of both the natural gas and electric systems through hybrid heating and geothermal heat pumps. From a regulatory perspective, the Company is proposing a first-of-its kind LEA that supports the addition of low-use customers by providing an increasing LEA with lower anticipated natural gas use. This approach stands in clear contrast to the convention used in most states (and historically used by NW Natural) where a higher LEA is provided for higher-use customers. The inverted nature of the LEA is driven by the inclusion of incremental climate policy costs for each new customer that joins NW Natural's system. This approach balances the continued market demand for the performance and resiliency benefits of natural gas appliances in homes with the goal of reducing overall emissions.

NW Natural's pursuit of innovative decarbonization pathways coupled with new regulatory proposals to reduce throughput demonstrates that it is not pursuing a business-as-usual approach based on increasing energy demand.

[21] Coalition/100, Cebulko/17.

[22] Coalition/100, Cebulko/17.

Q. In arguing that NW Natural should focus on a single decarbonization pathway—electrification—the Coalition discusses IRPs extensively. Please summarize the Coalition's conclusions.

A. The Coalition states that the Commission did not acknowledge NW Natural's long-term plan to comply with the now invalidated CPP, citing the Commission's conclusion that the IRP's assumptions about the future cost of decarbonized fuels are optimistic.[23] Based on this Commission finding, the Coalition speculates that NW Natural will be unable to meet future Oregon greenhouse gas ("GHG") regulations without electrifying the vast majority of its current load, even though the Commission made no such conclusion in NW Natural's IRP.[24]

Q. How do you respond to the Coalition's assertions?

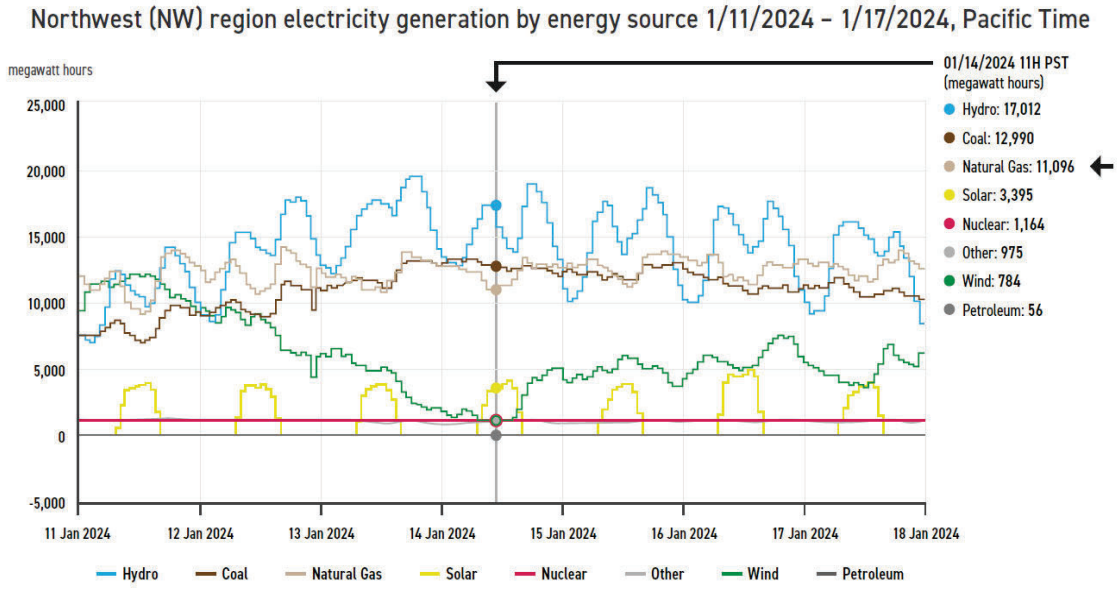
A. First, and perhaps most importantly, the Coalition ignores that there is a strong market demand for natural gas service. In other words, NW Natural's customers and prospective customers want natural gas. The Company continues to increase its customer base year-over-year. In response to that demand, home builders continue to include natural gas in new construction and, in fact, vocally supported natural gas at the Commission's public comment hearing on April 16, 2024.[25] None of this would occur if NW Natural's customers and prospective customers wanted all-electric homes.

[23] Coalition/100, Cebulko/14-15.

[24] Coalition/100, Cebulko/16-17.

[25] Staff/2200, Nottingham/3-4.

Second, the Coalition falsely equates electrification with decarbonization. As explained above, natural gas is essential to ensure the reliability of the electric grid and will be for the foreseeable future. In fact, the electric system is already struggling to decarbonize their *existing* power supply while maintaining reliability. This is why electric utilities heavily rely on natural gas use for power generation and certain Oregon utilities are extending the lives of their coal generation fleet. For example, the graph below from the United States Energy Information Administration Electric Grid Monitor for the Northwest region from January 11, 2024 through January 17, 2024 shows natural gas and coal generation remain heavily relied on in the winter.[26]



[26] U.S. Energy Information Administration, Hourly Electric Grid Monitor (last visited Jun. 2, 2024) (available at https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/regional/REG-NW).

Simply moving the entirety of NW Natural's winter peaking load to the electric grid will not result in decarbonization. Both the invalidated CPP and HB 2021 have aggressive decarbonization targets (90 percent reduction in emissions and a 100 percent reduction in emissions, respectively). Therefore, even assuming there are future GHG regulations for Oregon natural gas utilities—which we expect there to be—moving direct natural gas service load to the electric grid only serves to transfer the compliance obligation to another entity. Any load growth on the electric system would have to be met by entirely renewable resources to meet HB 2021 targets. In other words, shifting load from one energy provider to another energy provider does not eliminate emissions or compliance with climate policies; rather, it simply "squeezes the balloon" and makes the other side's emissions profile larger.

Nonetheless, the Company does not oppose coordinating with electric utilities to decarbonize, such as through hybrid systems or geothermal heat pumps. In fact, the Company is eager to collaborate with the region's electric utilities on such efforts. However, simply assuming that electric utilities can absorb the heating load currently served by NW Natural—the largest of any electric or gas utility in the state—is not technically supported, reasonable or prudent. Moreover, it ignores the very real resource adequacy constraints that electric utilities are already facing and does not recognize the capacity, reliability, and resiliency inherent in NW Natural's system to meet customer demand in extreme winter weather.

Q. Do you believe the Coalition correctly characterized IRPs and the IRP process?

A. No. Regarding NW Natural's IRP order specifically, the Company's commitment to near-term compliance with the now invalidated CPP was never in question. Rather, the issue was simply whether NW Natural should purchase Community Climate Investment ("CCI") credits or acquire RNG. Neither of these compliance paths are building electrification. The Commission believed that NW Natural should "pursue RNG and CCIs in the most economical way possible to minimize compliance costs and risks."[27] Prior to the Commission's order, NW Natural was reluctant to rely on CCI credits because they were never actually offered for sale. Moreover, as a GHG reduction tool it was unclear how they could actually achieve the state's decarbonization goals, which suggests they were inherently high risk in terms of actual emissions reductions.

While the Commission did not acknowledge NW Natural's long-term plan to meet demand and comply with the invalidated CPP, it must be noted that ***all*** Oregon investor-owned utilities—natural gas and electric—have failed to persuade the Commission that they have adequate plans to meet long-term decarbonization goals.[28] To be clear, NW Natural is not criticizing any other utility. After all, NW Natural also lacked a Commission-acknowledged long-term plan prior to the CPP's invalidation. Instead, this point is meant to illustrate the challenges associated with

[27] *In the Matter of Northwest Nat. Gas Co., dba NW Natural, 2022 Integrated Resource Plan*, Docket No. LC 79, Order No. 23-281 at 11 (Aug. 2, 2023).

[28] Idaho Power is not subject to HB 2021, Oregon's Clean Energy Plan.

deep decarbonization that all energy utilities face. Further, even if the Commission had acknowledged these plans, it does not mean that decarbonization is certain. Conversely, non-acknowledgement does not indicate that a utility will fail to reach a decarbonization target. IRPs do not result in a "set it and forget it" 20-year plan. Within the 20-year IRP planning period, any number of things can happen that radically change the nature of a plan. For this reason, IRPs are iterative and build on previous versions with an eye towards continuous improvement. NW Natural will continue to produce IRPs to comply with all applicable legal requirements, but the Commission's decision to not acknowledge certain aspects of its IRP in the face of new regulations is hardly unique to NW Natural nor does it mean that state decarbonization targets will not be met.

More troubling than whether an IRP or Clean Energy Plan is acknowledged is the Coalition's failure to recognize the capacity value of the natural gas system, especially considering the increasing stresses on the electric grid made even more apparent since our Direct Testimony was filed. By advocating solely for electrification, the Coalition ignores both the limitations of the electric grid and the benefits of the natural gas and electric systems working in tandem in the Pacific Northwest. Specifically, the capacity value of the natural gas system can be leveraged with intermittent renewable electric power to both decarbonize and ensure reliability of the overall energy system while minimizing costs.

Q. Do the electric utilities' Clean Energy Plans include any load increases resulting from the subsequent electrification of gas utilities load?

A. To the best of NW Natural's knowledge, neither electric investor-owned utility in NW Natural's service territory has included a material amount of new load in their Clean Energy Plans resulting from the electrification of gas utilities' existing load, in particular space-heating load. Any additional load would make compliance with HB 2021 even more difficult because it would increase both utilities' winter peak loads and that demand would have to be met with 100 percent renewable energy, especially because any such electrification would be in addition to rising data center and electric vehicle demand that is forecasted to grow in the coming years.

Q. The Coalition appears to frame decarbonization as a zero-sum game where natural gas utilities' load will be completely electrified. Is there a better way to approach decarbonization?

A. Yes. Joint system planning between natural gas and electric utilities can help address many of the issues that I have discussed. It can help address resource adequacy on the electric system during the winter peak, while also ensuring that both systems decarbonize by leveraging intermittent renewable electric generation to the greatest extent practicable through hybrid heating systems. Also, joint system planning can help the broader state economy by ensuring there is an adequate supply of energy available to industries looking to locate in Oregon while minimizing costs.

IV. CHANGES TO REGULATORY MECHANISMS

Q. Please summarize NW Natural's strategy for responsible and planful growth that you discussed in Direct Testimony.

A. In my Direct Testimony,[29] I discussed our strategy for responsible and planful growth. As I described above, the energy systems—both gas and electric—are evolving in a transformative time. NW Natural expects that customers will use less of our product through hybrid space-heating systems (e.g., electric heat pumps backed-up by gas furnaces), but customers will continue to rely on the gas system for the resiliency benefits of fireplaces, water heaters, cooktops, and back-up generators. While overall gas delivery throughput will decrease, the full strength of the system, including NW Natural's three on-system storage facilities, will continue to be vital during winter peaks. As such, the Pacific Northwest will need to continue to rely on the gas system during the coldest winter days of the year.

Q. Please briefly summarize NW Natural's proposed adjustments to its tariffed services that support its responsible and planful growth strategy.

A. Under its responsible and planful growth strategy, the Company proposed two main adjustments to our tariffed services:

Updated LEA: An updated LEA for new customers that is responsive to current direction and the changing nature of how customers are using our system, which derives a higher allowance for lower-use customers.

[29] NW Natural/100, Palfreyman-Kravitz/25-28.

New Customer Fixed Charge: An increased fixed charge for new residential premises joining the system on or after November 1, 2024, to reflect new customers' lower usage compared to our existing customer base, and thereby protecting against intraclass subsidies that would otherwise occur through the decoupling mechanism.

Additionally, as described in Section V of my Reply Testimony, NW Natural intends to submit multiyear rate plans to the Commission in subsequent general rate cases to promote smaller, more predictable rate changes, and administrative efficiency.

Q. Why is it important for NW Natural to have the flexibility to adopt these types of changes?

A. As a utility, NW Natural is solely responsible for managing its business and it takes that responsibility extremely seriously, and it has for 165 years. During this recent transition to a decarbonized economy, NW Natural must have the ability to adapt to changing conditions by pursuing new policies and initiatives, such as an updated LEA and a new residential premises fixed charge. These new policies and initiatives are grounded in the same sound economic principles that have always been used in ratemaking, while also reflecting underlying changes that are occurring during these transformative times, including new premises' lower natural gas use and the impact of future Oregon GHG regulations. NW Natural's business must be able to adapt to these changing circumstances. These adaptations should ultimately be approved by the Commission because they are based on sound

economic analysis that is consistent with NW Natural's current operating environment.

Q. Please further describe changes to the LEA that NW Natural is seeking in this docket.

A. As I said above, NW Natural is proposing an LEA for new residential customers that increases with lower natural gas use. When the CPP was invalidated, NW Natural stood by this methodology and did not go back to a traditional LEA that incentivizes increased throughput. Instead, the Company estimated future compliance costs of a hypothetical GHG regulatory program and developed a LEA based on sound economics. It also committed to continue to update the LEA in future proceedings to ensure that its assumptions remain valid. In developing this LEA proposal, NW Natural followed where the economics took us to ensure that there was no cross-subsidization between new and existing customers. Combining these policy initiatives with its efforts to decarbonize its system through energy efficiency, decarbonized fuels, and hybrid electric/gas heating solutions, the Company is moving forward towards a decarbonized future in a thoughtful and innovative way that offers the greatest opportunity for energy resiliency and reliability.

Q. Does NW Natural's revised LEA promote equity?

A. Yes. According to home builders at the Commission's public comment hearing on April 16, 2024, the Company's proposed LEA "will help[] control initial construction costs, provide[] energy options to homeowners, and support[] broader housing

market goals by making homes more affordable and appealing."[30] Making homes more affordable promotes equity, particularly in the current housing market where home prices have increased rapidly in recent years. Also, the nature of the Company's LEA, which increases with less natural gas use, incentivizes the installation of high-performing and resilient natural gas appliances that can provide heating even in the event of a power outage. These widespread winter power outages are an unfortunate occurrence in our service territory. The Company's proposal will help ensure that these appliances are not just for those wealthy enough to afford line extension construction costs without any such allowance.

Q. Please describe NW Natural's modifications to the LEA proposed in its Reply Testimony.

A. In reviewing testimony from Staff, NW Natural is adjusting two inputs to its methodology to determine the LEA. First, Staff criticized the cost of the RNG assumed for the 25-year duration of the discounted cash flow ("DCF") model. The Company utilized a conservative assumption of $22.00 per dekatherm for all incremental volumes driven by new residential customers. Despite this amount being more conservative than the costs included in NW Natural's most recent IRP, NW Natural further increased the costs of RNG through the 25-year period of the DCF model from $22.00 per dekatherm to $25.00 per dekatherm. This value per dekatherm should provide any needed comfort as to the veracity of the model, and

[30] Staff/2200, Nottingham/3.

the value can be adjusted as better projections of future compliance costs become available.

Second, NW Natural is updating how it calculates the benefit that each new customer brings to the Company's fixed capital costs. Certain capital investments will be made regardless of the growth on the system, and the ability to spread those costs over a larger customer base is an important determinant when evaluating the costs and benefits that each new customer brings to the gas system. Through the rate case process, Staff challenged whether enough capital expenditures associated with permitting and meters for new construction (i.e., growth-related investments) were excluded from the non-growth capital forecast. This second update addresses this issue.

Third, while not necessarily a change currently being made in response to Staff, NW Natural intends to update the LEA to reflect the final revenue requirement in this rate case. LEA calculations are, in part, driven by the expected revenues that a customer will generate. To the extent that the revenue requirement ultimately decreases, the LEA would appropriately capture that decrease.

Q. What is the outcome of the LEA based on the two proposed changes described above?

A. As shown in the table below, the proposed changes to the forecasted price of RNG and non-growth capital expenditures reduce the LEA by several hundred dollars. The exact amount varies based on usage tier. After the final revenue requirement

is established in this rate case, NW Natural will make a further update to account for any resulting changes to the LEA, as explained above.

Revised LEA Results

UPC (Therms)	0-250	251-450	451-650	651+
Direct Testimony LEA	$3,600	$3,100	$2,600	$1,800
Supplemental Testimony Proposal	**$3,700**	**$3,300**	**$2,950**	**$2,200**
Revised LEA	**$3,400**	**$2,900**	**$2,500**	**$1,700**
Difference: Higher / (Lower)	**($300)**	**($400)**	**($450)**	**($500)**

The Reply Testimony of Gregg H. Therrien (NW Natural/4000, Therrien) further responds to parties' positions regarding the LEA.

Q. Please describe the higher fixed charge for new residential premises.

A. NW Natural is proposing a higher monthly fixed charge of $26.25 for new single family residential premises added to NW Natural's system, and a fixed charge of $24.25 for new multifamily premises.[31]

Q. Why is NW Natural proposing a higher fixed charge for new residential premises?

A. As further explained in the Reply Testimony of Robert J. Wyman (NW Natural/3900, Wyman), a new residential premises is a customer that connects to NW Natural's system after November 1, 2024. An average new premises residential customer is forecasted to use 449.4 therms on a weather normalized basis. In comparison, an average existing residential customer is forecasted to

[31] The $2 difference between new single family and multifamily residential premises is due to the comparatively lower cost of service for multifamily dwellings. NW Natural/3900, Wyman. As explained in NW Natural/3900, Wyman, the precise amount of the fixed charge is dependent on the final revenue requirement in this proceeding.

use 660.2 therms on a weather normalized basis. New premises use less natural gas because, on average, these premises are more energy efficient and have newer, more efficient appliances. This large disparity in average forecasted use is the driving force behind NW Natural's proposed higher fixed charge for new premises.

Q. Please explain how this large disparity in use between new premises and existing customers is the driving force behind NW Natural's higher fixed charge.

A. Under the Company's existing decoupling mechanism, all residential customers are decoupled to a single baseline that reflects an average existing residential customer's use on a weather normalized basis. Since new premises use less natural gas than projected in the baseline, these new premises customers do not pay the amount of money that is forecasted in the decoupling mechanism based on this current use per customer ("UPC") baseline. Instead, the shortfall must be recovered through the volumetric decoupling deferral. This amount is recovered through the volumetric rate charged to all residential customers, resulting in existing residential customers paying more than new premises residential customers because they use more natural gas.

Q. How does the Company propose to address this cross-subsidization?

A. NW Natural proposes two changes. First, NW Natural proposes to establish separate decoupling baselines for new premises and existing residential customers. The new premises decoupling baseline will be set at the expected annual weather normalized forecasted use (449.4 therms). The existing

customers' baseline will be set at 660.2 therms, reflecting their expected annual weather normalized forecasted use.

Second, NW Natural proposes a higher monthly fixed charge for new premises customers due to the lower decoupled baseline.[32] Without any modification to rate design, NW Natural will collect less money from new premises residential customers because, again, their natural gas use is lower, but their cost to serve—compared to an existing customer—is the same. This shortfall would otherwise be recovered through the volumetric decoupling deferral, which, as explained above, is disproportionally recovered from higher-use existing residential customers through the volumetric rate. NW Natural's proposed higher fixed charge, however, would prevent such a shortfall, thereby preventing higher-use existing customers from subsidizing new premises.[33]

Q. Does NW Natural's higher fixed charge for new premises promote equity?

A. Yes. As further explained in the Reply Testimony of Robert J. Wyman (NW Natural/3900, Wyman), new premises customers are generally in energy efficient homes with new appliances that already have lower gas use. Existing customers may not have these advantages and, therefore, should not be expected to subsidize new customers. More specifically, new premises customers are, on average, more likely to live in higher-income Census Tracts, are more likely to be owners of newly constructed single-family residences and are less likely to be

[32] NW Natural/3900, Wyman.

[33] NW Natural/3900, Wyman discusses these issues in greater detail.

enrolled in the Company's bill discount program compared to existing premises customers. Also, as stated above, without any change to rate design, any shortfalls in cost recovery from new premises customers will be recovered through the residential volumetric rate that will disproportionally impact higher use existing premises customers.

Q. Did NW Natural consider any other approaches besides the higher fixed charge for new premises?

A. Yes. Instead of a higher fixed charge, NW Natural considered a higher volumetric charge for new premises. However, NW Natural believes a higher fixed cost is more equitable because it spreads out the cost of natural gas over the course of the year, which reduces month-to-month volatility in bills. In arguing against the fixed charge for new premises, the Coalition states that NW Natural's proposal moves away from the existing decoupling methodology in favor of a new policy framework for fixed cost recovery that heavily relies on fixed charges.[34] However, the Coalition overlooks the seasonal variability in natural gas bills and how higher fixed charges can smooth out customers' costs over the course of the entire year, especially during cold weather events when space-heating usage can have a significant impact on bills. More importantly, however, NW Natural is moving away from its existing decoupling methodology precisely because it leads to existing customers subsidizing new premises residential customers, which the Coalition (and every other party) should seek to prevent and not minimize its importance.

[34] Coalition/100, Cebulko/49.

The Reply Testimony of Robert J. Wyman (NW Natural/3900, Wyman) further responds to parties' positions regarding the higher fixed charge for new premises.

V. ADDRESSING AFFORDABILITY CONCERNS

Q. Please explain what actions NW Natural has taken to mitigate the impact of its proposed rate increase on customers.

A. In this rate case, NW Natural proposed to enhance its bill discount program to further address the needs of our lower income customers. Specifically, we proposed to increase the discounts offered to address and mitigate the energy burden experienced by these customers. Based on the rate request filed in this rate case, the Company recalibrated the income eligibility in two of the four income tiers with the goal of minimizing a customer's energy burden to less than half of the six percent of a household's income that is commonly understood as the indicator of energy-burdened customers. This is further described in the Direct and Reply Testimony of Cecilia J. Tanaka (NW Natural/200, Tanaka and NW Natural/2300, Tanaka).

At the same time, however, NW Natural must maintain a safe and reliable system to meet customer demand. NW Natural is seeking to increase rates due to higher operating costs from inflation and to recover the costs of long planned investments. Although CUB appears to question the timing of NW Natural's seismic-related investments,[35] the Company views them as essential in order to

[35] CUB/100, Jenks/6.

provide a safe workplace for all of its employees and to be as well positioned as possible to continue to provide safe and reliable service in the aftermath of a major earthquake. Since no one knows when such an earthquake will occur, NW Natural cannot delay these crucial investments, but rather must act to protect its employees and its customers, as well as the general public.

Q. In its Opening Testimony, did Staff express concerns about the affordability of utility rates in general?

A. Yes. Staff expresses concerns regarding the impact to residential customers of both utility rate increases in general and NW Natural's proposed rate increase in particular. Staff states that it "may constitute an unreasonabl[e] energy burden for NW Natural's Oregon utility customers outpacing Oregon wages."[36]

Q. What is your initial response to Staff's concerns?

A. NW Natural takes these concerns very seriously. Staff states that food company executives have said that "shoppers will adjust over time to higher [food] prices, as they have in the past," and cautions NW Natural from adopting this type of mentality to cost control.[37] In running its business, NW Natural assures Staff that it does not subscribe to this view, nor has it managed its business assuming that customers will simply "adjust" to higher bills. In fact, even with this proposed rate increase, the average NW Natural residential customer bill is 7.7 percent lower than it was 15 years ago after adjusting for inflation. While we recognize that any

[36] Staff/100, Muldoon/8.

[37] Staff/100, Muldoon/8-9.

rate increase may be a hardship for certain customers, we must invest to ensure reliable and safe service.

Q. Did CUB also address affordability in its testimony?

A. Yes. CUB has proposed a rate shock mitigation mechanism in NW Natural's rate case.[38] This mechanism involves 1) Deferring or phasing in the rate increase—with or without carrying charges; 2) Setting the return on equity ("ROE") at a level that is not lower than the lowest reasonable rate; and 3) Requiring the utility to propose and implement other rate mitigation measures.[39]

Q. As a threshold matter, has the Commission ever implemented any of these measures in a manner suggested by CUB?

A. No. Even though a former Commissioner articulated these general principles more than 20 years ago, Mr. Jenks' testimony acknowledges that the Commission has never done what CUB is suggesting here—adopt a one-size-fits-all approach that would apply to all energy utilities.[40]

Q. How does CUB propose to determine whether to defer or phase-in a rate increase?

A. CUB recommends that the Commission adopt a similar mechanism that is used to limit rent increases in the state of Oregon for units that are more than 15 years old.

[38] CUB/100, Jenks/6-12. CUB made the same proposal in Idaho Power's recent general rate case. See *In the Matter of Idaho Power Co., Request for a General Rate Revision*, Docket No. UE 426, CUB's Opening Testimony, CUB/100, Jenks/9-15 (Mar. 25, 2024).

[39] CUB/100, Jenks/6, 8-12.

[40] CUB/100, Jenks/5.

Generally speaking, this mechanism limits rent increases for such housing to the lower of 10 percent, or 7 percent plus the Consumer Price Index.[41]

Q. Does NW Natural agree with CUB's proposal?

A. No. The proposal ignores substantial differences in how utilities are regulated compared to the rental housing market. Unlike rental housing, utilities are subject to cost-of-service regulation, which limits utilities' cost recovery to their prudently incurred costs approved by the Commission. In return for being subject to Commission regulation, utilities receive the exclusive right to serve customers in a given area. The same is not true of the rental housing market where rents are set based on supply-and-demand. In situations where the demand for rental housing exceeds supply, landlords may increase their rent, even if there is no commensurate increase in the costs they incur to make such rental housing available to the market. In such a market, landlords would have the opportunity to increase their profits to whatever the market may bear. Regulated utilities cannot take similar actions. Instead, their rates reflect the cost to serve customers, and are closely regulated by the Commission.

This distinction between utilities and rental housing (or any non-regulated market) is key to understanding why CUB's proposal is inappropriate. Deferring or delaying rate increases prevents utilities from timely recovering prudently incurred costs that are necessary to provide essential services. It is also contrary to the regulatory compact where utilities agree to economic regulation by the

[41] CUB/100, Jenks/7-8.

Commission in exchange for the opportunity to timely recover prudently incurred costs and for an exclusive service area.

Q. Are there other issues with CUB's definition of a rate mitigation trigger?

A. Yes. Under its proposal, CUB states that "if inflation is 3%, then the trigger [for rate mitigation] is 10%."[42] The problem with this approach is that it simply compares present rates with proposed rates, ignoring the fact that NW Natural's rates go up and down over time. In 2023, for example, NW Natural's residential rates declined by 9 percent. In determining whether rates should be mitigated for 2024, however, CUB's proposal would not take that 2023 rate decrease into account. Instead, it would simply compare current rates to rates that would go into effect November 1, 2024. Using CUB's example of a 10 percent rate mitigation "trigger," NW Natural's rates would be subject to mitigation if its overall 2024 rate increase is 11 percent. This result hardly constitutes "rate shock," however, because NW Natural's rate increase over the 2023-24 period would be approximately 2 percent (i.e., the 11 percent increase is offset by the 9 percent decrease the year before), below the inflation amount in CUB's example. Taking a broader view, an average residential customer's bill has decreased by 7.7 percent compared to 15 years ago after adjusting for inflation. This fact, alone, indicates that a prescriptive one-size-fits-all approach to affordability suggested by CUB is inappropriate and should be rejected by the Commission.

[42] CUB/100, Jenks/14.

Q. Is NW Natural using the stability of residential customer bills over the last 15 years as a reason to increase rates?

A. No. NW Natural does not dispute that it is seeking a substantial rate increase. Rather, we point out the Company's history of relative rate stability because it provides relevant context, especially given the concerns raised by CUB and Staff. We recognize that not all households and businesses have natural gas service, and customers have other options for serving their energy needs. This means that, even as a regulated utility, we compete for business with other energy providers, and therefore, we are always motivated to keep natural gas rates as low as possible while still being able to provide excellent customer service, comply with safety standards, and maintain financial integrity as a Company.

Q. CUB acknowledges that an issue with its proposal is that it may lead to more frequent general rate proceedings. Do you view that as another problem with the proposal?

A. Yes. CUB acknowledges that one way to mitigate the impact of its rate mitigation trigger is to file annual general rate cases.[43] For example, over a two-year timespan, a utility could file for back-to-back 7.5 percent rate increases instead of one 15 percent increase at the end of the two-year period that would likely trigger the cap. As CUB suggests,[44] it would increase the administrative burden on the Commission, the utility, and all other parties to process utility rate cases on an

[43] CUB/100, Jenks/15.

[44] CUB/100, Jenks/16-17.

annual basis. Moreover, since CUB's proposal would apply to all energy utilities in Oregon, not just NW Natural, this burden would likely be substantial.

Q. CUB proposes to move the rate effective date of this proceeding to April 1, 2025.[45] How does the Company respond?

A. This proposal should be rejected. First, CUB's proposal ignores Oregon law requiring the Commission to determine whether a public utility's proposed rates are fair, just and reasonable within 10 months of a public utility's request to change its rates.[46] This proposal also denies public utilities' cost recovery of prudently incurred costs. These issues will be further detailed in the Company's legal briefing.

Second, CUB's proposal encourages multiple rate changes in a single year, which sends confusing price signals to NW Natural's customers. CUB's position is contrary to prior statements from CUB about the timing of NW Natural's rate cases. In NW Natural's last rate proceeding, CUB stated:

> Over the past ten years, most of NW Natural's rate change due to the PGA and GRCs have occurred on November 1st. **CUB appreciates the Company's policy of minimizing the frequency of rate changes born[e] by customers, and is making that proposal to continue that policy**.[47]

NW Natural agrees with CUB's prior statements and will continue to aim to minimize rate changes throughout the year.

[45] CUB/100, Jenks/15.

[46] ORS 757.210(1)(a) (requiring rates be fair, just, and reasonable); ORS 757.215(1) (authorizing the Commission to order the suspension of rates "for a period of up to nine months").

[47] Docket No. UG 435, CUB/500, Gehrke/20 (Jul. 27, 2022) (emphasis added).

Q. Is the Company flatly opposed to rate mitigation measures?

A. No. NW Natural recognizes that there are circumstances where rate mitigation may be warranted. As mentioned above, NW Natural is proposing to increase assistance under its bill discount program to limit natural gas-related energy burden to no more than three percent. Also, in extreme situations, such as when NW Natural's bills increased 25 percent due to both a PGA adjustment and a rate case in 2022, NW Natural worked with CUB and other stakeholders to phase-in such a rate increase. But, again, CUB's proposed rate mitigation trigger would be far lower than that amount and ignores other pertinent facts that must be considered, such as NW Natural's 9 percent residential rate decrease in 2023 and that, after adjusting for inflation, customers' bills are lower than they were in 2009.

Q. CUB also suggests setting the ROE at the lowest reasonable rate.[48] Does NW Natural support this proposal?

A. No. CUB has again ignored Oregon law, which states:

> The commission shall balance the interests of the utility investor and the consumer in establishing fair and reasonable rates. Rates are fair and reasonable for the purposes of this subsection if the rates provide adequate revenue both for operating expenses of the public utility . . . and for capital costs of the utility, with a return to the equity holder that is:
>
> (a) Commensurate with the return on investments in other enterprises having corresponding risks; and
> (b) Sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital.[49]

[48] CUB/100, Jenks/15.

[49] ORS 756.040(1).

The Commission is required by law to ensure that a return is fair and reasonable. Each public utility will have unique circumstances that the Commission must consider when making this evaluation. The Commission should not summarily decide these issues without considering these factors. This issue will be further detailed in the Company's legal briefing.

Q. In arguing for setting the ROE at the lowest reasonable amount, CUB argues that "[m]ost businesses compete in competitive markets, where customers have other options" and that "[i]f that business sets a price that is too high for its product, then customers will go elsewhere, and profits will fall." Therefore, utilities should be subject to "similar market discipline" by setting the ROE at its lowest reasonable amount.[50] What do you think of CUB's view?

A. NW Natural disagrees with this view. While NW Natural is a public utility subject to the regulatory compact in Oregon, natural gas is a fuel of choice, and customers have other options for the provision of their energy service. Unlike electric utilities, there is no certainty that new homes will be built with natural gas appliances. In this way, natural gas utilities have always faced acute competitive pressures compared to electric utilities. Further, CUB's Opening Testimony regarding NW Natural's LEA proposal speculates, albeit without analysis, that natural gas service is becoming less cost competitive.[51] Therefore, it appears that even CUB

[50] CUB/100, Jenks/10-11.

[51] CUB/200, Garrett/19.

concedes that NW Natural is subject to competition and the "market discipline" it seeks already exists for the Company. Yet we must continue to attract capital and make investments in order to continue to offer safe and reliable natural gas service. CUB's proposal would make that more difficult, which, over time, will likely increase the cost to customers.

Q. CUB proposes a number of other requirements that it wants NW Natural to adhere to, in order to mitigate the rate increase. What are they?

A. First, CUB states that the Company should be required to submit a plan to the Commission outlining what it is doing to mitigate the rate increase, including increasing outreach efforts to educate customers about its bill discount program, equal pay, energy efficiency and other options that might help the customer deal with the impact. Second, for 12 months after the rate effective date, CUB argues that NW Natural be required to report to the Commission, by zip code, the number of customers who have 30-day arrearages, the number that have 60-day arrearages, the number that have received shut off notices, the number that have been shut off, the number that are on payment plans, and the number that are on equal payment plans. Finally, CUB suggests that a shut off moratorium should be implemented for a 6-month period (November 1 to May 1), "allowing customers some time to manage the increase."[52]

[52] CUB/100, Jenks/15.

Q. How does NW Natural respond to CUB's reporting requirements?

A. First, NW Natural has a significant outreach plan for its bill assistance programs as explained in the Reply Testimony of Cory A. Beck (NW Natural/3200, Beck) and Cecelia J. Tanaka (NW Natural/2300, Tanaka). The Reply Testimony of Cecelia J. Tanaka (NW Natural/2300, Tanaka) also explains why CUB's proposed rate mitigation reporting requirements are an inefficient use of Commission, stakeholder, and Company resources. Second, with respect to the other reporting requirements, NW Natural has provided data similar to the requested data during the COVID-19 pandemic. If this data would be useful to the Commission and stakeholders, NW Natural will explore this more with parties to the case.

Q. Does NW Natural support a shut off moratorium from November 1 to May 1?

A. No. Changes to Division 21 rules that help to mitigate energy burden and provide a safety net to prevent disconnections for non-payment implemented by NW Natural already include expansion of the cold weather moratorium parameters for all customers, limitations on field and reconnection fees and no late payment fees for low-income customers. In addition, as indicated in the Reply Testimony of Cecelia J. Tanaka (NW Natural/2300, Tanaka), NW Natural has analyzed and demonstrated our review of the current tools available to help mitigate rate changes and energy burden. That analysis showed that we are continuing to have effective mitigation tools to help reduce energy burden, thus helping to insulate the impacts of rate changes on customers most in need.

Q. CUB suggests that the Commission could order the Company to suspend or reduce the amortization of certain deferred accounts or other single issue ratemaking mechanisms, to reduce the impact of the rate increase.[53] Do you support this proposal?

A. No. NW Natural is not sure how CUB's proposal would be implemented or what deferred accounts it would affect. More importantly, however, NW Natural does not believe that its recent rate proposal results in rate shock that must be mitigated by unprecedented Commission action.

Q. Your testimony strongly pushes back against CUB's proposals. Does this mean that NW Natural is against any proposal to mitigate rate increases?

A. Not at all. NW Natural believes that many of CUB's goals can be met through multi-year rate plans, which would provide parties with a more holistic view of costs over an extended period of time. Having this type of transparency can allow parties to craft solutions to mitigate rate increases over the period of the plan, although NW Natural acknowledges that there would be some uncertainty regarding commodity costs that are recovered through the annual PGA.

Q. Please summarize your prior testimony on NW Natural's intention to propose a multi-year rate plan.

A. As is discussed in Direct Testimony, NW Natural is in the process of developing a proposal for the Commission to approve a multi-year rate plan, which would set rates for a period of two to four years in advance with rate changes set to take

[53] CUB/100, Jenks/11.

effect incrementally each year.[54] A multi-year rate plan has the potential to create predictability for customers, mitigate lumpy rate increases, eliminate strain on Commission resources, and reduce regulatory lag for the Company. Though there are many benefits to a multi-year rate plan, NW Natural anticipates that this approach will require input from Staff and intervenors, so it has introduced this concept in the current rate case as an opportunity to begin the conversation on issues that will be pertinent to adopting a functioning multi-year rate plan leading up to the Company's eventual proposal.

Q. Is NW Natural proposing a multi-year rate plan in this rate case?

A. No, the Company is not proposing a multi-year rate plan in this docket; however, the Company is planning to propose a multi-year rate plan in its next rate case.

Q. Does the Company intend that a multi-year rate plan will be based on cost-of-service ratemaking?

A. Yes. It appears there may have been confusion on this point, because in discovery, Staff referred to a "hybrid multi-year rate plan" and asked NW Natural to indicate how it is superior to cost-of-service ratemaking. However, NW Natural does not intend to propose a "hybrid multi-year rate plan" and wishes to clarify Staff's terminology. As discussed above, the Company's proposal is intended to be a multi-year rate plan that establishes incremental rate increases over a period of two to four years. In addition, the Company is not suggesting that a multi-year rate plan is superior to cost-of-service rates because these are not opposing

[54] NW Natural/100, Palfreyman-Kravitz/32-33.

concepts. Rather, the multi-year rate plan will be developed using cost-of-service ratemaking but would apply this concept to establish rates over a pre-defined period of years.

Q. What benefits do multi-year rate plans provide to customers?

A. A multi-year rate plan will benefit customers by creating rate stability over the duration of the plan, smoothing out rate impacts to customers. Additionally, with a multi-year rate plan, it is less likely that the Company would need to seek a large increase in rates in a particular year, reducing the potential for rate shock.

Q. How do the Commission, Staff, and NW Natural benefit from multi-year rate plans?

A. Without a multi-year rate plan, NW Natural anticipates it will need to file multiple rate cases in the short term to address increasing costs associated with decarbonization, modernizing network security, and maintaining a safe and reliable natural gas system. If NW Natural were permitted to establish a multi-year plan, the Commission and its Staff will be able to conduct structured review processes during the duration of the multi-year rate plan to assess prudence without conducting a time-consuming general rate case, allowing the Commission to focus its resources on other proceedings. NW Natural anticipates a multi-year rate plan will decrease the workload for the Commission and Staff.

Q. Did Staff have any other concerns reflected through its DRs?

A. Yes, Staff sought to understand the types of multi-year rate plans that NW Natural is reviewing as examples for crafting its multi-year rate plan proposal.

Q. What is NW Natural using as a reference for its multi-year rate plan proposal?

A. NW Natural expects to leverage its own experience in creating a two-year rate plan in Washington as a guide for its Oregon proposal. NW Natural also expects to learn from its Washington peer utilities in developing a fair and balanced multi-year rate plan for Oregon. For example, NW Natural is aware of Avista Corporation ("Avista"),[55] Puget Sound Energy ("PSE"),[56] and PacifiCorp[57] two-year rate plans in effect in Washington that the Company will also likely reference in constructing its Oregon rate plan. Further, Avista,[58] PSE,[59] and Cascade Natural Gas Corporation[60] have filed new two-year multi-year rate plans in 2024 currently awaiting approval by the Washington Utilities and Transportation Commission ("WUTC"). NW Natural expects its Oregon multi-year rate plan to cover a period

[55] *Wash. Utils. and Transp. Comm'n v. Avista Corp., dba Avista Utils.* and *In the Matter of the Electric Service Reliability Reporting Plan of Avista Corporation dba Avista Utilities*, WUTC Docket Nos., UE-220053, UG-220054, UE-210854, Final Order No, 10-04 at 2 (Dec. 12, 2022) (adopting a settlement providing for a two-year multi-year rate plan).

[56] *Wash. Utils. and Transp. Comm'n v. Puget Sound Energy*, WUTC Docket No. UE-220066, Final Order No. 24 at 1 (Dec. 22, 2022) (approving a settlement agreement that contains a two-year rate plan).

[57] *Wash. Utils. and Transp. Comm'n v. PacifiCorp dba Pacific Power and Light Co.*, WUTC Docket No. UE 230172, Order No. 08 at 1 (Mar. 19, 2024) (adopting a partial multi-party settlement that provides for a two-year rate plan).

[58] *Wash. Utils. and Transp. Comm'n v. Avista Corp., dba Avista Utils.*, WUTC Docket No. UE-240006, Initial Filing Cover Letter (Jan. 18, 2024) (proposing a two-year rate plan with rates to take effect in December 2024 and December 2025).

[59] *Wash. Utils. and Transp. Comm'n v. Puget Sound Energy*, WUTC Docket Nos. UE-240004, UG-240005, Initial Filing Cover Letter at 1 (Feb. 15, 2024) (requesting updates to electric and natural gas rates for its two-year multi-year rate plan).

[60] *Wash. Utils. and Transp. Comm'n v. Cascade Natural Gas Corporation*, WUTC Docket No. UG-240008, Initial Filing at 1 (Mar. 29, 2024) (proposing a two-year rate plan with proposed increase at the start of year two).

longer than two years and is developing ideas for this unique aspect of its Oregon proposal.

Q. Although the Oregon proposal is in its infancy, how does NW Natural expect the Commission would set the rate base for each year of the multi-year period?

A. NW Natural expects that rates would be set to take effect each year on November 1. For the first year of the multi-year rate plan, rates would be set as they currently are using Oregon's forward test year. Subsequent years would be set using a capital forecast with reliable categories of anticipated expenditures, such as public works, vehicles and equipment, or transmission and distribution integrity management. For larger, discrete projects, NW Natural would specifically identify and justify these projects, their projected costs, and expected in-service dates. Similarly, reductions in costs associated with capital projects would also be captured in the rate plan, including accumulated depreciation and asset retirements.

O&M expenses for subsequent years of the rate plan would be tied to inflation and increase each year. To the extent inflationary pressures were tied to an index such as the Consumers Price Index ("CPI"), the costs could be updated prior to changing rates each year based on the most recently available CPI report. If there was a known and measurable event for a particular O&M expense, NW Natural would specifically justify it, similar to larger, discrete projects.

Q. What obligation would NW Natural have to provide updates to support rate increases during the multi-year period?

A. NW Natural proposes to make an update filing on or before July 1 of each year following the first rate effective date. For capital investments, NW Natural would make a filing each year demonstrating that the anticipated projects were placed in service prior to the upcoming rate effective date. For larger, discrete projects, NW Natural will provide updates on any changes in costs, scope or timing of the project. As noted above, for O&M costs, NW Natural will update these costs for the most recent CPI report. Staff and intervenors would have several months to review and conduct discovery prior to the revised rates going into effect on November 1 for each year of the plan.

Q. Did any party submit Opening Testimony discussing multi-year rate plans?

A. Yes, CUB indicated that it could support elements of a multi-year rate plan.[61]

Q. Please summarize CUB's view of multi-year rate plans.

A. CUB expresses skepticism of a utility driven process to develop multi-year rate plans, but also indicates that it could support a multi-year rate plan "for the sake of regulatory efficiency."[62] Specifically, CUB indicates that is could support a multi-year rate plan where a revenue requirement or ROE is set during the first year of the rate plan and the Commission and parties are tasked with reviewing investments and other discrete items in a subsequent year of the rate plan.[63] CUB

[61] CUB/100, Jenks/17.

[62] CUB/100, Jenks/17.

[63] CUB/100, Jenks/17.

further states that it was supportive of automatic annual rate changes used in the 1990s and could be supportive of a similar approach to ratemaking that would limit the issues raised in a rate case.[64]

Q. What is your response to CUB's view of multi-year rate plans?

A. The Company is encouraged that CUB sees benefits in a potential multi-year rate plan and agrees that one of the major benefits of such approach is the reduction of issues that are litigated in a rate case and the frequency of major rate case filings. The Company agrees that multi-year rate plans can smooth out the volatile annual rate increases that can result from large rate cases filed every few years following the traditional rate case model. As the Company indicated in its Direct Testimony, multi-year rate plans offer benefits to the Commission and intervening parties through a more efficient regulatory process while also providing benefits to customers through more certainty as to their rates.

VI. SUMMARY OF WITNESSES

Q. Can you briefly describe the testimony provided by other witnesses in this case?

A. Twenty-one other witnesses or panels of witnesses reply to the testimony of Staff and intervenors.

Cecelia J. Tanaka, Energy Equity and Affordability Lead, responds to Staff's and intervenors' testimony regarding equity and inclusion, including concerns regarding NW Natural's proposed enhancements to the bill discount

[64] CUB/100, Jenks/16-17.

program targeting reduced energy burdens for customers most in need, the Company's Oregon Low Income Energy Efficiency Program ("OLIEE"), and the Low-Income Needs Assessment ("LINA") that the Company conducted. NW Natural/2300, Tanaka.

Brody J. Wilson, Interim Chief Financial Officer, Vice President, Treasurer, Chief Accounting Officer and Controller, provides testimony about the Company's capital structure. In response to AWEC's proposed 52 percent debt and 48 percent equity structure, Mr. Wilson explains why a 50/50 capital structure is appropriate. NW Natural/2400, Wilson.

James M. Coyne, Senior Vice President, and **Jennifer E. Nelson**, Assistant Vice President, of Concentric Energy Advisors, Inc., a firm with expertise on utility finance and required rates of return for regulated companies, respond to testimony by Staff and intervenors concerning NW Natural's cost of equity, or in other words, the return that investors in NW Natural should reasonably expect to have the opportunity to earn. Their Reply Testimony provides an analysis of Staff's and AWEC's cost of equity analysis, as well as responding to general concerns raised by CUB and the Coalition. After their review of Staff's and intervenors' testimony and updated ROE analysis, Mr. Coyne and Ms. Nelson continue to recommend that NW Natural be allowed an opportunity to earn a 10.1 percent return on equity in the revenue requirement authorized in this proceeding. NW Natural/2500, Coyne-Nelson.

Daniel B. Kizer, Engineering Senior Director, responds to Staff's and AWEC's testimony concerning the status of projects described in his Direct

Testimony,[65] and to attestation processes suggested by Staff and AWEC to ensure that certain projects (i.e., distribution and storage, facilities and IT&S) are used and useful prior to the rate effective date. NW Natural/2600, Kizer.

Wayne K. Pipes, Director of Facilities, Security and Emergency Management, provides updates on the projects discussed in his Direct Testimony.[66] Additionally, he responds to Staff's testimony, which does not question the prudence of any project, but requests attestations for those projects entering service near the rate-effective date, and responds to CUB's testimony that the Company should reconsider its plans to perform seismic resiliency and office construction projects to attempt to slow rate increases. NW Natural/2700, Pipes.

Dina L. Thompson, Director of Enterprise Applications, explains why it is appropriate to allow recovery of cost contingencies for major IT&S projects subject to a final true-up before projects enter rates, provides an update on the Company's major IT&S projects, explains why the Company's hiring of all eight new full-time equivalent ("FTE") positions necessary to fill critical gaps in IT&S staffing should be recovered in rates, and responds to Staff's other requests not associated with a specific rate adjustment. NW Natural/2800, Thompson.

Matthew P. Carlson, Cybersecurity and Compliance Director, provides an update on the Company's cybersecurity efforts. NW Natural/2900, Carlson (Sensitive Security Information).

[65] NW Natural/500, Kizer.
[66] NW Natural/600, Pipes.

Joe S. Karney, Vice President of Engineering and Utility Operations, provides updates on the Company's Meter Modernization Program and responds to Staff's testimony regarding the program. NW Natural/3000, Karney.

Melinda B. Rogers, Vice President, Chief Human Resources and Diversity Officer, responds to Staff's proposed adjustments for officer and non-bargaining unit ("NBU") employee base pay and pay-at-risk, as well as the number of FTEs. In addition, Ms. Rogers explains the terms of the Company's new collective bargaining agreement ("CBA") with its Bargaining Unit ("BU") employees. NW Natural/3100, Rogers.

Cory A. Beck, Director of Customer Experience Services, responds to Staff's and the Coalition's recommended adjustments to NW Natural's proposed test year Category A and Category B advertising expense. In addition, he responds to the Coalition's testimony regarding the Company's marketing of the bill discount program and investment in multi-lingual outreach. NW Natural/3200, Beck.

Kathryn M. Williams, Vice President, Chief Public Affairs and Sustainability Officer, provides relevant background regarding political activity or lobbying expenses and direction from Commission Order No. 22-388 in the Company's most recent general rate case, docket UG 435, as it applies to this general rate case. In addition, she responds to Staff's recommendation regarding political activity/lobbying expenses and responds to the Coalition's recommended adjustments for political activity/lobbying expenses. NW Natural/3300, Williams.

Brody J. Wilson and **Nikki R. Sparley**, Treasury and Investor Relations Director, responds to Staff's and CUB's concerns regarding the Company's proposed uncollectible rate. They describe why the Company's proposed uncollectible rate is appropriate. NW Natural/3400, Wilson-Sparley.

Tobin F. Davilla, Senior Manager of Financial Planning and Budget, responds to a number of proposed operations and maintenance adjustments proposed by Staff and intervenors. NW Natural/3500, Davilla.

Zachary D. Kravitz and **Kyle N. Griffiths**, Business Consultant, responds to Staff's proposed adjustment regarding NW Natural's five additional FTEs focused on decarbonization. They also respond to Staff's and CUB's testimony regarding the Company's renewable natural gas automatic adjustment clause. NW Natural/3600, Kravitz-Griffiths.

John J. Spanos, President of Gannett Fleming Valuation and Rate Consultants, LLC, replies to depreciation and accounting adjustments set forth by AWEC and Staff. NW Natural/3700, Spanos.

Kyle T. Walker, Senior Manager of Rates and Regulatory Affairs, responds to a number of adjustments proposed by Staff and intervenors, including forward test year capital, test year revenues and expenses, cash working capital, materials and supplies, excess deferred income taxes, Commission fees, cloud-based software capitalization, available funds used during construction, income tax flow through, decoupling, UM 2309 amortization, and removal work in progress. He also updates revenue requirement to reflect the filed cost of long-term debt stipulation with the Stipulating Parties, errors identified through Parties' opening

testimony and discovery, the updated CBA, and the removal of one FTE. NW Natural/3800, Walker.

Robert J. Wyman, Rates and Regulatory Economist, responds to Staff and intervenors regarding weather normalized use-per-customer load forecast ("UPC Forecast"), Long-Run Incremental Cost ("LRIC") study, and rate spread and rate design proposed by the Company. NW Natural/3900, Wyman.

Gregg H. Therrien, Vice President at Concentric Energy Advisors, responds to Staff and intervenors testimony concerning NW Natural's proposed LEA. Specifically, he explains why the proposed LEA is fair, is designed to support the state's decarbonization efforts (despite the invalidation of the CPP) and is a balanced and economical approach to adding new gas customers that desire service from NW Natural. NW Natural/4000, Therrien.

Jeffrey M. Zaubi, Financial Consultant, responds to the Coalition's proposed disallowance of costs associated with system investments to hook up new residential customers. He describes the Company's process for estimating the construction costs for new residential and commercial customers and demonstrates the Company's construction costs for adding new residential and commercial customers were prudently incurred and should be recovered in rates. NW Natural/4100, Zaubi.

Scott S. Johnson, Director of Gas Supply, explains why Staff's proposal to establish a sharing mechanism for gas supply hedges that exceed three years in duration is counterproductive and should not be adopted. NW Natural/4200, Johnson.

John D. Frankel, Director of Marketing, respond to adjustments related to promotional and marketing activities proposed by Staff and the Coalition. NW Natural/4300, Frankel.

As we stated in Direct Testimony, we are requesting to revise rates to reflect the critical investments we are making in our system and increasing costs. We recognize that rate increases can be difficult for our customers, but they will ultimately benefit our customers by supporting NW Natural's ability to operate a financially sound natural gas utility that will continue to provide safe and reliable gas service.

Q. Does this conclude your Reply Testimony?

A. Yes, it does.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibits of Zachary D. Kravitz

POLICY
EXHIBITS 2201 – 2202

June 4, 2024

EXHIBITS 2201-2202 – POLICY

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BEFORE THE

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POLICY
EXHIBIT 2201

June 4, 2024

NW Natural®

Winter 2024 Report

Pacific Northwest and the U.S. **Rely on the Gas System**

Frigid temperatures that hit the Pacific Northwest during the week of January 13-19 resulted in record-breaking natural gas deliveries on our system. This came at a time when the electric system was experiencing widespread power outages due to the severe weather. Through careful planning, hard work and dedication, our field crews and operations teams kept the gas flowing safely for about 2 million people in the region, many of whom were without power but could still rely on direct use of natural gas in appliances like gas fireplaces, water heaters, stoves, and generators.

System Planning Delivers Results

NW Natural's customers relied on our system like never before, with 9 million therms of gas deliveries to homes and businesses on Jan. 13, 2024, virtually matching our previous record set in Dec. 2022, and about double our average daily winter send out.

9M therms

Indispensable Energy Storage

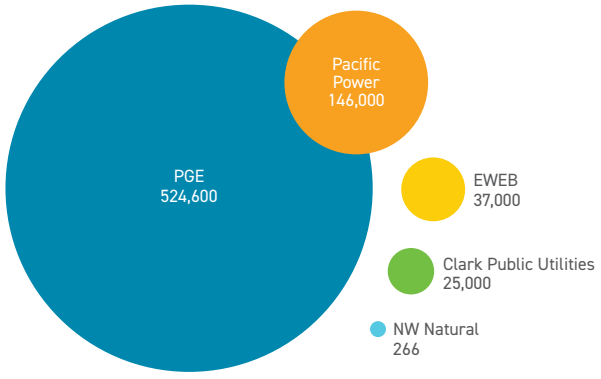
NW Natural's unique, on system storage facility in Mist, Oregon provided a new record volume of over 4.5 million therms of gas on Jan. 13, 2024 — **the equivalent of serving 630,000 residential customers in a day.** This year, we will distribute $29 million in bill credits to customers due to our Mist storage assets and pipeline capacity management.

630,000

Storm Shows Critical Need for Energy System Diversification

Hundreds of thousands in the Northwest were without power at some point during the severe weather event of Jan. 2024. While all energy systems faced challenges to mitigate, thanks to our underground energy delivery system, NW Natural was able to retain service to all but about 266 customers.

Overall Outages



Sources: https://portlandgeneral.com/news/2024-01-22-pge-restoration-complete-from-severe-winter-weather#:~:text=Customer%20outages%20over%20the%20nine, access%20and%20extended%20restoration%20times

https://www.pacificpower.net/about/newsroom/news-releases/power-restored-for-most-oregonians.html

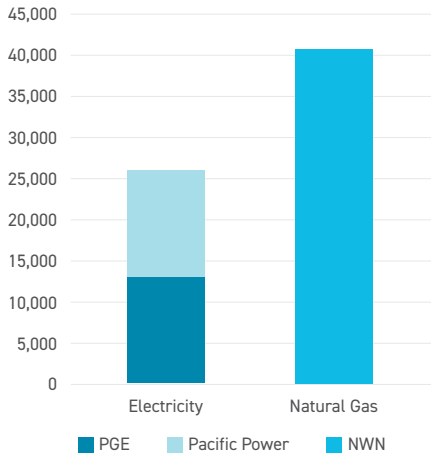
https://www.eweb.org/your-public-utility/news/nine-days-without-power-my-ice-storm-story-as-an-eweb-customer-and-employee

https://www.columbian.com/news/2024/mar/20/january-storm-cost-clark-public-utilities-about-26-million/

Heating Reliably

During the highest energy use hour on Jan. 13, 2024, NW Natural delivered **55% more energy** than local electric providers, Portland General Electric and Pacific Power, *combined.*

Delivered Energy On the Peak Hour January 13, 2024 (MMBtu/Hr)



Source: ICF using U.S. Energy Information Administration real time operating grid data

55% more energy than local providers

NW Electric System During Weather Event

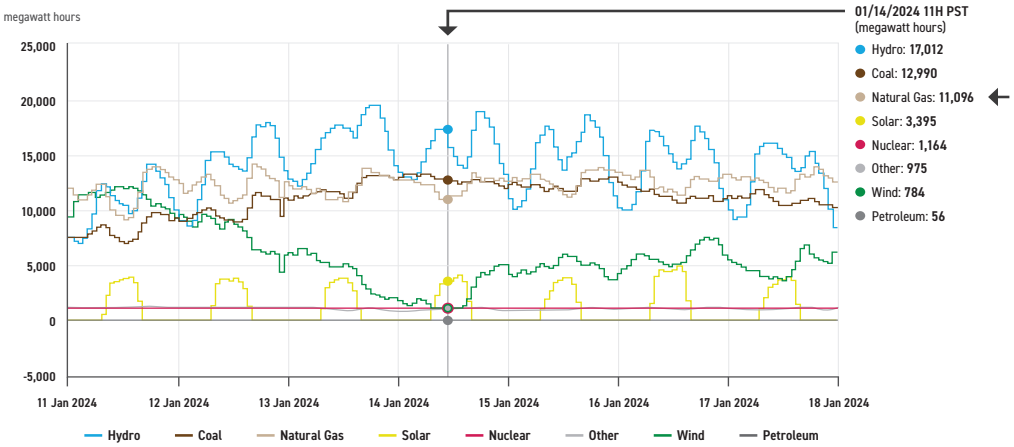
While NW Natural does not sell natural gas to electric utilities, they heavily rely on it to produce power — along with hydro and coal.

Nationally, natural gas, coal and nuclear provided 81.6% of all electric generation on Jan.15, 2024.

Source: U.S. Energy Information Administration Hourly Electric Grid Monitor, https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/regional/REG-NW

https://www.aga.org/research-policy/resource-library/natural-gas-market-indicators-special-edition/

Northwest (NW) region electricity generation by energy source 1/11/2024 – 1/17/2024, Pacific Time



Customer Perspectives

The January 2024 severe weather event reminded many of the customers and communities we serve about the critical role of natural gas for a reliable, resilient energy system.

"...has a gas stove and was able to heat up food... Other strategies that people reported using in Facebook posts included firing up gas fireplaces..."

-The Oregonian

"...Luckily for them they've got a generator and a gas stove to heat food..."

- KGW

"A gas fireplace and lots of batteries."

- A reader in response to a Pamplin Media poll about how they were handling the storm

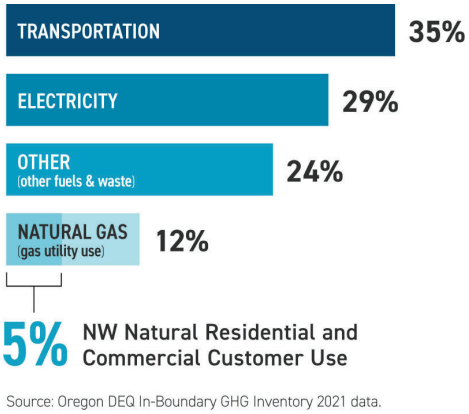
"Our gas fireplace has kept us warm today. No power since 11:10 am. Able to eat warm food cooked on the stove and stay warm during the storm. Thanks @nwnatural!"

– A NW Natural customer on social media

Electrification is Not Decarbonization

Emissions from our residential and commercial customers account for about 5% of Oregon's total greenhouse gas emissions. Transportation and electricity use remains the largest source of emissions in Oregon.

Oregon Greenhouse Gas Emissions by Sector



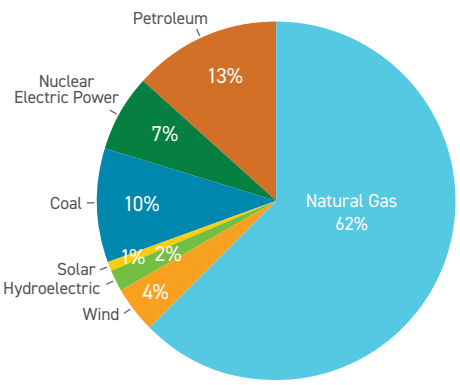
Source: Oregon DEQ In-Boundary GHG Inventory 2021 data.

Record Natural Gas Use by Electric System

Natural gas provided 62% of all the energy delivered across the U.S. during the week of Jan. 13-19.

Source: https://www.aga.org/research-policy/resource-library/natural-gas-market-indicators-special-edition/

Share of Total Energy Delivered by Source Week Ending Jan. 19, 2024



Policies designed to "electrify" natural gas space heating fail to answer three key questions:

1. Why would we limit or ban natural gas use in homes and businesses only to use even more of it in electric power plants during cold weather?
2. What is the cost to ratepayers of this policy?
3. And how will it affect energy reliability?

BEFORE THE

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NW Natural

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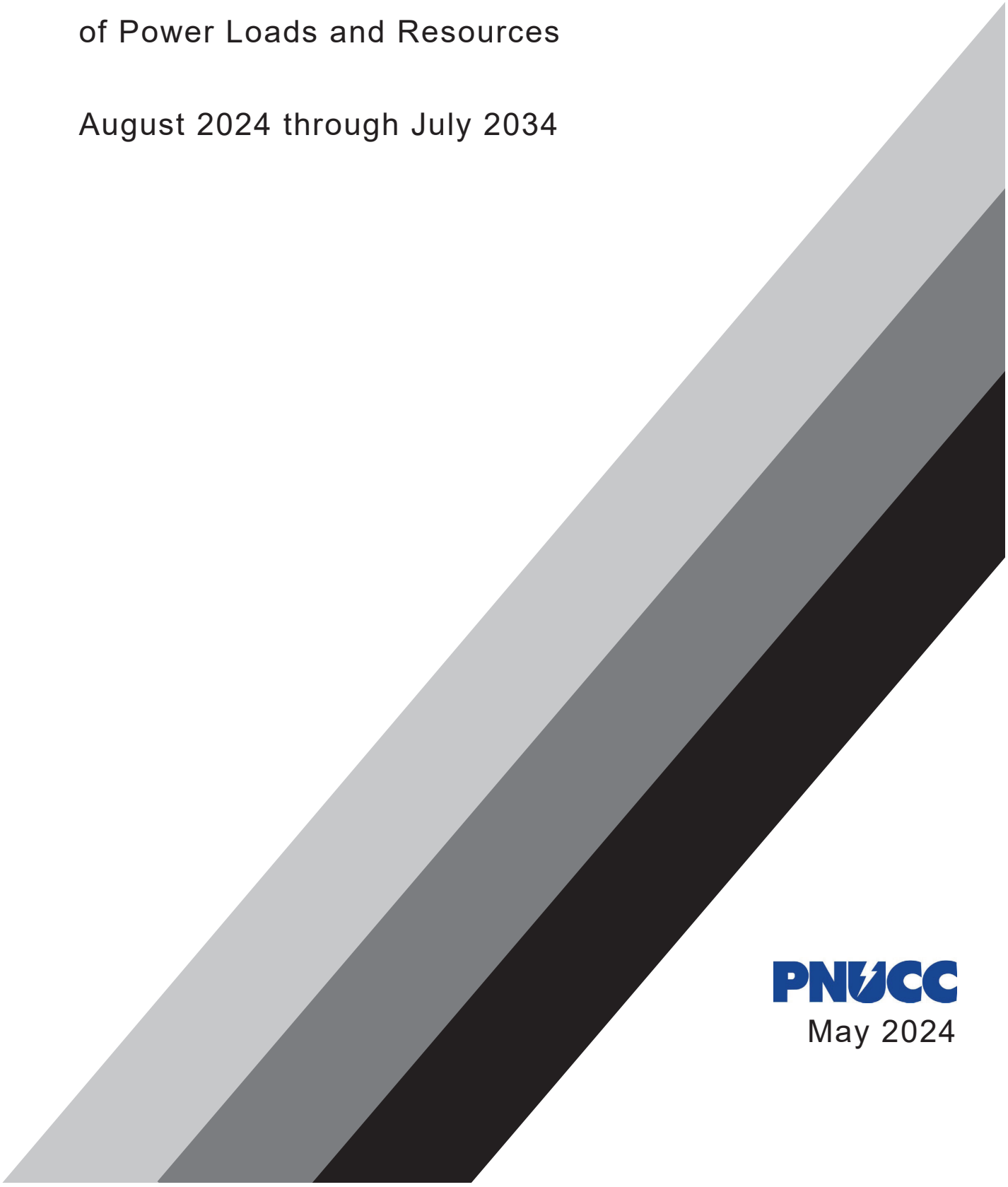
POLICY
EXHIBIT 2202

June 4, 2024

Northwest Regional Forecast

of Power Loads and Resources

August 2024 through July 2034



PNUCC

May 2024

Special thanks to PNUCC System Planning Committee members and utility staff who provided us with this information.

Electronic copies of this report are available on the

PNUCC website

www.PNUCC.org

Pacific Northwest Utilities Conference Committee

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2024 Northwest Regional Forecast

Executive Summary

From technological advancements to evolving consumer demands, electric utilities and industry partners are adapting to major shifts that are underway in the energy sector. Through collaboration, the Pacific Northwest Utilities Conference Committee (PNUCC) annually provides an assessment of the electric utility industry from a regional perspective. The effort is captured in the *Northwest Regional Forecast* (*Forecast*), a longstanding resource tracking power system trends, including shifts in demand, resource changes and emerging technologies. It is important to note that a gap between loads and resources in the *Forecast* does not necessarily mean the region will be unable to meet demand. Rather, the *Forecast* serves as a barometer for building increased awareness for how the picture is changing.

The *Forecast* anticipates a surge in demand for electricity in the Pacific Northwest over the next decade that surpasses PNUCC's previous projections. The increase is attributed to factors such as data center expansion, high-tech manufacturing growth and the trend toward electrification. Electric utilities across the nation are projecting increases in demand for similar reasons.

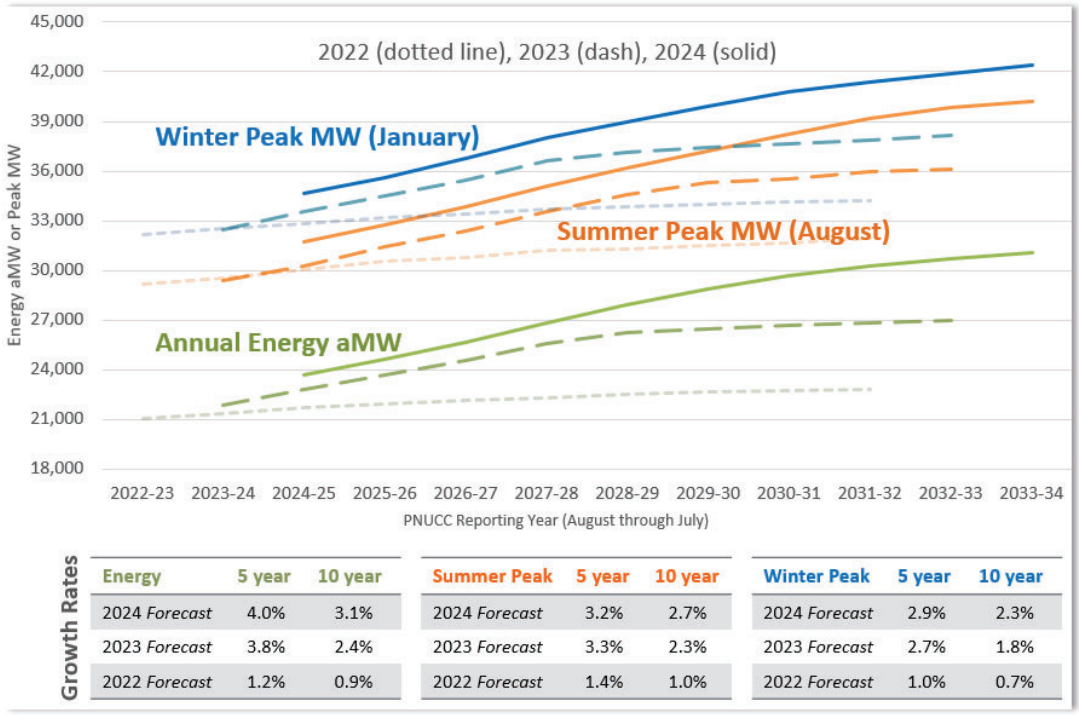
The dual challenge of extraordinary growth in demand and the transition to lower carbon-emitting generation resources translates to a tremendous and urgent need to upgrade the region's electricity infrastructure – including expanding transmission capacity and diversifying power supplies as well as accelerating the adoption of advanced grid technologies.

Surge in Projected Demand Signals End of Stagnant Growth

Demand for electricity is projected to increase from about 23,700 average megawatts (aMW) in 2024 to about 31,100 aMW in 2033 (an increase of 7,400 aMW), which is an increase in demand of over 30% in the next 10 years (as shown Figure 1). For comparison, last year's *Forecast* projected demand could rise by 24% in 10 years.

The rapid expansion of data centers is one of the reasons for the expected increased volume in the Northwest. According to a Cushman & Wakefield report that evaluates data centers by their electricity usage, the Oregon data center market ranks as the fifth largest in the nation. High-tech manufacturing and the trend toward electrification also contribute to the expected increase in demand.

Figure 1: 2024 Load Forecast Compared to 2023 and 2022



Growth Rates

Energy	5 year	10 year
2024 *Forecast*	4.0%	3.1%
2023 *Forecast*	3.8%	2.4%
2022 *Forecast*	1.2%	0.9%

Summer Peak	5 year	10 year
2024 *Forecast*	3.2%	2.7%
2023 *Forecast*	3.3%	2.3%
2022 *Forecast*	1.4%	1.0%

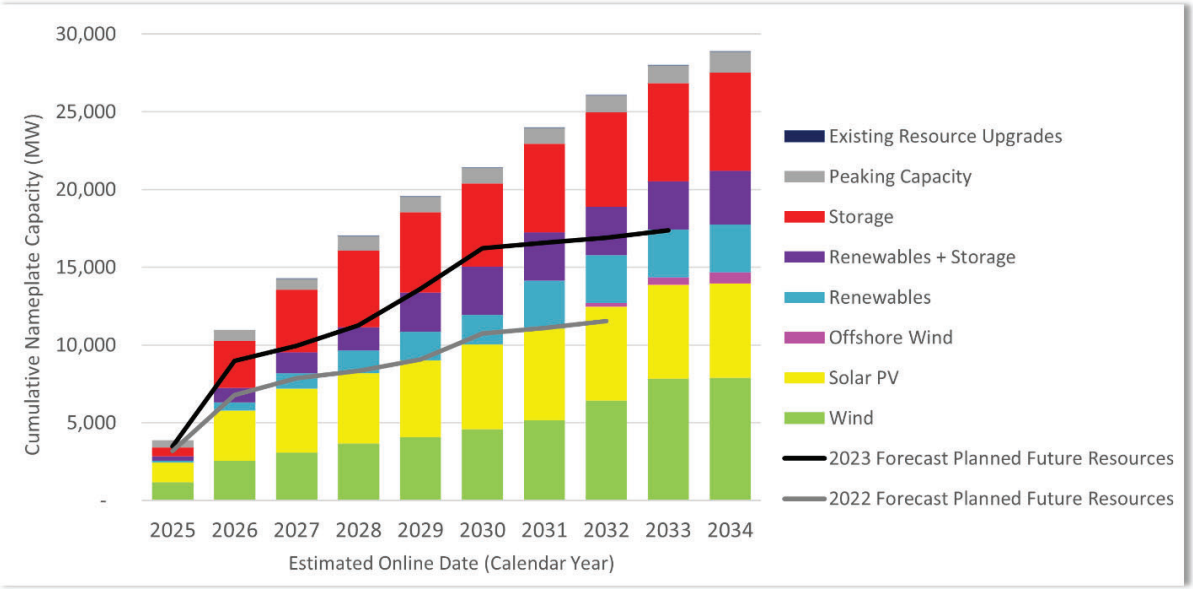
Winter Peak	5 year	10 year
2024 *Forecast*	2.9%	2.3%
2023 *Forecast*	2.7%	1.8%
2022 *Forecast*	1.0%	0.7%

Another way to measure demand is by the annual energy load growth rate. The 10-year annual energy load growth rate for the *2024 Forecast* is 3.1% (annually compounded). Utilities in aggregate have not forecast a rate of growth for annual energy load this high since the early 1980s (which is shown in Figure 9). Three years ago, the regional annual load growth rate was forecast to be 0.9%, which was more in line with the decades long trend of about 1-2% per year. Utilities are experiencing load growth due to different factors and at varying rates. For example, some utilities are experiencing increased demand from a boom in residential growth due to population shifts, while other utilities have flat or decreasing demand forecasts because of energy efficiency investments or more stringent state and local building codes and standards.

Utility Plans Include More Resources

Over the next decade, utilities have identified plans for about 29,000 megawatts (MW) nameplate capacity of new resources to meet customer energy and capacity needs. Figure 2 shows an unprecedented development of resources on a short timeline for the industry. Past *Forecasts* showed more than 17,000 MW nameplate (solid black line) were planned by 2033 and more than 11,000 MW nameplate (solid gray line) by 2032. PNUCC aggregates utility-reported planned future resources from resource planning assessments to provide a regional picture. Utility plans are reviewed and updated frequently and are developed through comprehensive analysis with input from a stakeholder process. Consequently, these plans, particularly the longer-range elements, change over time.

Figure 2: Planned Future Resources



In Figure 2 the stacked bars amount to the cumulative nameplate for planned future resources by resource type for each year of the *Forecast*. Wind, solar and battery resources make up most of the planned generation as utilities look to decarbonize their resource portfolios. For utilities that have not been specific about the kind of renewable resources included in their plans, the resources are identified as renewables.

The data in the graph does not include committed resources for 2024 and 2025 and coal to natural gas conversions. Committed resources and coal to gas conversions get combined with existing resources in the load and resource balance picture. Further, this graph does not reflect any uncommitted independent power producer resources with which utilities or customers may acquire or enter into contracts.

Storage is a big part of the solution

Hydroelectric dams are the cornerstone of the Pacific Northwest electricity system, providing over 33,000 MW of installed capacity. They generate clean power and store water in large reservoirs behind the dams that can be used to dependably meet seasonal and peak demands. Because hydroelectric dams are flexible resources that can store fuel, they have helped integrate new variable renewable resources in the region. With the growth of wind and solar power, utilities are also starting to add battery storage resources to store surplus energy and supply it to the grid during periods of high demand, or periods when wind and solar generation decreases.

Batteries co-located with renewable generation, standalone batteries and pumped hydro increase through the *Forecast*. The most commercially available battery storage technology — utility scale lithium-ion — is designed to discharge their capacity over a four-hour period before needing to recharge. In the Northwest, which is prone to prolonged peak demand and fuel limitations over multiple cold days, long duration energy storage could be a complimentary solution. Developers are making progress on longer

duration battery and compressed air energy storage technologies, but they are not yet showing up in utility planned future resources.

Energy efficiency and demand response

Energy efficiency and demand response programs have reduced the need for new resource development in the past and continue to be a critical component of an adequate power supply by helping lower energy use and peak demand.

Figure 3: Ten-year Cumulative Energy Efficiency Projections

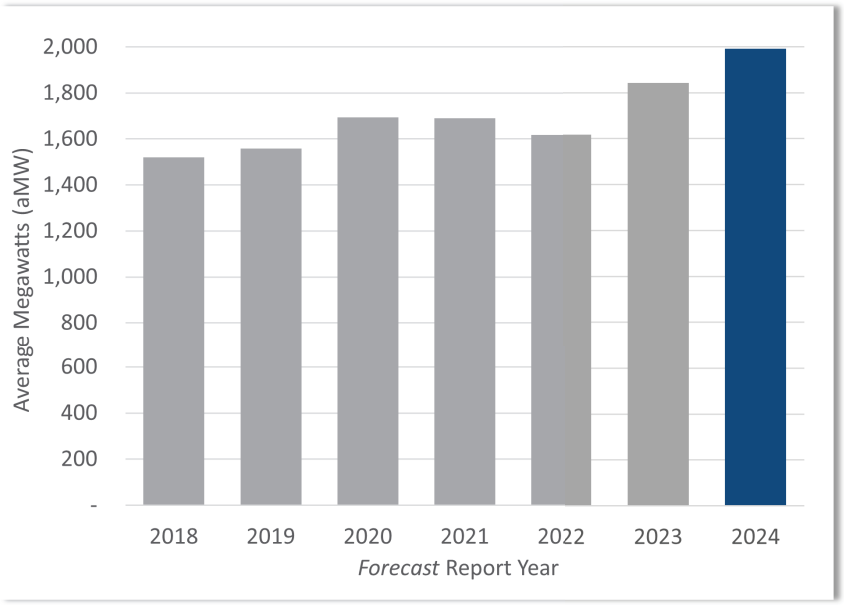
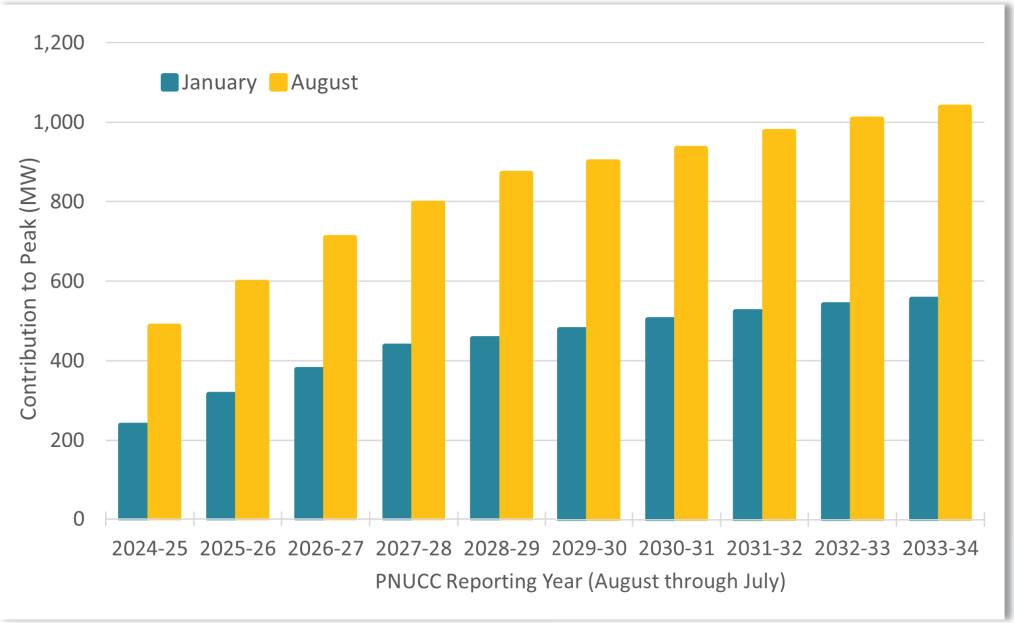


Figure 3 shows projected cumulative energy efficiency savings of around 2,000 aMW over the next 10 years – approximately 150 aMW higher this year than last year. This builds on the nearly 7,700 aMW of energy efficiency that has been acquired in the region over the past 45 years.

Energy efficiency is an important resource to meet demand now and in the future, as well as a strategy to mitigate risk from uncertainty. The Northwest Power and Conservation Council's (Council) *2021 Power Plan* recognized that some jurisdictions would need to invest in energy efficiency beyond the Council's target as part of a cost-effective strategy for reducing carbon emissions.

Figure 4: Demand Response Contribution to Peak



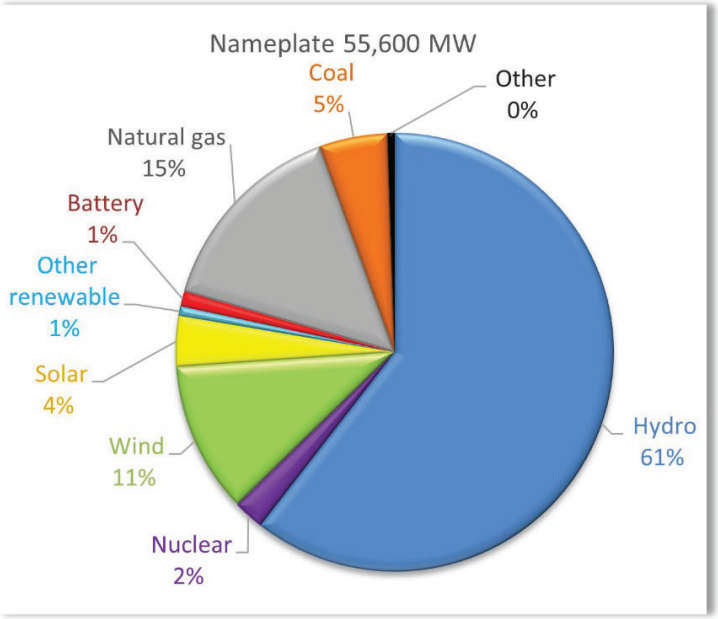
Demand response programs are an effective tool during summer and winter extreme weather events to shift consumption of electricity away from peak periods. As the grid becomes more strained, utilities are incorporating more customer demand response.

Figure 4 shows the utilities' active and projected summer and winter demand response programs. The *Forecast* projects summer demand response to double, reducing the region's one hour peak by about 500 MW in 2024 to over 1,000 MW in 2033. While summer demand response programs continue to provide almost twice the peak load reduction in comparison to winter demand response programs, the *Forecast* projects a winter demand response increase from over 200 MW in 2024 to close to 600 MW in 2033. Further, several utilities have expressed their intent to explore pilot projects and deploy new demand response programs within their service territories that are not yet showing up in the *Forecast*.

Northwest Generating Resources

The pie chart in Figure 5 shows the Northwest Utility Generating Resources for 2025. Total installed capacity for 2025 is about 55,600 MW. This year the *Forecast* includes a new category for battery storage, which has grown to 1% and is expected to quickly become an even larger share. Utilities also rely on imports from outside the region, energy efficiency and demand response to meet load.

Figure 5: Northwest Utilities Generating Resources



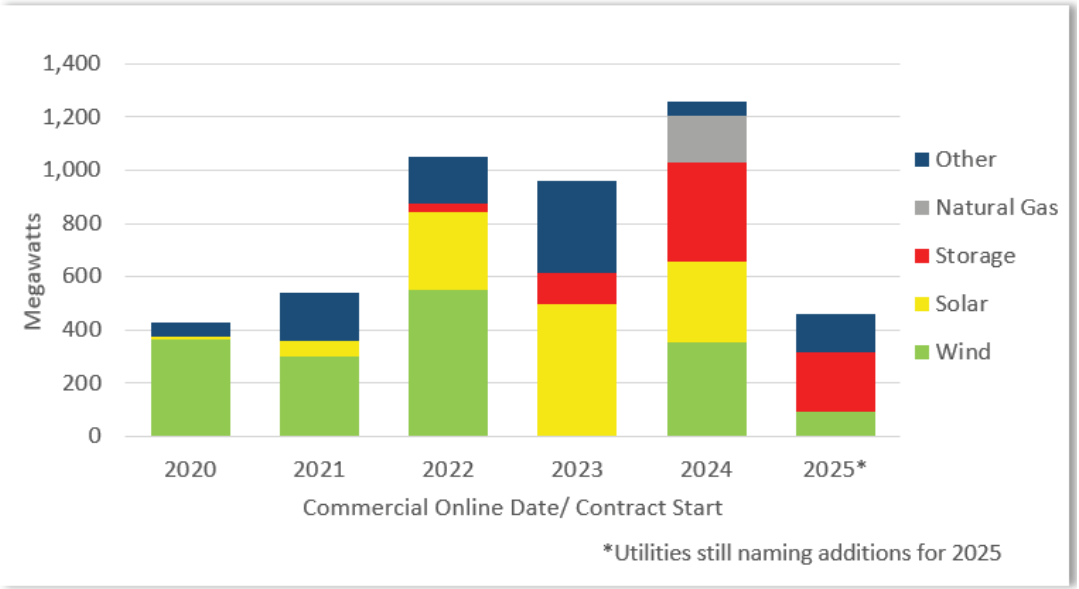
The Bar for New Resources Keeps Moving Higher

Northwest utilities have been steadily adding new resources to the regional generating mix to replace carbon-emitting resources. While the total installed capacity has increased slightly, these new resources have not significantly expanded to meet the anticipated rise in electricity demand.

Reported long-term acquisitions

Over the past five years, the majority of new generating resources have been solar and wind, with some additions of battery storage. The incremental additions reported from 2020 through 2025 are shown in Figure 6. Past *Forecasts* have not summarized this information, but the landscape is changing, and it is important to show how the picture is evolving. The data include committed resources that are named and under construction with a high degree of certainty to be added.

Figure 6: Incremental Nameplate Capacity 2020-2025 Acquisitions

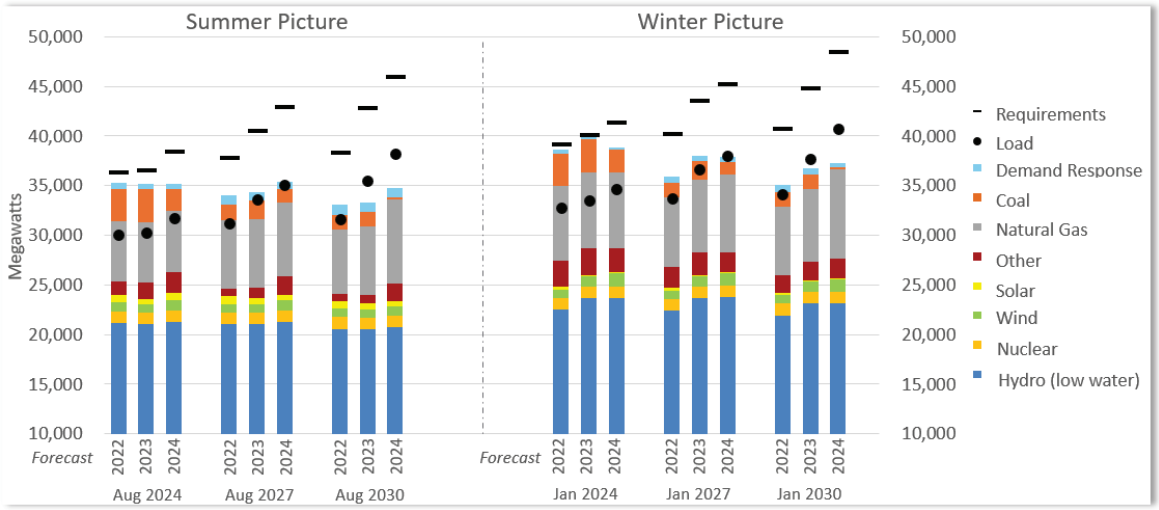


In total, utility reported resource acquisitions have increased the regional utility resource stack by approximately 4,700 MW (nameplate capacity) from 2020 through 2025. Wind additions are 1,657 MW, solar additions are 1,166 MW, storage additions are 748 MW and natural gas additions are 175 MW. The other category in Figure 6 includes imports of 335 MW, new contracts for existing regional resources of 598 MW and 12 MW of hydro upgrades. Because utilities are still naming additions for 2025, the 2025 planned future resources data in this graph appears relatively low at approximately 450 MW.

Figure 7 illustrates how the bar for future resources keeps moving higher. This graph compares the *2022 Forecast*, *2023 Forecast* and *2024 Forecast* of loads and resources for three future years in summer and winter. The colored stack bars are the utility's view of how existing and committed resources contribute to peak requirements. The stack does not include planned future resources. The black dot shows expected peak load, not extreme weather conditions. The black dash above the stack is the requirements – the sum of peak load, a 16% planning margin and export obligations. The resource contributions to peak requirements are shown based on expected operations and low water conditions. Firm imports are included in the other category, along with batteries and miscellaneous other resources that do not fit the main categories.

Tables 3 and 4 in the report provide the complete picture of 10 years of growing deficits. By the end of the forecast the projected summer and winter peak deficits are more than 13,700 MW in both seasons and utilities are forecasting that it will take about 29,000 MW of installed nameplate capacity (Table 9) to fill these gaps.

Figure 7: 2024 Load and Resource Forecast Compared to 2023 and 2022



This load and resource balance is not a resource adequacy assessment for the region. Rather, it is tracking the trend of the forecat load and resource balance to help understand how the picture is changing and to build awareness. To fill the gap, the region will need an unprecedented amount of new generation in the next 10 years that will significantly change the Pacific Northwest resource mix. Utilities are evaluating how existing and new generating resources can be counted on. The Western Resource Adequacy Program (WRAP) is helping utilities understand how much power the region will need to have an adequate system.

Projected demand driven by data center expansion

Compared to this time last year, there is a noticeable nationwide increase in awareness about the rapid expansion of data centers that are essential for advancing Artificial Intelligence (AI) and its incredible appetite for electricity. The use of AI is becoming increasingly important to the nation's economy. During a keynote address at a recent energy industry conference, Microsoft co-founder Bill Gates emphasized electricity is the critical factor determining the profitability of data centers and he expressed astonishment over the staggering amount of power AI will consume. It is challenging to forecast the extent of the potential increase and when it might show up in the region. Some companies developing new data centers are making plans that are not included in the *Forecast*.

Meeting this demand will be quite an undertaking, especially considering the evolving electricity supply. Many companies developing data centers are committed to minimizing their carbon footprints and prefer to power their facilities with carbon-free resources. Clean hydropower, affordable electricity and business incentives have attracted investment in this region, but finding enough power in the future will be a significant challenge. These companies are willing to pay to procure carbon-free, reliable power products to meet their corporate goals and are also exploring solutions that could help reduce power consumption.

Finding even more generating resources for meeting the demand from increased electrification will only increase the bar.

Electrification still to come

Utilities are trying to better understand how much energy and capacity could be needed for the electrification of buildings, transportation, and commercial and industrial applications. The overall effect of electrification is expected to increase over the next several years. Utilities are examining the implications of increased electrification in their load forecasts and updating their plans, a trend that cannot yet be fully captured in PNUCC's annual forecast.

Electric vehicle (EV) adoption among consumers has been increasing. Based on information PNUCC received from utilities, increased demand from charging EVs is projected to approach 4% of total load at the end of the 10-year period. Some utilities are expecting a higher percentage. Seattle City Light for example forecasts EV load could be 10% of their total load at the end of the 10-year period.

Electrification of buildings and industry is expected to lead to a significant increase in electricity consumption, but it will not impact utilities uniformly. Washington, for example, is incorporating building electrification mandates into statewide energy codes. Recent updates to Washington energy codes require builders to install electric heat pumps for space and water heating in most new commercial buildings and multi-family residences. Energy efficiency efforts may offset some of these increases and new load management technologies entering the market that are more controllable could help reduce peak demand when grid capacity is constrained.

Capacity concerns and transmission challenges create risk

Utilities need capacity, not just energy. The capacity contribution of wind and solar resources are dependent on several factors and actual generation can be less than installed nameplate capacity. The ability for a resource to provide power during a peak load event depends on the time of year, type of generating resource, its geographic location, access to fuel, access to transmission, and other factors that impact the capability to generate and deliver power at any given time. To maintain sufficient system resource adequacy, Pacific Northwest utilities rely heavily on the dependable capacity of hydro, nuclear, coal and natural gas. Battery storage increases dependability by storing surplus energy and supplying it later in the day when the energy is needed more, however, current commercial utility scale batteries have limits for meeting demand during multi-day events, like a cold snap in the Pacific Northwest.

While recent federal incentives have supercharged the market for clean energy and storage development and improved economic certainty for projects, other uncertainties – like grid interconnection, supply chain delays and project approvals – remain challenging. Project developers say grid interconnection is the leading cause of project delays and cancellations. Submitting an interconnection request and completing grid studies is only one of many steps in the development process; developers are also running into delays in getting agreements with landowners and experiencing increased equipment costs and delivery delays.

A good representation of how big the utility resource acquisition challenge could be is that the *2024 Forecast* shows utilities could add about 1,250 MW nameplate capacity by the end of 2024. Compared to the *2023 Forecast,* that number is about 50% less than projected last year.

The ability to build enough generation and acquire enough capacity is one thing; the ability to deliver it is another. Expanding the capacity of the transmission system will be critical for reliably serving the growing load and delivering more power from where it is produced to where it is needed. PNUCC members strongly believe the region should work across the Western Interconnection to develop a coordinated approach to grid planning that will identify transmission upgrades and expansion to address transmission constraints and reliably and affordably meet the needs of the future electric grid. Utilities, industry partners, states and others are actively engaged in building a coalition across the Western region to improve coordination in transmission planning through the Western Transmission Expansion Coalition (WestTEC). This initiative aims to identify and build support for transmission solutions that reduce reliability risks and facilitate the interconnection of new electricity generation to meet future load requirements.

Based on experience, utilities say planning is essential, but permitting new transmission lines is the biggest hurdle to expanding the electric transmission system, especially in the West. Existing permitting and siting rules and regulations foster perpetual legal challenges that have created decadal delays in the construction of new transmission projects.

Prioritizing Resource Adequacy and Reliability

Utilities are concerned about ensuring sufficient and reliable supply to meet demand, particularly during extreme weather events that are increasing in frequency due to climate change. The region needs a power and transmission system that is bigger than the weather because the region's customers demand a system that is both adequate and reliable.

The Pacific Northwest region will continue to rely on imports and West-wide collaboration is crucial for accessing diverse resources. Utilities are making commitments to broader regional wholesale electricity markets that would help make more efficient use of the existing and newly added resources and optimize transmission across a broader footprint. Organized electricity markets centrally optimize the least-cost dispatch of resources for utilities on the day-ahead through real-time operating timeframe to meet load. This allows for a centrally optimized system of matching buyers and sellers of wholesale electricity. Many Pacific Northwest utilities voluntarily participate in the Western Energy Imbalance Market (WEIM), which has become a valuable tool on a real-time interval that has delivered significant financial benefits to regional participants and improved grid reliability. Utilities are advancing efforts to develop and participate in day-ahead markets.

Extreme weather tests the system

The multi-day cold snap in January 2024 is an example of coming dangerously close to having an inadequate supply. The severe weather from January 12-16, 2024 pummeled the Pacific Northwest. Freezing temperatures were lower on the westside than they were on the eastside at the beginning of the event, which meant balancing authorities experienced system peaks at different times. Demand could have been significantly greater if temperatures across the region had dropped at the same time. The Pacific Northwest relied heavily on imports from the Desert Southwest and Rocky Mountain regions to maintain reliability due to high demand and low water conditions. Natural gas system constraints also reduced fuel supplies to gas-fired power plants, which impacted capacity and forced some utilities to rely more on imports.

The Western Power Pool, the program administrator for WRAP, provided an assessment of the January 2024 cold weather event. WPP found peak load consistently exceeded historical peaks or at or near historical peak load in many areas. “The amount of inter-regional support necessary to manage Balancing Authority (BA) operations through the cold weather event is indicative of the pressing need to address resource adequacy and potential capacity shortfalls as soon as practicable, highlighting the value of a resource adequacy program with a broad geographic footprint and diversity of load and resources,” WPP wrote. WPP is calling on utilities to use the January experience to enhance preparedness and help improve the resource adequacy program.

The region’s pursuit of solutions for ensuring resource adequacy includes extending the usefulness of existing infrastructure, like converting coal plants to natural gas plants, ensuring a stable natural gas supply to run natural gas plants and exploring emerging technologies.

As coal declines, natural gas is expected to increase and provide reliable supply

The regional coal and natural gas picture is shifting. Utilities continue to exit their positions in coal plants as required by state laws. On the other hand, some utilities have found it is cost-effective to repurpose existing infrastructure to reduce emissions and are planning to convert from coal to natural gas-fired generation. Natural gas can provide a bridge to meet peak demand and fill in during potential low water years until sufficient capacity and transmission infrastructure can be added.

Figure 8: NW Utility Coal and Natural Gas Plant Availability

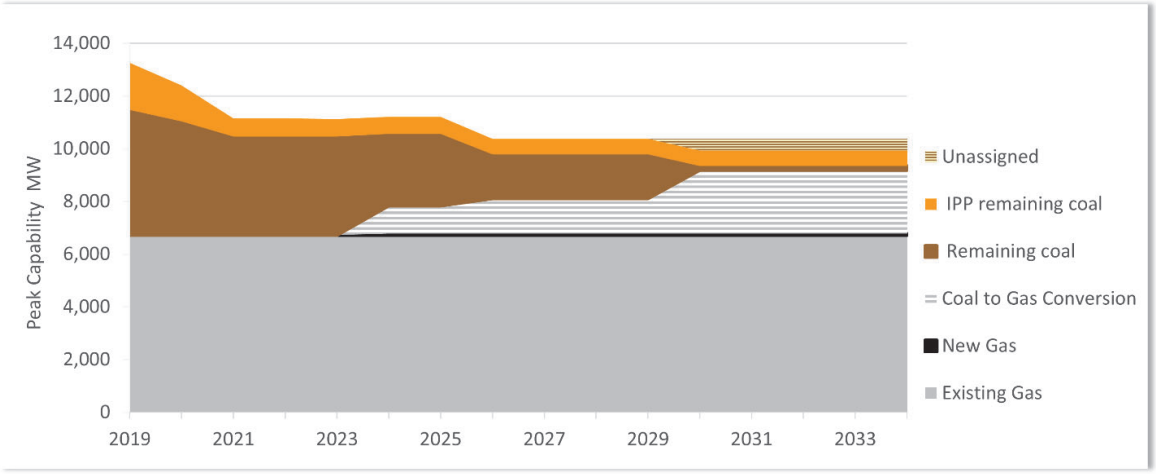


Figure 8 shows expected changes for coal and natural gas resources in the region. It begins with the picture in 2019. Looking ahead, regional coal availability declines gradually. State law requires that coal-fueled resources are eliminated from Oregon's electricity resources by January 1, 2030. Washington's Clean Energy Transformation Act (CETA) requires utilities to eliminate coal-fired resources from Washington rates by December 31, 2025. This decline shows up as retirements and coal-to-natural gas conversions. There is a remaining amount of coal that will be owned by Independent Power Producers and is not assigned to any load. A small amount of regional coal remains unassigned with no future owner identified.

Existing gas plant capability shown in the darker gray shaded area has remained steady. There is a small uptick in natural gas due to the anticipated addition of a new gas plant in 2024. Planned conversions from coal to natural gas are shown in the lighter gray area. (Figure 8 shows Jim Bridger Units 3-4 as coal to gas conversions in 2030. The picture does not reflect PacifiCorp's recently announced plans to retrofit these units with carbon capture technology by 2028 and continue operating them through 2039.)

Gas-electric coordination

Electric and natural gas system infrastructure is vital to the reliable operation of the power system. Electric energy and natural gas systems provide reliable energy to millions of people in the Pacific Northwest. The region depends on natural gas supply, storage and pipelines to fuel electric generating plants and heat homes. The interdependence of the two energy sources continues to grow as the region experiences extreme weather events more frequently and relies more on natural gas resources to meet peak demand. Building understanding and awareness of these systems and improving coordination between the electric and natural gas sectors is critical to ensure the necessary investments are made to keep the systems reliable as both sectors decarbonize.

Emerging technologies on the horizon

Regional utilities are actively exploring emerging technologies to meet future demands. Of particular interest to utilities are long duration energy storage, clean hydrogen, advanced nuclear and offshore wind. Puget Sound Energy (PSE) has announced it is partnering with Form Energy to evaluate multi-day energy storage solutions. The partnership allows both companies to collaborate on the development of a 10 MW, 100-hour iron-air battery pilot in PSE's service area. Long duration energy storage can provide power over several days as compared to most commercially available batteries that supply about four hours of energy storage. The pilot project will help PSE determine if a future utility-scale project could be deployed as early as the end of 2026.

Investor-owned and public power utilities are actively involved in the Pacific Northwest Hydrogen Hub (PNWH2), one of seven Regional Clean Hydrogen Hubs across the nation selected to receive federal funding to kick start clean hydrogen production. The PNWH2 Hub spans Washington, Oregon and Montana, and anticipates leveraging renewable resources to produce clean hydrogen exclusively via electrolysis. The economics and reach of this nascent technology will be impacted by the outcome of federal tax credit rulemaking.

There is a resurgence of interest and growing support for advanced nuclear reactors because of the role the non-emitting resource can play in supporting the transition to clean energy in a reliable way. Energy Northwest and X-Energy are jointly developing a next-generation nuclear plant in Washington. Energy Northwest has partnered with public power and investor-owned utilities to study the feasibility of building small modular nuclear reactors near the Columbia Generating Station, the state's only commercial nuclear energy facility. This year, Washington state legislators and Governor Jay Inslee supported allocating $25 million from state funds to study the pros and cons. Energy Northwest anticipates the first reactor could come online by 2031. Furthermore, PacifiCorp's 2023 IRP Update continues to show the value associated with TerraPower's nuclear demonstration project in Kemmerer, Wyoming. The nuclear power company, which is backed by Bill Gates, plans to break ground on the project this year.

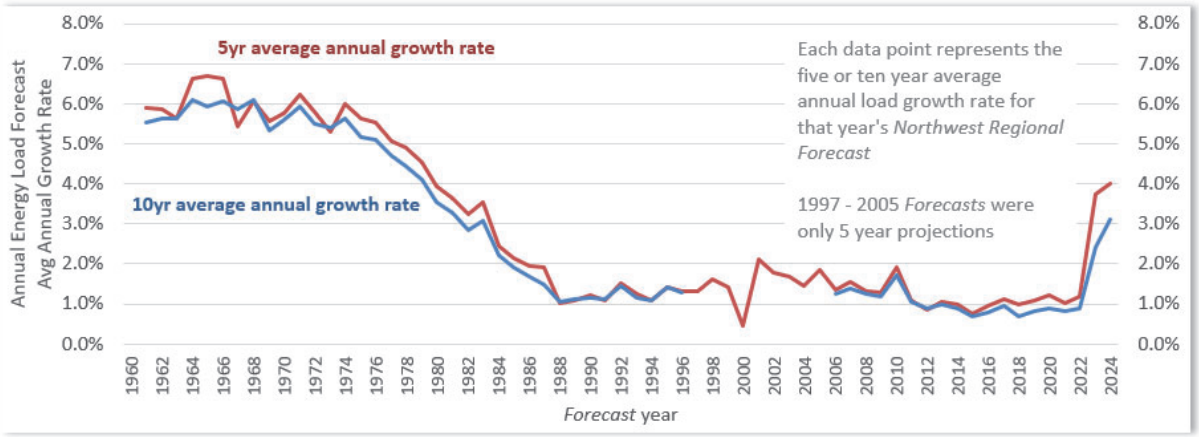
Except for offshore wind, emerging technologies such as long duration energy storage, clean hydrogen, advanced nuclear and others do not show up in the *Forecast*, but they could profoundly reshape the future regional energy landscape.

Utilities are also deploying and finding new ways to partner with customers to reduce energy use at peak times. Some utilities are exploring Virtual Power Plants (VPPs) as a way of managing customer-side resources. In general, a VPP is a portfolio of actively controlled distributed energy resources (DER). Operation of DERs is optimized to provide benefits to the power system and consumers. To a degree, VPPs have existed for decades as demand response programs. But VPPs are rapidly evolving to leverage the expanding mix of DER technologies. A VPP that reliably leverages residential load flexibility could contribute to resource adequacy.

Conclusion

Utilities in aggregate have not forecast a rate of growth for annual energy load this high since the early 1980s. This represents quite a change from the past 40 years of relatively modest growth rates of about 1-2%.

Figure 9: Historical Load Forecast Growth Rates



To accommodate the forecasted surge in demand, the region is planning to add an unprecedented 29,000 MW of new resources in 10 years while decarbonizing the electricity supply. This is an extraordinary number of new resources to develop in 10 years. A more connected grid would provide access to a wider range of resources and allow for the sharing of energy over larger distances. This would help balance the fluctuations in demand and supply, while also enhancing the resilience of the grid. Collectively, Pacific Northwest utilities are building deeper awareness of the crucial need to optimize the system, expand transmission capacity and rapidly integrate additional generating resources. By working together, the region can unlock the solutions that will keep the grid reliable and affordable.

Overview

Each year the *Northwest Regional Forecast* compiles utilities' 10-year projections of electric loads and resources which provide information about the region's need to acquire new power supply. The *Forecast* is a comprehensive look at the capability of existing and new electric generation, long-term firm contracts, expected savings from demand side management programs, and other components of electric supply and demand in the Northwest.

This report presents estimates of annual average energy, seasonal energy and winter and summer peak capability in Tables 1 through 4 of the Northwest Region Requirements and Resources section. These metrics provide a multidimensional look at the Northwest's need for power and underscore the growing complexity of the power system. The information is intended to identify regional trends and general themes based on utilities' resource planning assessment results, rather than provide a precise metric of resource adequacy.

Northwest new and existing generating resources are shown by fuel type. Existing and committed resources are listed in Tables 5, 6 and 10. Table 5, Recently Acquired Resources, highlights projects and supply that became available most recently. Table 6, Committed New Supply, lists projects where construction has started or supply is firmly committed, as well as contractual arrangements that have been made for providing power at a future time. Table 10, Northwest Utility Generating Resources, is a comprehensive list of generating resources that make up the electric power supply for the Pacific Northwest that are utility-owned or utility-contracted.

In addition, utilities have demand side management programs in place to reduce the need for generating resources. Table 7, Demand-Side Management Programs, provides a snapshot of expected savings from these programs for the next ten years. Lastly, Tables 8 and 9, Planned Future Resources, compile what utilities have reported in their individual resource planning assessments to meet future need.

Planning Area

The Northwest Regional Planning Area is the area defined by the *Pacific Northwest Electric Power Planning and Conservation Act*. It includes: the states of Oregon, Washington, and Idaho; Montana west of the Continental Divide; portions of Nevada, Utah, and Wyoming that lie within the Columbia River drainage basin; and any rural electric cooperative customer not in the geographic area described above but served by BPA on the effective date of the *Act*.

Northwest Region Requirements and Resources

Table 1. Northwest Region Requirements and Resources – Annual Energy shows the sum of the individual utilities' requirements and firm resources for each of the next 10 years. Expected firm load and exports make up the total firm regional requirements.

Average Megawatts	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34
Firm Requirements										
Load [1/]	23,708	24,643	25,684	26,850	27,945	28,859	29,657	30,240	30,714	31,093
Exports	515	515	515	514	514	511	511	511	511	512
Total	24,223	25,158	26,199	27,365	28,460	29,370	30,167	30,750	31,225	31,605
Firm Resources										
Hydro [2/]	11,437	11,439	11,418	11,402	11,208	11,142	11,142	11,142	11,142	11,119
Small Thermal/Misc.	28	28	28	28	18	11	11	11	11	11
Natural Gas [3/]	5,117	5,321	5,361	5,361	5,361	5,534	5,653	5,656	5,653	5,653
Renewables-Other	289	298	298	296	295	295	292	284	275	276
Solar	443	483	502	503	505	506	506	498	484	480
Wind	1,772	1,791	1,771	1,714	1,682	1,657	1,642	1,642	1,639	1,640
Cogeneration	32	19	15	14	14	14	14	14	14	14
Imports	467	467	467	453	380	324	310	310	222	160
Nuclear	994	1,116	994	1,116	994	1,116	994	1,116	994	1,116
Coal	2,006	1,450	1,100	1,086	1,092	417	102	102	94	100
Total	22,584	22,412	21,956	21,973	21,550	21,016	20,666	20,776	20,529	20,569
Surplus (Deficit)	**(1,640)**	**(2,746)**	**(4,243)**	**(5,392)**	**(6,910)**	**(8,354)**	**(9,502)**	**(9,975)**	**(10,695)**	**(11,036)**

[1/] Load net of energy efficiency
[2/] Firm hydro for energy is the generation expected assuming critical (8%) water condition (the methodology is changed for the 2023 report)
[3/] More energy may be available from natural gas power plants

Table 2. Northwest Region Requirements and Resources – Monthly Energy shows the monthly energy values for the 2024-2025 operating year.

Average Megawatts	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul
Firm Requirements												
Load[1/]	23,293	21,431	21,347	23,889	26,524	26,544	25,867	23,741	22,544	21,893	22,939	24,488
Exports	775	614	455	455	455	455	455	455	455	455	533	620
Total	24,068	22,045	21,802	24,344	26,979	26,999	26,322	24,196	22,999	22,348	23,472	25,108
Firm Resources												
Hydro[2/]	11,775	9,121	9,674	11,546	12,907	11,481	10,362	10,848	9,545	11,234	15,413	13,002
Small Thermal/Misc.	26	26	27	29	31	30	30	30	30	29	22	25
Natural Gas[3/]	4,861	4,848	4,961	5,135	5,250	6,194	6,170	4,835	4,775	3,810	4,804	5,807
Renewables-Other	297	292	290	284	276	275	276	294	288	290	302	303
Solar	658	538	373	207	153	151	260	392	518	595	710	755
Wind	1,650	1,496	1,677	1,849	1,762	1,707	1,772	1,888	1,978	1,796	1,939	1,748
Cogeneration	32	32	25	33	36	37	35	32	31	30	28	33
Imports	230	220	275	481	569	519	517	433	336	326	328	331
Nuclear	1,116	1,116	1,116	1,116	1,116	1,116	1,116	1,116	1,116	360	409	1,116
Coal	2,057	2,058	2,054	2,076	2,066	2,082	2,060	2,080	1,951	1,782	1,774	2,036
Total	22,703	19,746	20,472	22,755	24,166	23,593	22,598	21,947	20,567	20,251	25,730	25,155
Surplus (Deficit)	**(1,365)**	**(2,299)**	**(1,330)**	**(1,589)**	**(2,813)**	**(3,406)**	**(3,724)**	**(2,249)**	**(2,432)**	**(2,097)**	**2,259**	**48**

[1/] Load net of energy efficiency
[2/] Firm hydro for energy is the generation expected assuming critical (8%) water condition (the methodology is changed for the 2023 report)
[3/] More energy may be available from natural gas power plants

Table 3. Northwest Region Requirements and Resources – Winter Peak

The sum of the individual utilities' firm requirements and resources for the peak hour in January for each of the next 10 years are shown in this table. Firm peak requirements include a planning margin to account for planning uncertainties.

Megawatts	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Firm Requirements										
Load [1/]	34,658	35,633	36,761	38,033	38,940	39,932	40,763	41,411	41,900	42,377
Exports	1,143	1,142	1,142	1,142	1,142	1,142	1,142	1,142	1,142	1,142
Planning Margin [2/]	5,545	5,701	5,882	6,085	6,230	6,389	6,522	6,626	6,704	6,780
Total	41,346	42,476	43,784	45,259	46,312	47,462	48,427	49,178	49,746	50,299
Firm Resources										
Hydro [3/]	23,660	23,658	23,658	23,751	23,651	23,608	23,126	23,126	23,033	22,662
Demand Response	237	315	378	436	456	479	503	523	540	555
Small Thermal/Misc [4/].	801	803	801	801	783	784	785	786	788	789
Natural Gas	7,641	7,901	7,903	7,903	7,903	8,965	8,965	8,965	8,965	8,965
Renewables-Other	447	443	424	419	419	419	415	403	393	393
Solar	103	108	111	102	102	103	103	102	96	94
Wind	1,323	1,321	1,303	1,285	1,276	1,286	1,295	1,283	1,266	1,268
Cogeneration	38	18	16	16	16	16	16	16	16	16
Imports	1,164	1,293	927	696	806	873	788	493	493	493
Nuclear	1,178	1,178	1,178	1,178	1,178	1,178	1,178	1,178	1,178	1,178
Coal	2,240	1,275	1,275	1,275	1,275	147	147	147	147	147
Total	38,831	38,314	37,974	37,864	37,866	37,857	37,322	37,023	36,916	36,561
Surplus (Deficit)	**(2,514)**	**(4,162)**	**(5,810)**	**(7,395)**	**(8,446)**	**(9,605)**	**(11,105)**	**(12,155)**	**(12,830)**	**(13,738)**

[1/] Expected (1-in-2) load net of energy efficiency
[2/] Planning margin is 16% of load (this assumption was updated and set with the *2018 Northwest Regional Forecast*)
[3/] Firm hydro for capacity is the generation expected assuming critical peaking capability as determined by the utility sponsor.
[4/] Includes stand-alone storage resources

Table 4. Northwest Region Requirements and Resources – Summer Peak

The sum of the individual utilities' firm requirements and resources for a peak hour in August for each of the next 10 years are shown in this table. Firm peak requirements include a planning margin to account for planning uncertainties.

Megawatts	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Firm Requirements										
Load [1/]	31,732	32,742	33,853	35,052	36,204	37,230	38,239	39,150	39,868	40,239
Exports	1,632	1,628	2,045	2,285	1,961	2,239	1,626	1,626	1,626	1,626
Planning Margin [2/]	5,077	5,239	5,416	5,608	5,793	5,957	6,118	6,264	6,379	6,438
Total	38,441	39,609	41,314	42,945	43,959	45,426	45,983	47,040	47,873	48,304
Firm Resources										
Hydro [3/]	21,275	21,368	21,275	21,275	20,700	20,700	20,700	20,700	20,700	20,608
Demand Response	487	597	710	796	871	900	934	976	1,008	1,037
Small Thermal/Misc. [4/]	747	747	746	747	747	737	738	739	740	741
Natural Gas	6,173	7,235	7,492	7,492	7,492	7,492	8,554	8,554	8,554	8,554
Renewables-Other	460	460	437	437	433	433	433	422	410	408
Solar	757	626	599	593	582	567	574	564	543	536
Wind	1,031	1,006	1,009	992	984	970	972	975	960	955
Cogeneration	54	38	19	17	17	17	17	17	17	17
Imports	637	746	475	475	375	335	341	450	185	185
Nuclear	1,163	1,163	1,163	1,163	1,163	1,163	1,163	1,163	1,163	1,163
Coal	2,237	2,157	1,271	1,271	1,271	1,271	145	145	145	145
Total	35,021	36,144	35,196	35,258	34,635	34,584	34,571	34,705	34,424	34,349
Surplus (Deficit)	**(3,420)**	**(3,465)**	**(6,118)**	**(7,687)**	**(9,323)**	**(10,842)**	**(11,412)**	**(12,335)**	**(13,448)**	**(13,954)**

[1/] Expected (1-in-2) load net of energy efficiency
[2/] Planning margin is 16% of load (this assumption was updated and set with the *2018 Northwest Regional Forecast*)
[3/] Firm hydro for capacity is the generation expected assuming critical peaking capability as determined by the utility sponsor
[4/] Includes stand-alone storage resources

Northwest New and Existing Resources

Table 5. Recently Acquired Resources highlights projects that have recently become available.

Project	Fuel/Tech	Nameplate (MW)	Utility/Owner
River Road Generating Project Upgrade	Natural Gas		Clark PUD
Combine Hills 1	Wind	41	Clark PUD
2024 RFP Small Battery	Li Ion Storage	36	Idaho Power
Black Mesa Solar	Solar	40	Idaho Power
Black Mesa Battery	Li Ion Storage	40	Idaho Power
Coleman Hydro	Hydro	0.8	Idaho Power
Franklin Battery	Li Ion Storage	60	Idaho Power
Franklin Solar	Solar	100	Idaho Power
Hemingway Battery	Li Ion Storage	80	Idaho Power
Jackpot Solar	Solar	120	Idaho Power
7 Mile Solar, LLC (Oregon Schedule 126 - Community Solar Project Purchase Agreement (OR Sch. 126 CSP))	Solar	0.981	PacifiCorp
Antelope Creek Solar, LLC (OR Sch. 126 CSP)	Solar	2.25	PacifiCorp
Buckaroo Solar 1, LLC (OR Sch. 126 CSP)	Solar	2.4	PacifiCorp
Buckaroo Solar 2, LLC (OR Sch. 126 CSP)	Solar	2.99	PacifiCorp
Green Solar LLC (OR Sch. 126 CSP)	Solar	2.875	PacifiCorp
Linkville Solar, LLC (OR Sch. 126 CSP)	Solar	2.8	PacifiCorp
Orchard Knob Solar, LLC (OR Sch. 126 CSP)	Solar	2.25	PacifiCorp
Oregon Institute of Technology (OIT) Battery Energy Storage System	Li Ion Storage	2	PacifiCorp
Pine Grove Solar, LLC (OR Sch. 126 CSP)	Solar	1.4	PacifiCorp
Round Lake Solar, LLC (OR Sch. 126 CSP))	Solar	0.978	PacifiCorp
Skysol, LLC (Skysol Solar / 174 Power Global / Hanwha Group)	Solar	55	PacifiCorp
Sunset Ridge Solar, LLC (OR Sch. 126 CSP)	Solar	2.25	PacifiCorp
Clearwater Wind	Wind	311	Portland General Electric
Pachwaywit Solar	Solar	162	Portland General Electric
Short-Term Winter Market Energy Contract	Regional Contract	25	Snohomish PUD
Total (Nameplate)		**1,094**	

Table 6. Committed Resources details firm contracts and generating projects that are committed to come online. All supply listed in this table is included in the regional analysis of power needs.

Project	Year	Fuel/Tech	Nameplate (MW)	Utility/Owner
Yellowstone County Generating Station	2024	Natural Gas	175	NorthWestern Energy
Bakeoven	2025	Solar	60	Portland General Electric
Constable	2024	Li Ion Storage	75	Portland General Electric
Daybreak	2025	Solar	140	Portland General Electric
Seaside	2025	Li Ion Storage	200	Portland General Electric
Troutdale	2024	Li Ion Storage	200	Portland General Electric
Vantage Wind	2025	Wind	90	Puget Sound Energy
Total (Nameplate)			**1,134**	

Table 7. Demand-Side Management Programs is a snapshot of the regional utilities' efforts to manage demand. The majority of the energy efficiency savings are from utility programs and included in the regional analysis of power needs. This table also shows cumulative existing plus new demand response programs reported by utilities.

	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34
Energy Efficiency (aMW)										
Incremental	183	189	196	204	214	213	216	206	190	180
Cumulative	183	372	568	772	986	1,199	1,416	1,621	1,811	1,991
Demand Response (MW) existing + forecast[1]										
Winter	237	315	378	436	456	479	503	523	540	555
Summer	385	516	629	717	807	882	879	910	936	954

[1] Values are program effectiveness, nameplate values are higher.

Table 8. Planned Future Resources catalogues future resources that utilities have identified to meet their own needs. These resources are subject to change and are not included in the regional analysis of power needs.

Project	Year	Fuel/Tech	Nameplate	Utility
Generic Capacity	2025	Peaking Capacity	225	OR Utility
Utility-scale Renewables	2025	Renewable	50	WA Utility
E. Oregon Solar	2025	Solar PV	82	WA Utility
Palouse Junction	2025	Solar PV	10	WA Utility
Pilot Rock Solar 1, LLC (Community Solar)	2025	Solar PV	1.98	Multi-State Utility
Pilot Rock Solar 2, LLC (Community Solar)	2025	Solar PV	2.99	Multi-State Utility
Pleasant Valley Solar	2025	Solar PV	3	Multi-State Utility
Solar	2025	Solar PV	300	OR Utility
Solar	2025	Solar PV	80	OR Utility
Solar	2025	Solar PV	600	OR Utility
Solar	2025	Solar PV	41	OR Utility
Tutuilla Solar, LLC Community Solar)	2025	Solar PV	1.56	Multi-State Utility
2025 RFP Battery 1	2025	Storage	120	Multi-State Utility
2025 RFP Battery 2	2025	Storage	29	Multi-State Utility
25 MW 100 MWh Battery Energy Strorage	2025	Storage	25	WA Utility
Wind	2025	Wind	110	OR Utility
Wind	2025	Wind	201	OR Utility
Wind	2025	Wind	90	OR Utility
Wind	2025	Wind	151	OR Utility
Wind	2025	Wind	24	OR Utility
Solar + Storage	2026	Renewables + Storage	250	OR Utility
Wind + Solar + Battery	2026	Renewables + Storage	250	WA Utility
Oregon Solar	2026	Solar PV	74	WA Utility
Pleasant Valley Solar 2	2026	Solar PV	125	Multi-State Utility
Solar	2026	Solar PV	375	Multi-State Utility
Solar	2026	Solar PV	220	OR Utility
MT PHES	2026	Storage	200	WA Utility
Storage - Pumped Storage	2026	Storage	35	Multi-State Utility
WA/OR PHES	2026	Storage	200	WA Utility
Clearwater Wind PPA	2026	Wind	98	Multi-State Utility
Columbia River Gorge Wind	2026	Wind	200	WA Utility
MT Wind East	2026	Wind	400	WA Utility
Wind	2026	Wind	350	OR Utility
Wind	2026	Wind	350	OR Utility
Utility-scale Renewables	2027	Renewable	50	WA Utility
Solar + Storage	2027	Renewables + Storage	400	OR Utility
SE Oregon Solar	2027	Solar PV	200	WA Utility
Solar	2027	Solar PV	150	Multi-State Utility

Project	Year	Fuel/Tech	Nameplate	Utility
Washington Solar	2027	Solar PV	60	WA Utility
25 MW 100 MWh Battery Energy Storage	2027	Storage	25	WA Utility
4hr Storage	2027	Storage	5	Multi-State Utility
Wind	2027	Wind	400	Multi-State Utility
Utility-scale Renewables	2028	Renewable	50	WA Utility
Generic Solar	2028	Solar PV	150	WA Utility
4hr Storage	2028	Storage	5	Multi-State Utility
Generic Wind	2028	Wind	200	WA Utility
Wind	2028	Wind	400	Multi-State Utility
Post Falls Hydro Modernization	2029	Existing Resource Upgrade	8	Multi-State Utility
IRP Resource - Base Scenario	2029	Peaking Capacity	50	Multi-State Utility
Utility-scale Renewables	2029	Renewable	50	WA Utility
4hr Storage	2029	Storage	5	Multi-State Utility
Wind	2029	Wind	400	Multi-State Utility
Geothermal	2030	Renewable	30	Multi-State Utility
Solar	2030	Solar PV	500	Multi-State Utility
4hr Storage	2030	Storage	155	Multi-State Utility
Wind	2030	Wind	100	Multi-State Utility
Solar	2031	Solar PV	400	Multi-State Utility
4hr Storage	2031	Storage	5	Multi-State Utility
Wind	2031	Wind	400	Multi-State Utility
IRP Resource - Base Scenario	2032	Peaking Capacity	50	Multi-State Utility
Solar	2032	Solar PV	100	Multi-State Utility
4hr Storage	2032	Storage	205	Multi-State Utility
IRP Resource - Base Scenario	2032	Storage	100	Multi-State Utility
Wind	2032	Wind	100	Multi-State Utility
4hr Storage	2033	Storage	105	Multi-State Utility
IRP Resource - Base Scenario	2034	Peaking Capacity	18	Multi-State Utility
Natural Gas CT - for Idaho	2034	Peaking Capacity	90	Multi-State Utility
4hr Storage	2034	Storage	5	Multi-State Utility
Frame Peaker Biodiesel	2024 - 2028	Peaking Capacity	711	WA Utility
Solar + Battery	2024 - 2029	Renewables + Storage	450	WA Utility
WA East Solar	2024 - 2029	Solar PV	700	WA Utility
WA Wind	2024 - 2030	Wind	1000	WA Utility
Renewable - Utility Solar	2025 - 2027	Solar PV	1616	Multi-State Utility
Wind + Battery	2025 - 2029	Renewables + Storage	750	WA Utility
Renewable - Battery	2025 - 2029	Storage	3266	Multi-State Utility
DER Solar Ground (ground and rooftop)	2025 - 2033	Solar PV	270	WA Utility
Li-Ion 4hr	2025 - 2033	Storage	800	WA Utility
Preferred portfolio resource (Offshore wind)	2025 - 2034	Other Renewable	720	OR Utility
Preferred portfolio resource (solar & wind)	2025 - 2034	Renewable	2681	OR Utility
Preferred portfolo resource (CBRE)	2025 - 2034	Renewable	155	OR Utility

Project	Year	Fuel/Tech	Nameplate	Utility
Preferred portfolo resource (Hybrid solar + battery)	2025 - 2034	Renewables + Storage	1010	OR Utility
Preferred portfolio resource (storage)	2025 - 2034	Storage	864	OR Utility
DER Storage (BESS)	2027 - 2031	Storage	150	WA Utility
Renewable - Wind	2027 - 2033	Wind	2451	Multi-State Utility
WY East Wind	2031 - 2033	Wind	400	WA Utility
Preferred portfolio resource (capacity)	2031 - 2034	Peaking Capacity	205	OR Utility
Broadview (160MW Solar + 50MW Battery, 80 MW limit)	TBD	Renewables + Storage	160	Multi-State Utility
Meadowlark (20 MW Solar + 12.5MW Battery)	TBD	Renewables + Storage	20	Multi-State Utility
Trident (160 MW Solar + 80 MW Battery, 80 MW limit)	TBD	Renewables + Storage	160	Multi-State Utility
Jawbone	TBD	Wind	80	Multi-State Utility
TOTAL			**28,866**	

Table 9. Planned Future Resources Timeline displays the cumulative supply-side resource additions over time, combining the nameplate MW values of resources from Table 8 (NW utility owned/contracted only, IPP additions not included).

Nameplate MW	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Wind	1,176	2,574	3,074	3,674	4,074	4,574	5,174	6,443	7,825	7,905
Solar PV	1,262	3,210	4,133	4,513	4,943	5,473	5,903	6,033	6,063	6,063
Storage	558	3,021	4,004	4,934	5,164	5,344	5,689	6,094	6,299	6,304
Renewables + Storage	300	950	1,350	1,500	2,529	3,100	3,110	3,110	3,110	3,450
Offshore Wind	-	-	-	-	-	-	-	237	470	720
Renewables	119	516	995	1,470	1,849	1,911	3,066	3,066	3,066	3,066
Peaking Capacity	462	699	699	936	986	986	1,022	1,072	1,144	1,349
Existing Resource Upgrades	-	-	2	2	10	10	10	10	10	10
TOTAL	3,877	10,970	14,256	17,028	19,554	21,397	23,973	26,064	27,986	28,866

Table 10. Northwest Utility Generating Resources is a comprehensive list of utility-owned and utility contracted generating resources that make up those utilities electric power supply. This table includes recently acquired and committed resources – some of the resources listed may not currently be operating. Potential resources are not included in the table.

Project	Owner	NW Utility	Nameplate (MW)
HYDRO			**33,635**
Albeni Falls	US Corps of Engineers	Federal System (BPA)	43
Alder	Tacoma Power	Tacoma Power	50
American Falls	Idaho Power	Idaho Power	92
Anderson Ranch	US Bureau of Reclamation	Federal System (BPA)	40
Arena Drop	PURPA	Idaho Power	0.5
Arrowrock Dam	Clatskanie PUD/Irr Dist	Clatskanie PUD	18
Baker City Hydro	PURPA	Idaho Power	0.2
Barber Dam	PURPA	Idaho Power	4
Bend		PacifiCorp	1
Big Cliff	US Corps of Engineers	Federal System (BPA)	18
Big Fork		PacifiCorp	5
Big Sheep Creek	Everand Jensen	Avista Corp.	0.1
Birch Creek	PURPA	Idaho Power	0.1
Black Canyon	US Bureau of Reclamation	Federal System (BPA)	10
Black Canyon #3	PURPA	Idaho Power	0.1
Black Canyon Bliss Dam	PURPA	Idaho Power	0.03
Black Creek Hydro	Black Creek Hydro, Inc.	Puget Sound Energy	4
Black Eagle	NorthWestern Energy	NorthWestern Energy	23
Blind Canyon	PURPA	Idaho Power	2
Bliss	Idaho Power	Idaho Power	75
Boise River Diversion	US Bureau of Reclamation	Federal System (BPA)	2
Bonneville	US Corps of Engineers	Federal System (BPA)	1102
Boundary	Seattle City Light	Seattle City Light	1119
Box Canyon	Pend Oreille County PUD	Pend Oreille County PUD	90
Box Canyon-Idaho	PURPA	Idaho Power	0.4
Briggs Creek	PURPA	Idaho Power	1
Broadwater Dam	Dept. of Natural Res. & Cons.	NorthWestern Energy	10
Brownlee	Idaho Power	Idaho Power	585
Bypass	PURPA	Idaho Power	10
C. J. Strike	Idaho Power	Idaho Power	83
Cabinet Gorge	Avista Corp.	Avista Corp.	265
Calispel Creek	Pend Oreille County PUD	Pend Oreille County PUD	1
Calligan Creek	Snohomish County PUD	Snohomish County PUD	6
Canyon Springs	PURPA	Idaho Power	0.1
Carmen-Smith	Eugene Water & Electric Board	Eugene Water & Electric Board	105
Cascade	US Bureau of Reclamation	Idaho Power	12
Cedar Draw Creek	PURPA	Idaho Power	2
Cedar Falls, Newhalem	Seattle City Light	Seattle City Light	33
Chandler	US Bureau of Reclamation	Federal System (BPA)	12
Chelan	Chelan County PUD	Chelan County PUD	59
Chief Joseph	US Corps of Engineers	Federal System (BPA)	2457
Clackamas	Portland General Electric	Portland General Electric	96
Clear Lakes	Idaho Power	Idaho Power	3
Clear Springs Trout	PURPA	Idaho Power	1
Clearwater 1		PacifiCorp	18
Clearwater 2		PacifiCorp	31

Project	Owner	NW Utility	Nameplate (MW)
Cochrane	NorthWestern Energy	NorthWestern Energy	62
Coleman Hydro	PURPA	Idaho Power	1
Cougar	US Corps of Engineers	Federal System (BPA)	25
Cowlitz Falls	Lewis County PUD	Federal System (BPA)	70
Crystal Springs	PURPA	Idaho Power	2
Curry Cattle Company	PURPA	Curry Cattle Company	0.2
Cushman 1	Tacoma Power	Tacoma Power	43
Cushman 2	Tacoma Power	Tacoma Power	81
Deep Creek	Gordon Foster	Avista Corp.	0.5
Derr Creek	Jim White	Avista Corp.	0.3
Detroit	US Corps of Engineers	Federal System (BPA)	100
Dexter	US Corps of Engineers	Federal System (BPA)	15
Diablo	Seattle City Light	Seattle City Light	182
Dietrich Drop	PURPA	Idaho Power	5
Dworshak	US Corps of Engineers	Federal System (BPA)	400
Dworshak/ Clearwater		Federal System (BPA)	3
Ebey Hill	Ebey Hill Hydroelectric, Inc.	Snohomish County PUD	0.2
Eight Mile Hydro	PURPA	Idaho Power	0.4
Elk Creek	PURPA	Idaho Power	3
Eltopia Branch Canal	SEQCBID	Multiple Utilities	2
Esquatzel Small Hydro	Green Energy Today, LLC	Franklin County PUD	1
Falls River	PURPA	Idaho Power	9
Faraday	Portland General Electric	Portland General Electric	27
Fargo Drop Hydro	PURPA	Idaho Power	1
Faulkner Ranch	PURPA	Idaho Power	1
Fish Creek	PacifiCorp	PacifiCorp	10
Fisheries Development Co.	PURPA	Idaho Power	0.3
Foster	US Corps of Engineers	Federal System (BPA)	20
Gem State Hydro 1	IdahoFalls-ID		23
Geo-Bon #2	PURPA	Idaho Power	1
Gorge	Seattle City Light	Seattle City Light	207
Grand Coulee	US Bureau of Reclamation	Federal System (BPA)	6494
Green Peter	US Corps of Engineers	Federal System(BPA)	80
Green Springs	US Bureau of Reclamation	Federal System (BPA)	16
Hailey CSPP	PURPA	Idaho Power	0.1
Hancock Creek	Snohomish County PUD	Snohomish County PUD	6
Hauser	NorthWestern Energy	NorthWestern Energy	19
Hazelton A	PURPA	Idaho Power	8
Hazelton B	PURPA	Idaho Power	8
Head of U Canal	PURPA	Idaho Power	1
Hells Canyon	Idaho Power	Idaho Power	392
Hills Creek	US Corps of Engineers	Federal System (BPA)	30
Holter	NorthWestern Energy	NorthWestern Energy	50
Hood Street Reservoir	Tacoma Power	Tacoma Power	0.9
Horseshoe Bend	PURPA	Idaho Power	9
Hungry Horse	US Bureau of Reclamation	Federal System (BPA)	428
Ice Harbor	US Corps of Engineers	Federal System (BPA)	603
Idaho Falls - City Plant		Federal System (BPA)	8
Idaho Falls - Lower Plant #1		Federal System (BPA)	8
Idaho Falls - Lower Plant #2		Federal System (BPA)	3
Idaho Falls - Upper Plant		Federal System (BPA)	8

Project	Owner	NW Utility	Nameplate (MW)
Jackson (Sultan)	Snohomish County PUD	Snohomish County PUD	112
Jim Ford Creek	Ford Hydro	Avista Corp.	2
Jim Knight	PURPA	Idaho Power	0.3
John Day	US Corps of Engineers	Federal System (BPA)	2160
John Day Creek	Dave Cereghino	Avista Corp.	1
Koma Kulshan	Koma Kulshan Associates	Puget Sound Energy	12
Koyle Small Hydro	PURPA	Idaho Power	1
La Grande	Tacoma Power	Tacoma Power	64
Lake Oswego Corp.		Portland General Electric	1
Lateral #10	PURPA	Idaho Power	2
Lemolo 1	PacifiCorp	PacifiCorp	32
Lemolo 2	PacifiCorp	PacifiCorp	39
Lemoyne	PURPA	Idaho Power	0.1
Libby	US Corps of Engineers	Federal System (BPA)	525
Little Falls	Avista Corp.	Avista Corp.	32
Little Goose	US Corps of Engineers	Federal System (BPA)	810
Little Mac	PURPA	Idaho Power	1
Little Wood River Ranch II	PURPA	Idaho Power	1
Little Wood Rvr Res	PURPA	Idaho Power	3
Little Wood/Arkoosh	PURPA	Idaho Power	1
Long Lake	Avista Corp.	Avista Corp.	70
Lookout Point	US Corps of Engineers	Federal System (BPA)	120
Lost Creek	US Corps of Engineers	Federal System (BPA)	49
Low Line Canal	PURPA	Idaho Power	8
Low Line Midway	PURPA	Idaho Power	3
Lower Baker	Puget Sound Energy	Puget Sound Energy	115
Lower Granite	US Corps of Engineers	Federal System (BPA)	810
Lower Malad	Idaho Power	Idaho Power	14
Lower Monumental	US Corps of Engineers	Federal System (BPA)	810
Lower Salmon	Idaho Power	Idaho Power	60
Lower Swift Creek	Lower Valley Energy, Inc.	Other Publics (BPA)	0.4
Lowline #2	PURPA	Idaho Power	3
Lucky Peak	US Corps of Engineers	Seattle City Light	113
Madison	Northwestern Energy	NorthWestern Energy	8
Magic Reservoir	PURPA	Idaho Power	9
Main Canal Headworks	SEQCBID	Multiple Utilities	26
Malad River	PURPA	Idaho Power	1
Mayfield	Tacoma Power	Tacoma Power	162
MC6 Hydro	PURPA	Idaho Power	2
McNary	US Corps of Engineers	Federal System (BPA)	980
McNary Fishway	US Corps of Engineers	Other Publics (BPA)	10
Merwin	PacifiCorp	PacifiCorp	151
Meyers Falls	Hydro Technology Systems	Avista Corp.	1
Mile 28	PURPA	Idaho Power	2
Milner	Idaho Power	Idaho Power	118
Minidoka	US Bureau of Reclamation	Federal System (BPA)	28
Mitchell Butte	PURPA	Idaho Power	2
Monroe Street	Avista	Avista Corp.	15
Mora Drop	PURPA	Idaho Power	2
Morony	NorthWestern Energy	NorthWestern Energy	49
Mossyrock	Tacoma Power	Tacoma Power	300
Mount Tabor	City of Portland	Portland General Electric	0.2

Project	Owner	NW Utility	Nameplate (MW)
Moyie River 1	BonnersFerry-ID	Other Publics (BPA)	0.5
Moyie River 2	BonnersFerry-ID	Other Publics (BPA)	2
Moyie River 3	BonnersFerry-ID	Other Publics (BPA)	2
Mud Creek/S&S	PURPA	Idaho Power	1
Mud Creek/White	PURPA	Idaho Power	0.2
Mystic	NorthWestern Energy	NorthWestern Energy	12
N-32 Canal (Marco Ranches)	PURPA	Idaho Power	1
Nine Mile	Avista Corp.	Avista Corp.	26
Nooksack	Puget Sound Hydro, LLC	Puget Sound Energy	4
North Fork	Portland General Electric	Portland General Electric	27
North Gooding Main Hydro		Idaho Power	1
Noxon Rapids	Avista Corp.	Avista Corp.	466
Oak Grove	Portland General Electric	Portland General Electric	27
Owyhee Dam Cspp	PURPA	Idaho Power	5
Oxbow	Idaho Power Company	Idaho Power	190
Packwood	Energy Northwest	Multiple Utilities	28
Palisades	US Bureau of Reclamation	Federal System (BPA)	177
PEC Headworks	SEQCBID	Avista	7
Pelton	Portland General Electric	Multiple Utilities	110
Pelton Reregulation	Warm Springs Tribe	Portland General Electric	10
Pigeon Cove	PURPA	Idaho Power	2
Port Townsend Mill 2	PortTownsend Paper	Other Publics (BPA)	0.4
Portland Hydro-Project	City of Portland	Portland General Electric	36
Post Falls	Avista Corp.	Avista Corp.	15
Potholes East Canal 66 Headworks	SEQCBID	Seattle City Light	2
Priest Rapids	Grant County PUD	Multiple Utilities	956
Pristine Springs #1	PURPA	Idaho Power	0.1
Pristine Springs #3	PURPA	Idaho Power	0.2
Prospect 1		PacifiCorp	5
Prospect 2		PacifiCorp	36
Prospect 3		PacifiCorp	8
Prospect 4		PacifiCorp	1
QF- CA		PacifiCorp	9
QF- OR		PacifiCorp	40
QF- WA		PacifiCorp	3
Quincy Chute	SEQCBID	Multiple Utilities	9
R.D. Smith	SEQCBID	Multiple Utilities	6
Rainbow	NorthWestern Energy	NorthWestern Energy	64
Reynolds Irrigation	PURPA	Idaho Power	0.3
River Mill	Portland General Electric	Portland General Electric	15
Rock Creek #1	PURPA	Idaho Power	2
Rock Creek #2	PURPA	Idaho Power	2
Rock Island	Chelan County PUD	Multiple Utilities	629
Rocky Reach	Chelan County PUD	Multiple Utilities	1300
Ross	Seattle City Light	Seattle City Light	450
Round Butte	Portland General Electric	Multiple Utilities	338
Roza	US Bureau of Reclamation	Federal System (BPA)	13
Ryan	NorthWestern Energy	NorthWestern Energy	72
Sagebrush	PURPA	Idaho Power	0.4
Sahko	PURPA	Idaho Power	1
Schaffner	PURPA	Idaho Power	1

Project	Owner	NW Utility	Nameplate (MW)
Sheep Creek	Glen Phillips	Avista Corp.	2
Shingle Creek	PURPA	Idaho Power	0.2
Shoshone #2	PURPA	Idaho Power	1
Shoshone CSPP	PURPA	Idaho Power	0.4
Shoshone Falls	Idaho Power	Idaho Power	14
Skookumchuck	-	Puget Sound Energy	1
Slide Creek	PacifiCorp	PacifiCorp	18
Smith Creek	Smith Creek Hydro, LLC	Eugene Water & Electric Board	0.1
Snake River Pottery	PURPA	Idaho Power	0.1
Snedigar Ranch	PURPA	Idaho Power	1
Snoqualmie Falls	Puget Sound Energy	Puget Sound Energy	54
Soda Springs	PacifiCorp	PacifiCorp	12
South Fork Tolt	Seattle City Light	Seattle City Light	17
Spokane Upriver	City of Spokane	Avista Corp.	16
Stone Creek	Eugene Water & Electric Board	Eugene Water & Electric Board	12
Strawberry Creek Wyoming 1	Lower Valley Energy	Other Publics (BPA)	2
Summer Falls	SEQCBID	Multiple Utilities	92
Swan Falls	Idaho Power	Idaho Power	25
Swift 1	PacifiCorp	Multiple Utilities	219
Swift 2	Cowlitz County PUD	Multiple Utilities	77
Sygitowicz	Cascade Clean Energy	Puget Sound Energy	0.4
The Dalles	US Corps of Engineers	Federal System (BPA)	1807
The Dalles North Fishway	Northern Wasco County PUD	Other Publics (BPA)	5
Thompson Falls Dam	Northwestern Energy	Northwestern Energy	94
Thousand Springs	Idaho Power	Idaho Power	9
Toketee	PacifiCorp	PacifiCorp	45
Trail Bridge	Eugene Water & Electric Board	Eugene Water & Electric Board	10
Trout Co	PURPA	Idaho Power	0.2
Tunnel #1	PURPA	Idaho Power	7
Turnbull Hydro		NorthWestern Energy	13
TW Sullivan	Portland General Electric	Portland General Electric	15
Twin Falls	PURPA	Puget Sound Energy	53
Twin Falls	PURPA	Puget Sound Energy	20
Upper Baker	Puget Sound Energy	Puget Sound Energy	105
Upper Falls	Avista Corp.	Avista Corp.	10
Upper Malad	Idaho Power	Idaho Power	8
Upper Salmon A	Idaho Power	Idaho Power	18
Upper Salmon B	Idaho Power	Idaho Power	17
Upper Swift Creek	Lower Valley Energy	Other Publics (BPA)	1
Walla Walla 1	Columbia REA	Other Publics (BPA)	2
Wallowa Falls	PacifiCorp	PacifiCorp	1
Walterville	Eugene Water & Electric Board	Eugene Water & Electric Board	8
Wanapum	Grant County PUD	Multiple Utilities	934
Weeks Falls	So. Fork II Assoc. LP	Puget Sound Energy	5
Wells	Douglas County PUD	Multiple Utilities	774
White Water Ranch	PURPA	Idaho Power	0.2
Whitefish Hydro		Ftathead Electric Cooperative	0.2
Wilson Lake		Other Publics (BPA)	8
Woods Creek	Snohomish County PUD	Snohomish County PUD	1
Wynoochee	Tacoma Power	Tacoma Power	13
Yakama Drop 2	Yakama Power		3
Yakama Drop 3	Yakama Power		2

Project	Owner	NW Utility	Nameplate (MW)
Yale	PacifiCorp	PacifiCorp	164
Yelm 1		Other Publics (BPA)	12
Youngs Creek	Snohomish County PUD	Snohomish County PUD	8
COAL			**2,792**
Colstrip #3	Talen Energy/Multiple Utilities	Multiple Utilities	740
Colstrip #4	Talen Energy/Multiple Utilities	Multiple Utilities	740
Jim Bridger #3	PacifiCorp / Idaho Power	Multiple Utilities	521
Jim Bridger #4	PacifiCorp / Idaho Power	Multiple Utilities	524
Valmy #2	NV Energy / Idaho Power	Multiple Utilities	267
NUCLEAR			**1,230**
Columbia Generating Station	Energy Northwest	Federal System (BPA)	1,230
NATURAL GAS			**8,315**
Basin Creek	NorthWestern Energy	NorthWestern Energy	52
Beaver	Portland General Electric	Portland General Electric	509
Bennett Mountain	Idaho Power	Idaho Power	179
Boulder Park	Avista Corp.	Avista Corp.	25
Carty	Portland General Electric	Portland General Electric	437
Chehalis Generating Facility	PacifiCorp	PacifiCorp	491
Coyote Springs I	Portland General Electric	Portland General Electric	252
Coyote Springs II	Avista Corp.	Avista Corp.	287
Danskin	Idaho Power	Idaho Power	90
Danskin 1	Idaho Power	Idaho Power	179
Dave Gates Generating Station	NorthWestern Energy	NorthWestern Energy	150
Encogen	Puget Sound Energy	Puget Sound Energy	166
Ferndale	Puget Sound Energy	Puget Sound Energy	244
Frederickson Generation Station	EPCOR Power L.P./PSE	Multiple Utilities	258
Fredonia 1 & 2	Puget Sound Energy	Puget Sound Energy	234
Fredonia 3 & 4	Puget Sound Energy	Puget Sound Energy	108
Fredrickson 1 & 2	Puget Sound Energy	Puget Sound Energy	149
Goldendale Generating Station	Puget Sound Energy	Puget Sound Energy	280
Hermiston Generating Project	PacifiCorp/Hermiston Generating Co.	PacifiCorp	468
Jim Bridger #1	PacifiCorp / Idaho Power	Multiple Utilities	528
Jim Bridger #2	PacifiCorp / Idaho Power	Multiple Utilities	536
Kettle Falls CT	Avista Corp.	Avista Corp.	7
Lancaster Power Project	Avista Corp.	Avista Corp.	270
Langley Gulch	Idaho Power	Idaho Power	321
Mint Farm Energy Center	Puget Sound Energy	Puget Sound Energy	276
Northeast A&B	Avista Corp.	Avista Corp.	62
Port Westward	Portland General Electric	Portland General Electric	411
Port Westward Unit 2	Portland General Electric	Portland General Electric	225
Rathdrum 1 & 2	Avista Corp.	Avista Corp.	167
River Road Generating Project	Clark Public Utilities	Clark Public Utilities	248
Sumas Energy	Puget Sound Energy	Puget Sound Energy	129
Valmy #1	NV Energy / Idaho Power	Multiple Utilities	254
Whitehorn #2 & 3	Puget Sound Energy	Puget Sound Energy	149

Project	Owner	NW Utility	Nameplate (MW)
Yellowstone County Generating Station	NorthWestern Energy	NorthWestern Energy	175
COGENERATION			**55**
Hampton Lumber	Hampton Lumber Mills	Snohomish County PUD PPA	5
International Paper Energy Center	Eugene Water & Electric Board	Eugene Water & Electric Board	26
Port Townsend Mill	Port Townsend Paper	BPA (other publics)	8
Simplot-Pocatello	PURPA	Idaho Power	12
Tasco-Nampa	Tasco	Idaho Power	2
Tasco-Twin Falls	Tasco	Idaho Power	3
RENEWABLES-OTHER			**401**
Bannock County Landfill	PURPA	Idaho Power	3
Bettencourt Dry Creek	PURPA	Idaho Power	2
Biomass One	PacifiCorp	PacifiCorp	25
Bloks Evergreen Dairy	Puget Sound Energy	Puget Sound Energy	0.2
DR Johnson Lumber	PacifiCorp	PacifiCorp	8
Columbia Ridge Landfill	Waste Management	Seattle City Light	13
Dry Creek Landfill	Dry Creek Landfill Inc.	PacifiCorp	3
Emerald City I		Puget Sound Energy	5
Emerald City II		Puget Sound Energy	5
Fighting Creek	PURPA	Idaho Power	3
Flathead County Landfill	Flathead Electric Cooperative	Flathead Electric Cooperative	2
Hidden Hollow Landfill	PURPA	Idaho Power	3
H. W. Hill Landfill	Allied Waste Companies	Multiple Utilities	37
Interfor Pacific-Gilchrist	Midstate Electric Co-op	Midstate Electric Co-op	2
Kettle Falls	Avista Corp.	Avista Corp.	51
Neal Hot Springs	U.S Geothermal	Idaho Power	33
Pico Energy, LLC	PURPA	Idaho Power	2
Pine Products	PacifiCorp	PacifiCorp	6
Plum Creek NLSL	Plum Creek MDF	Flathead Electric Cooperative	6
Pocatello Wastewater	PURPA	Idaho Power	0.5
Port of Tillamook Digester		Tillamook PUD	1
PGE non solar QFs		Portland General Electric	73
Qualco Dairy Digester		Snohomish PUD	0.7
Raft River 1	US Geothermal	Idaho Power	16
River Bend Landfill	McMinnville Water & Light	McMinnville Water & Light	5
Rock Creek Dairy	PURPA	Idaho Power	3
Seneca	Seneca Sustainable Energy, LLC	Eugene Water & Electric Board	20
Short Mountain		Emerald PUD	3
Sierra Pacific		Grays Harbor	16
SPI Biomass		Puget Sound Energy	17
Spokane Waste Energy	City of Spokane	Avista Corp.	26
Stimson Lumber	Stimson Lumber	Avista	7
Stoltze Biomass	F.H. Stoltze Land & Lumber	Flathead Electric Cooperative	3
Tamarack	PURPA	Idaho Power	5
SOLAR			**2,073**
7 Mile Solar, LLC	Community Solar OR Sch 126	PacifiCorp	1
Adams Solar Center		PacifiCorp	10
American Falls Solar	PURPA	Idaho Power	20

Project	Owner	NW Utility	Nameplate (MW)
American Falls Solar II	PURPA	Idaho Power	20
Antelope Creek Solar, LLC	Community Solar OR Sch 126	PacifiCorp	2
Ashland Solar Project		BPA	0.1
Baker Solar	PURPA	Idaho Power	15
Bear Creek		PacifiCorp	10
Bellevue Solar	EDF Renewable Energy	Portland General Electric	1
Black Cap		PacifiCorp	2
Black Cap II		PacifiCorp	8
Black Eagle Solar		NorthWestern Energy	3
Bly Solar Center		PacifiCorp	8
Brush Solar	PURPA	Idaho Power	3
Buckaroo Solar 1, LLC	Community Solar OR Sch 126	PacifiCorp	2
Buckaroo Solar 2, LLC	Community Solar OR Sch 126	PacifiCorp	3
Captain Jack Solar		PacifiCorp	3
CC Solar 1		PSE	0.01
CC Solar 2		PSE	0.01
Cleanera Apex I		NorthWestern Energy	80
OSLH Collier	Portland General	PacifiCorp	10
Daybreak Solar	Portland General	Portland General Electric	138
Durkee Solar	PURPA	Idaho Power	3
Elbe		PacifiCorp	10
Finn Hill Solar (Lake Wash SD)		Puget Sound Energy	0.4
Franklin Solar		Idaho Power	100
Grand View Solar	PURPA	Idaho Power	80
Great Divide Solar		NorthWestern Energy	3
Green Meadows Solar		NorthWestern Energy	3
Green Solar LLC	Community Solar OR Sch 126	PacifiCorp	3
Grove Solar	PURPA	Idaho Power	6
Horn Rapids		Energy Northwest	3
Hyline Solar Center	PURPA	Idaho Power	9
ID Solar 1	Boise City Solar, LLC	Idaho Power	40
IKEA Solar		Puget Sound Energy	1
Ivory		PacifiCorp	10
Jackpot Solar	Jackpot Holdings, LLC	Idaho Power	120
King Estate Solar	Lane Co. Electric Cooperative	Lane Co. Electric Cooperative	0.2
Linkville Solar, LLC	Community Solar OR Sch 126	PacifiCorp	3
Lund Hill	Lane Co. Electric Cooperative	Puget Sound Energy	150
Magpie Solar		NorthWestern Energy	3
Merrill Solar LLC		PacifiCorp	10
Millican Solar Energy		PacifiCorp	59
Morgan Solar	PURPA	Idaho Power	3
Mountain Home Solar	PURPA	Idaho Power	20
Moyer-Tolles Solar	Umatilla Electric Cooperative	Umatilla Electric Cooperative	1
MTSun LLC		NorthWestern Energy	80
Murphy Flat Power	PURPA	Idaho Power	20
Neilson Solar		Avista	19
Norwest Projects		PacifiCorp	31
Old Mill		PacifiCorp	5
Open Range Solar Center	PURPA	Idaho Power	10
OR Solar projects		PacifiCorp	64
Orchard Knob Solar, LLC	Community Solar OR Sch 126	PacifiCorp	2

Project	Owner	NW Utility	Nameplate (MW)
Orchard Ranch Solar	PURPA	Idaho Power	20
Oregon Community Solar Program	Various	0	37
OSIP		PacifiCorp	9
Pachwáywit Solar		Portland General Electric	162
PGE Solar QF		Portland General Electric	403
Pine Grove Solar, LLC	Community Solar OR Sch 126	PacifiCorp	1
Prineville		PacifiCorp	39
PSE Small Solar (5 projects)		Puget Sound Energy	15
Railroad Solar Center	PURPA	Idaho Power	5
River Bend Solar		NorthWestern Energy	2
Round Lake Solar, LLC	Community Solar OR Sch 126	PacifiCorp	1
Simco Solar	PURPA	Idaho Power	20
Skysol Solar		PacifiCorp	54
Solarize Rogue LLC	Oregon Clean Power	PacifiCorp	0.1
South Mills Solar 1		NorthWestern Energy	3
Sunnyside Solar	OneEnergy Renewables	PacifiCorp	5
Sunset Ridge Solar, LLC	Community Solar OR Sch 126	PacifiCorp	2
Thunderegg Solar Center	PURPA	Idaho Power	10
Tumbleweed		PacifiCorp	10
Vale Air Solar	PURPA	Idaho Power	10
Vale I Solar	PURPA	Idaho Power	3
Wallowa County		PacifiCorp	0.4
Wheatridge Solar	Portland General/Nextera Energy	Portland General Electric	50
Wild Horse Solar Project	Puget Sound Energy	Puget Sound Energy	1
Yamhill Solar	EDF Renewable Energy	Portland General Electric	1
WIND			**6,211**
71 Ranch LP		NorthWestern Energy	3
Bennett Creek	PURPA	Idaho Power	21
Benson Creek Wind	PURPA	Idaho Power	10
Big Timber Wind		NorthWestern Energy	25
Biglow Canyon - 1	Portland General Electric	Portland General Electric	125
Biglow Canyon - 2	Portland General Electric	Portland General Electric	163
Biglow Canyon - 3	Portland General Electric	Portland General Electric	161
Burley Butte Wind Farm	PURPA	Idaho Power	21
Camp Reed Wind Park	PURPA	Idaho Power	23
Cassia Wind Farm	PURPA	Idaho Power	11
Chopin		PacifiCorp	10
Clearwater PSE	NextEra	Multiple Utilities	661
Coastal Energy Project	CCAP	Grays Harbor PUD	6
Cold Springs	PURPA	Idaho Power	23
Combine Hills I	Eurus Energy of America	Clark Public Utilities	41
Combine Hills II	Eurus Energy of America	Clark Public Utilities	63
Condon Wind	Allete	Seattle City Light	50
Cycle Horseshoe Bend Wind		NorthWestern Energy	9
DA Wind Investors		NorthWestern Energy	3
Desert Meadow Windfarm	PURPA	Idaho Power	23
Durbin Creek	PURPA	Idaho Power	10
Elkhorn Wind	Telocaset Wind Power Partners	Idaho Power	101
Fairfield Wind		NorthWestern Energy	10
Fossil Gulch Wind	PURPA	Idaho Power	11

Project	Owner	NW Utility	Nameplate (MW)
Golden Hills	Avangrid	Puget Sound Energy	200
Golden Valley Wind Farm	PURPA	Idaho Power	12
Goodnoe Hills	PacifiCorp	PacifiCorp	94
Gordon Butte Wind		NorthWestern Energy	10
Greenfield Wind		NorthWestern Energy	25
Hammett Hill Windfarm		Idaho Power	23
Harvest Wind	Summit Power	Multiple Utilities	99
Hay Canyon Wind (confidential)	Hay Canyon Wind Project LLC (Iberdrola)	Snohomish County PUD	101
High Mesa Wind	PURPA	Idaho Power	40
Hopkins Ridge	Puget Sound Energy	Puget Sound Energy	157
Horseshoe Bend	PURPA	Idaho Power	9
Hot Springs Wind	Hot Springs Wind	Idaho Power	21
Jett Creek	PURPA	Idaho Power	10
Judith Gap	Invenergy Wind, LLC	NorthWestern Energy	135
Klondike II	PPM Energy	Portland General Electric	75
Klondike III	PPM Energy	Multiple Utilities	221
Leaning Juniper	PPM Energy	PacifiCorp	101
Lime Wind Energy	PURPA	Idaho Power	3
Lower Snake River 1	Puget Sound Energy	Puget Sound Energy	343
Mainline Wind Farm	PURPA	Idaho Power	23
Marengo	Renewable Energy America	PacifiCorp	140
Marengo II	PacifiCorp	PacifiCorp	70
Mariah Wind		PacifiCorp	10
Milner Dam Wind Farm	PURPA	Idaho Power	20
Musselshell Wind 1		NorthWestern Energy	10
Musselshell Wind 2		NorthWestern Energy	10
Nine Canyon	Energy Northwest	Multiple Utilities	96
Orchard Wind		PacifiCorp	40
Oregon Trails Wind Farm	PURPA	Idaho Power	14
Oregon Wind Farms I & II		PacifiCorp	65
Orem Family Wind		PacifiCorp	10
Oversight Resources		NorthWestern Energy	3
Palouse Wind	Palouse Wind, LLC	Avista Corp.	105
Paynes Ferry Wind Park	PURPA	Idaho Power	21
Pilgrim Stage Station Wind Farm	PURPA	Idaho Power	11
Prospector Wind	PURPA	Idaho Power	10
Rattlesnake Flat Wind		Avista Corp.	146
Rockland Wind	PURPA	Idaho Power	80
Ryegrass Windfarm	PURPA	Idaho Power	23
Salmon Falls Wind Farm	PURPA	Idaho Power	22
Sawtooth Wind	PURPA	Idaho Power	22
Skookumchuck	Puget Sound Energy	Puget Sound Energy	137
South Peak Wind		NorthWestern Energy	80
Spion Kop Wind		NorthWestern Energy	40
Stateline Wind	NextEra	Multiple Utilities	275
Stillwater Wind		NorthWestern Energy	80
Thousand Springs Wind Farm	PURPA	Idaho Power	12
Three Mile Canyon	Momentum RE	PacifiCorp	10
Tuana Gulch Wind Farm	PURPA	Idaho Power	11
Tuana Springs Expansion Wind	PURPA	Idaho Power	36

Project	Owner	NW Utility	Nameplate (MW)
Tucannon	Portland General Electric	Portland General Electric	267
Two Dot Wind		NorthWestern Energy	11
Two Ponds Windfarm	PURPA	Idaho Power	23
Vansycle Ridge	ESI Vansycle Partners	Portland General Electric	24
Vantage	Invenergy Wind NA, LLC	Puget Sound Energy	90
Wheat Field Wind Project (confidential)	Wheat Field Wind LLC (Horizon Energy/EDP)	Snohomish County PUD	97
Wheatridge Wind Project	PGE/Nextera Energy	Portland General Electric	300
White Creek	White Creek Wind I LLC	Multiple Utilities	205
Wild Horse	Puget Sound Energy	Puget Sound Energy	273
Willow Spring Windfarm	PURPA	Idaho Power	10
Yahoo Creek Wind Park	PURPA	Idaho Power	21
SMALL THERMAL AND MISCELLANEOUS			**236**
Colstrip Energy LP Coal	Colstrip Energy Limited Partnership	Northwestern Energy	35
Crystal Mountain	Puget Sound Energy	Puget Sound Energy	3
PGE DSG	Various	Portland General Electric	135
Puget Sound Shipyard	U.S. Navy-Bangor	BPA/Other publics	12
Yellowstone Energy LP	NRF	Northwestern Energy	52
STORAGE			**618**
Constable	Portland General Electric	Portland General Electric	75
Hemingway Battery	Idaho Power	Idaho Power	80
IPC 2024 RFP Small Battery	Idaho Power	Idaho Power	36
Oregon Institute of Technology BESS	OIT	PacifiCorp	2
Seaside Battery	Portland General Electric	Portland General Electric	200
SnoPUD 25 MW Battery	Snohomish PUD	Snohomish PUD	25
Troutdale Battery	Portland General Electric	Portland General Electric	200
Total Generating Resources			**55,567**

Report Description

This report provides a regional firm needs estimate over the ten-year study period for annual energy (August through July, *Table 1*), monthly energy (*Table 2*), winter peak-hour (*Table* 3) and summer peak-hour (*Table 4*). The monthly energy picture is provided to underscore the variability of the power need within an average year. The peak need reflects information for January and August, as they present the greatest need for their respective seasons. These metrics provide a multi-dimensional look at the Northwest's need for power and underscore the growing complexity of the power system.

This information reflects the summation of individual utilities' load forecasts and generating resources expected to meet their load, as well as the total of utilities committed and planned resources to meet future needs and policy requirements. The larger utilities, in most cases, prepare their own projections for their integrated resource plans and planning studies. Bonneville Power Administration (BPA) provides much of the information for its smaller customers. This section includes procedures used in preparing the load resource comparisons, a list of definitions, and a list of the utilities summarized by this report (*Table 11*).

Load Estimate

Regional loads are the sum of demand estimated by the Northwest utilities and BPA for its federal agency customers and certain non-generating public utilities. Direct service industrial customers are no longer a significant part of regional load. Utilities are asked to provide their native load forecast. Load projections include network transmission and distribution losses and are net of existing and forecasted energy efficiency savings (including codes & standards). Demand response program savings are not reflected in loads, rather they are included on the supply side in this report. Since the *Forecast* is completed annually, utilities may provide load forecasts that are updated and out of sync with their last resource plan.

Energy Loads

Northwest firm energy loads are provided for each month of the ten-year forecast period. This forecast reflects normal (1-in-2) weather conditions.

Peak Loads

Northwest regional peak loads are provided for each month of the ten-year forecast period. The tabulated loads for winter and summer peak are the highest estimated hourly loads for that month, assuming normal (1-in-2) weather conditions. The regional firm peak load is the sum of the individual utilities' peak loads and does not account for a utility potentially experiencing a peak load at a different day/hour than other Northwest utilities. Hence the regional peak load is considered non-coincident. The federal system (BPA) firm peak load is adjusted to reflect a federal coincident peak among its many utility customers.

Federal System Transmission Losses

Federal System (BPA) transmission losses for both firm loads and contractual obligations are embedded in federal load. These losses represent the difference between energy generated by the federal system (or delivered to a system interchange point) and the amount of energy sold to customers. System transmission losses are calculated by BPA for firm loads utilizing the federal transmission system.

Planning Margin

In the derivation of regional peak requirements, a planning margin is included. The planning margin is set to 16 percent of the total peak load for every year of the planning horizon.[1]

This planning margin is intended to cover, for planning purposes, operating reserves and all elements of uncertainty not specifically accounted for in determining loads and resources. These include forced-outage reserves, unanticipated load growth, temperature variations, hydro maintenance, and project construction delays.

Demand-Side Management Programs

Savings from demand-side management (*Table 7*) are for the ten-year study period and include data provided by utilities such as utility energy efficiency programs, some market transformation, and other efforts that reduce the demand for electricity. These estimates reflect savings from programs that utilities fund directly, or through a third-party, such as the Northwest Energy Efficiency Alliance and Energy Trust of Oregon.

Demand response programs are also tallied on *Table 7* showing the programs' winter peak and summer peak contributions to need. The regional demand response data is from the cumulative sum of all utilities' agreements with their customers (for both existing and future programs). Each program has its own characteristics and limitations that are reflected in the data provided.

Generating Resources

This report catalogues existing resources, committed new supply (including resources under construction), and planned future resources. For the assessment of need, only the existing and committed resources are reflected in the regional tabulations. In addition, only those generating resources (or shares) that are firmly committed to meeting Northwest loads are included in the regional analysis. A list of all resources included in the report load/resource tabulations is in *Table 10*.

[1] When making comparisons to *Northwest Regional Forecasts* prior to 2018, be aware that the planning margin was previously set at 12 percent for the first year of the report and grew a percent a year until it reached 20 percent and remained at 20 percent thereafter. This escalation was in part to address uncertainty of planning for generating resources with long planning and construction lead times.

Hydro

Major hydro resource capabilities are estimated from a regional analysis using computer models that simulate reservoir operation of past hydrologic conditions with today's operating constraints and requirements. The historical stream flow record used covers the 90-year period from August 1928 through July 2018. The bulk of the hydro modeling used in this report is provided by BPA, the US Army Corps of Engineers, and/or project owners/sponsors.

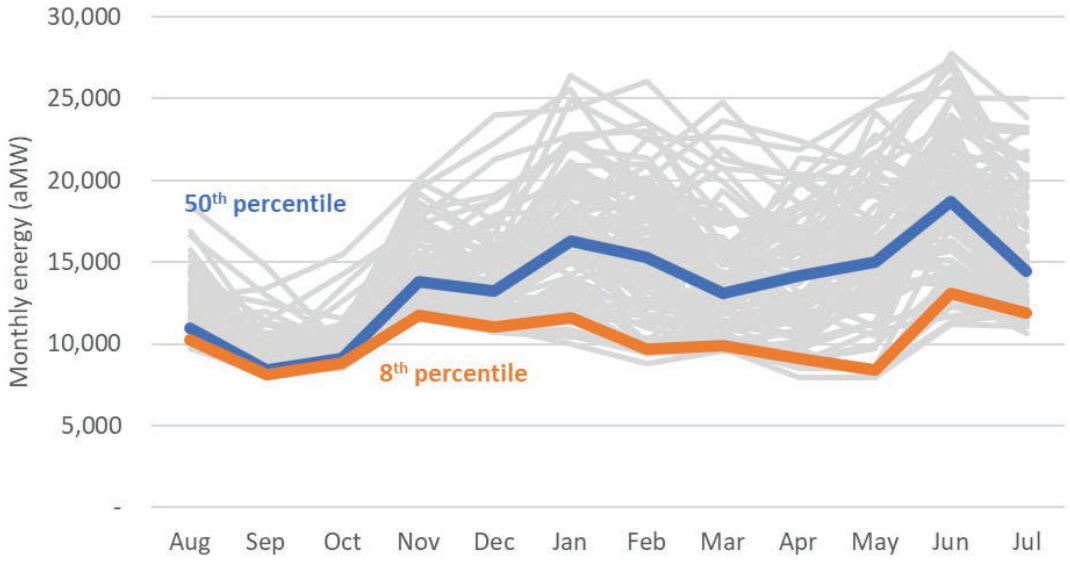
Annual and Monthly Energy

The bulk of the hydro energy data in this report comes from the US Army Corps of Engineers. Generation for projects that are influenced by downstream reservoirs reflects the reduction due to encroachment. New this year, the firm energy capability of hydro plants is the amount of energy produced using the 8th percentile monthly energy production from the 90-year historical river flow given today's river operating criteria. This provides an updated view of the critically low value for planning. The firm annual energy capability is the average of the 8th percentile monthly generation for the 90-year period. This synthetic water year ensures each month and year are evaluated similarly and under critically low streamflow.

Variability of Hydro

The variability of hydro generation is due to the hydrology of the river systems in the Northwest. Monthly hydro energy generation estimates from the major developments in the coordinated hydro system are shown for each of the 90 different river flow conditions using current system operating criteria in Figure 10. For perspective, the 50th percentile and 8th percentile. The 8th percentile monthly energy difference is indistinguishable between the 80-year and 90-year historical river flows.

Figure 10. Monthly Hydro Generation Across 90-year historical record



Peak Capability

For this report the peak capability of the hydro system represents maximum sustained hourly generation available to meet peak demand during the period of heavy load. Hydro-project owners submit a sustained peak capability for each project.[2] The bulk of the peak data in this report come from BPA. BPA has updated its critical peak planning from 1936-37 to the 10th percentile from the most recent 30-year historical record for water conditions. This increased the Federal system winter hydropower peaking capability and slightly reduced summer peaking capability.

The peaking capability of the hydro system maximizes available energy and capacity associated with the monthly distribution of streamflow. The peaking capability is the hydro system's ability to continuously produce power for a specific time period by utilizing the limited water supply while meeting power and non-power requirements, scheduled maintenance, and operating reserves.

Columbia River Treaty

Since 1961 the United States has had a treaty with Canada that outlines the operation of U.S. and Canadian storage projects to increase the total combined generation. Hydropower generation in this analysis reflects the firm power generated by coordinating operation of three Canadian reservoirs, Duncan, Arrow and Mica with the Libby reservoirs and other power facilities in the region. Canada's share of the coordinated operation benefits is called Canadian Entitlement. BPA and each of the non-Federal mid-Columbia project owners are obligated to return their share of the downstream power benefits owed to Canada. The delivery of the Entitlement is reflected in this analysis and makes up the bulk of the region's exports in this year's report.

Downstream Fish Migration

Another requirement incorporated in the hydro modeling are modified river operations to provide for the downstream migration of anadromous fish. These modifications include adhering to specific flow limits at some projects, spilling water at several projects, and augmenting flows in the spring and summer on the Columbia, Snake and Kootenai rivers. Specific requirements are defined by various federal, regional and state mandates, such as project licenses, biological opinions and state regulations.

Thermal and Renewable Resources

Thermal resources are reported in a variety of categories including coal, natural gas, nuclear and other. Other includes cogeneration, diesel and oil.

Renewable resources other than hydropower are categorized as solar, wind and other renewables and are each totaled and reported separately. Other renewables include energy from biomass, geothermal, municipal solid waste projects, and other projects.

[2] Historically, a 50-hour sustained peak (10 hours/day for 5 days) was reported. Project owners/sponsors use a variety of peak capability metrics today.

All existing generating plants, regardless of size, are included in amounts submitted by each utility that owns or is purchasing the generation. The energy and peaking capabilities of plants are submitted by the projects' owners and take into consideration scheduled maintenance (including refueling), forced outages, and other expected operating constraints. Some small thermal plants and combustion turbines are included as peaking resources and their reported energy capabilities are only the amounts necessary for peaking operations. Additional energy may be available from these peaking resources but is not included in the regional energy load/resource balance.

Battery Storage

In recent years battery storage resources have made their way into the region's resource mix, with a relatively large amount planned in the next 10 years. Battery storage is showing up as a standalone resource and in combination with solar and wind generation. It is reflected as supply during the peak hour of the month.

New and Future Resources

The latest activity with new and future resource developments, including expected savings from demand-side management actions, are tabulated in this report. These resources are reported as recently acquired, committed new supply, and planned future resources to reflect the different stages of development.

Recently Acquired Resources

The Recently Acquired Resources reported in *Table 5* have been acquired and will be serving Northwest utility loads as of December 31, 2023. They are reflected as part of the regional firm needs assessment.

Committed New Supply

Committed New Supply reported in *Table 6* includes projects under construction or firmly committed to meet Northwest load that are not delivering power as of December 31, 2023. These resources are included in the regional load-resource analysis. Future energy efficiency and demand response programs are included in the load-resource analysis as well (see *Table 7*).

Planned Future Resources

Planned Future Resources presented in *Table 8* includes specific resources and/or blocks of generic resources identified in utilities' most current integrated resource plans and planning studies. Projects in *Planned Future Resources* are not yet under construction, are not part of the regional analysis, and are subject to change until the time for acquiring them is closer. As the resource build date nears, more information about these resources will likely become available, and they typically move into the *Committed New Supply* category prior to coming online. Often, the utility will undergo a request for

proposal process before moving a resource from *Planned* to *Committed.* Resources in this category are *referred to as Potential Resources* in some previous *Northwest Regional Forecasts*.

Contracts

Imports and exports include firm arrangements for trade with systems outside the region, as well as with third-party developers/owners within the region. These arrangements comprise firm contracts with utilities to the East, in California and Canada. Contracts to and from these areas are amounts delivered at the area border and include transmission losses associated with deliveries.

Long-term intraregional contracts between Northwest utilities net to zero in the regional picture and consequently are not tallied for this report. In addition, short-term and/or spot purchases from Northwest independent power producers and from out-of-region are not reflected in the tables that present the firm load resource comparisons in this report.

Non-Firm Resources

The *Northwest Regional Forecast* omits from the load/resource balance non-firm power supply that may be available to utilities to meet needs. These non-firm sources include generation from uncommitted Northwest independent power producers (IPPs), imports from power plants located outside the region, uncommitted hydro generation owned by Northwest utilities, and hydro generation likely available when water supply is greater than the assumed critical levels. Power from these resources may be available to the Northwest from the market, during high need hours, or it may have been already sold to a higher bidder outside the Northwest.

Non-firm imports depend on several factors including availability of out-of-region resources, availability of transmission, and market friction. The trend of large thermal resource retirements in the Western Interconnection could impact power available for import into the Northwest in the coming years. Looking at hydropower, the *Forecast* assumes low water (8%) during peak hours for the monthly peak calculations. Most months the water supply for the hydro system is not at critical levels. During a median water month, the region will have more water available for energy and peak needs.

Climate Change

More utilities and organizations are incorporating the impacts of a changing climate into their long-range planning. Two areas where climate change may impact utility planning is the influence of temperatures on loads and water supply for hydrogeneration. As more utilities account for changing temperature trends in their forecasting models the impact on utility loads becomes incorporated into the *Northwest Regional Forecast*. Increasing temperatures in the summer can result in higher summer load (due to air conditioning, for example) and moderately warmer temperatures in the winter can reduce winter load (reduced need for heating loads), on average across the region. The differences in geography for utilities across the Northwest means individual utilities can have varying degrees of climate change effects.

The *2024 Forecast* does not explicitly include the impact of climate change on hydroelectric generation. It is only included to the extent that it is included in a hydro-project owner/sponsor's submittal of its peak capability for the project. The report's hydroelectric data for the bulk of the hydro data rely on the historical river flows.

Table 11. Utilities Included in the Northwest Regional Forecast

Albion, City of
Alder Mutual
Ashland, City of
Asotin County PUD #1
Avista Corp.
Bandon, City of
Benton PUD
Benton REA
Big Bend Electric Co-op
Blachly-Lane Electric Cooperative
Blaine, City of
Bonners Ferry, City of
Bonneville Power Administration
Burley, City of
Canby Utility
Cascade Locks, City of
Central Electric
Central Lincoln PUD
Centralia, City of
Chelan County PUD
Cheney, City of
Chewelah, City of
City of Port Angeles
Clallam County PUD #1
Clark Public Utilities
Clatskanie PUD
Clearwater Power Company
Columbia Basin Elec. Co-op
Columbia Power Co-op
Columbia REA
Columbia River PUD
Consolidated Irrigation Dist. #19
Consumers Power Inc.
Coos-Curry Electric Cooperative
Coulee Dam, City of
Cowlitz County PUD
Declo, City of
Douglas County PUD
Douglas Electric Cooperative
Drain, City of
East End Mutual Electric
Eatonville, City of
Ellensburg, City of
Elmhurst Mutual P & L
Emerald PUD
Energy Northwest
Eugene Water & Electric Board
Fall River Rural Electric Cooperative
Farmers Electric Co-op
Ferry County PUD #1
Fircrest, Town of
Flathead Electric Cooperative
Forest Grove Light & Power
Franklin County PUD
Glacier Electric
Grant County PUD
Grays Harbor PUD
Harney Electric
Hermiston, City of
Heyburn, City of
Hood River Electric
Idaho County L & P
Idaho Falls Power
Idaho Power
Inland Power & Light
Kittitas County PUD
Klickitat County PUD
Kootenai Electric Co-op
Lakeview L & P (WA)
Lane Electric Cooperative
Lewis County PUD
Lincoln Electric Cooperative
Lost River Electric Cooperative
Lower Valley Energy
Mason County PUD #1
Mason County PUD #3
McCleary, City of
McMinnville Water & Light
Midstate Electric Co-op
Milton, Town of
Milton-Freewater, City of
Minidoka, City of
Missoula Electric Co-op
Modern Electric Co-op
Monmouth, City of
Nespelem Valley Elec. Co-op
Northern Lights Inc.
Northern Wasco Co. PUD
NorthWestern Energy
Ohop Mutual Light Company
Okanogan Co. Electric Cooperative
Okanogan County PUD #1
Orcas Power & Light
Oregon Trail Co-op
Pacific County PUD #2
PacifiCorp
Parkland Light & Water
Pend Oreille County PUD
Peninsula Light Company
Plummer, City of
PNGC Power
Port of Seattle – SEATAC
Portland General Electric
Puget Sound Energy
Raft River Rural Electric
Ravalli Co. Electric Co-op
Richland, City of
Riverside Electric Co-op
Rupert, City of
Salem Electric Co-op
Salmon River Electric Cooperative
Seattle City Light
Skamania County PUD
Snohomish County PUD
Soda Springs, City of
Southside Electric Lines
Springfield Utility Board
Steilacoom, Town of
Sumas, City of
Surprise Valley Elec. Co-op
Tacoma Power
Tanner Electric Co-op
Tillamook PUD
Troy, City of
Umatilla Electric Cooperative
Umpqua Indian Utility Co-op
United Electric Cooperative
US Corps of Engineers
US Bureau of Reclamation
Vera Water & Power
Vigilante Electric Co-op
Wahkiakum County PUD #1
Wasco Electric Co-op
Weiser, City of
Wells Rural Electric Co.
West Oregon Electric Cooperative
Whatcom County PUD
Yakama Power

Definitions

Annual Energy

Energy value in megawatts that represents the average output over the period of one year. Expressed in average megawatts.

Average Megawatts

(aMW) Unit of energy for either load or generation that is the ratio of energy (in megawatt-hours) expected to be consumed or generated during a period of time to the number of hours in the period.

Batteries

Batteries are some of the newest technologies being added to the regional picture. See storage definition.

Biomass

Any organic matter which is available on a renewable basis, including forest residues, agricultural crops and waste, wood and wood wastes, animal wastes, livestock operation residue, aquatic plants, and municipal wastes.

Canadian Entitlement

Canada is entitled to one-half the downstream power benefits resulting from Canadian storage as defined by the Columbia River Treaty. Canadian entitlement returns estimated by Bonneville Power Administration.

Coal Resource

This category of generating resources includes the region's coal-fired plants.

Cogeneration

Cogeneration is the technology of producing electric energy and other forms of useful energy (thermal or mechanical) for industrial and commercial heating or cooling purposes through sequential use of an energy source.

Combustion Turbines

These are plants with combined-cycle or simple-cycle natural gas-fired combustion turbine technology for producing electricity.

Committed Resources

These projects are under construction and/or committed resources and supply confirmed to meet Northwest load, but not delivering power as of December 31, 2023.

Conservation

Any reduction in electrical power consumption as a result of increases in the efficiency of energy use, production, or distribution. For the purposes of this report used synonymously with energy efficiency.

Demand Response

Control of load through customer/utility agreements that result in a temporary change in consumers' use of electricity.

Demand-side Management

Peak and energy savings from conservation/energy efficiency measures, distribution efficiency, market transformation, demand response, fuel conversion, fuel switching, energy storage and other efforts that that serve to reduce electricity demand.

Dispatchable Resource

A term referring to controllable generating resources that are able to be dispatched for a specific time and need.

Direct Service Industries (DSI)

Large electricity-intensive industries such as aluminum smelters and metals-reduction plants that purchase power directly from the Bonneville Power Administration for their own use. Very few of these customers exist in the region today.

Distribution Efficiency

Infrastructure upgrades to utilities' transmission and distribution systems that save energy by minimizing losses.

Emerging Technologies

A term used to describe future resource technologies such as advanced nuclear, offshore wind, renewable hydrogen, and long-duration storage.

Encroachment

A term used to describe a situation where the operation of a hydroelectric project causes an increase in the level of the tailwater of the project that is directly upstream.

Energy Efficiency

Any reduction in electrical power consumption as a result of increases in the efficiency of energy use, production, or distribution. For the purposes of this report used synonymously with conservation.

Energy Load

The demand for power averaged over a specified period of time.

Energy Storage

Technologies for storing energy in a form that is convenient for use at a later time when a specific energy demand is greater.

Exports

Firm interchange arrangements where power flows from regional utilities to utilities outside the region or to non-specific, third-party purchasers within the region.

Federal System (BPA)

The federal system is a combination of BPA's customer loads and contractual obligations, and resources from which BPA acquires the power it sells. The resources include plants operated by the U.S. Army Corps of Engineers (COE), U.S. Bureau of Reclamation (USBR) and Energy Northwest. BPA markets the thermal generation from Columbia Generating Station, operated by Energy Northwest.

Federal Columbia River Power System (FCRPS)

Thirty federal hydroelectric projects constructed and operated by the Corps of Engineers and the Bureau of Reclamation, and the Bonneville Power Administration transmission facilities.

Firm Energy

Electric energy intended to have assured availability to customers over a defined period.

Firm Load

The sum of the estimated firm loads of private utility and public agency systems, federal agencies and BPA industrial customers.

Firm Losses

Losses incurred on the transmission system of the Northwest region.

Fuel Conversion

Consumers' efforts to make a permanent change from electricity to natural-gas or other fuel source to meet a specific energy need, such as heating.

Fuel Switching

Consumers' efforts to make a temporary change from electricity to another fuel source to meet a specific energy need.

Historical Streamflow Record

A database of unregulated streamflows for 90 years (August 1928 to July 2018). Data is modified to take into account adjustments due to irrigation depletions, evaporations, etc. for the particular operating year being studied.

Hydro Maintenance

The amount of energy lost due to the estimated maintenance required during the critical period. Peak hydro maintenance is included in the peak planning margin calculations.

Hydro Regulation

A study that utilizes a computer model to simulate the operation of the Pacific Northwest hydroelectric power system using the historical streamflows, monthly loads, thermal and other non-hydro resources, and other hydroelectric plant data for each project.

Imports

Firm interchange arrangements where power flows to regional utilities from utilities outside the region or third-party developer/owners of generation within the region.

Independent Power Producers (IPPs)

Non-utility entities owning generation that may be contracted (fully or partially) to meet regional load.

Intermittent Resource (a.k.a. Variable Energy Resource)

An electric generating source with output controlled by the natural variability of the energy resource rather than dispatched based on system requirements. Intermittent output usually results from the direct, non-stored conversion of naturally occurring energy fluxes such as solar and wind energy.

Investor-Owned Utility (IOU)

A privately owned utility organized under state law as a corporation to provide electric power service and earn a profit for its stockholders.

Market Transformation

A strategic process of intervening in a market to accelerate the adoption of cost-effective energy efficiency.

Megawatt (MW)

A unit of electrical power equal to 1 million watts or 1,000 kilowatts.

Nameplate Capacity

A measure of the approximate generating capability of a project or unit as designated by the manufacturer.

Natural Gas-Fired Resources

This category of resources includes the region's natural gas-fired plants, mostly single-cycle and combined-cycle combustion turbines. It may include projects that are considered cogeneration plants.

Non-Firm Resources

Electric energy acquired through short term purchases of resources not committed as firm resources. This includes generation from hydropower in better than critical water conditions, independent power producers and imports from outside the region.

Non-Utility Generation

Facilities that generate power whose ownership by a sponsoring utility is 50 percent or less. These include PURPA-qualified facilities (QFs) and non-qualified facilities of independent power producers.

Nuclear Resources

The region's only nuclear plant, the Columbia Generating Station, is included in this category.

Operating Year

Twelve-month period beginning on August 1 of any year and ending on July 31 of the following year. For example, operating year 2024 is August 1, 2024 through July 31, 2025.

Other Publics (BPA)

Refers to the smaller, non-generating public utility customers whose load requirements are estimated and served by Bonneville Power Administration as referred to in Table 10.

Peak Load

In this report the peak load is defined as one-hour maximum demand for power.

Planned Future Resources

These resources include specific resources and/or blocks of generic resources identified in utilities' most current integrated resource plans and planning studies. These projects are not yet under construction, are not part of the regional analysis, and are in some ways speculative.

Planning Margin

A component of regional requirements that is included in the peak needs assessment to account for various planning uncertainties. In the 2018 *Forecast* the planning margin changed to a flat 16% of the regional load for each year of the study. Earlier reports included a growing planning margin that started at 12% of load, increasing 1% per year until it reached 20%.

Private Utilities

Same as investor-owned utilities.

Publicly-Owned Utilities

One of several types of not-for-profit utilities created by a group of voters and can be a municipal utility, a public utility district, or an electric cooperative.

PURPA

Public Utility Regulatory Policies Act of 1978. The first federal legislation requiring utilities to buy power from qualifying independent power producers.

Renewables - Other

A category of resources that includes projects that produce power from such fuel sources as geothermal, biomass (includes wood, municipal solid-waste facilities), and pilot level projects including tidal and wave energy.

Requirements

Include for each year, a utility's projected loads, exports, and contracts out. Peak requirements also include the planning margin.

Small Thermal & Miscellaneous Resources

This category of resources includes small thermal generating resources such as diesel generators used to meet peak and/or emergency loads.

Solar Resources

Resources that produce power from solar exposure. This includes utility scale solar photovoltaic systems but does not include distributed solar generation.

Storage

Storage resources (i.e., batteries, pumped hydro, liquid air) store energy for release at a later time. They can help shift energy from low value to high value hours. Due to efficiency losses, they are a net consumer of energy. They are usually defined by their maximum discharge rate in MW, and their total storage capacity in MWh.

Thermal Resources

Resources that burn coal, natural gas, oil, diesel or use nuclear fission to create heat which is converted into electricity.

Variable Energy Resource (a.k.a. Intermittent Resource)

An electric generating source with output controlled by the natural variability of the energy resource rather than dispatched based on system requirements. Intermittent output usually results from the direct, non-stored conversion of naturally occurring energy fluxes such as solar and wind energy.

Wind Resources

This category of resources includes the region's utility-scale wind powered projects.

Western Energy Imbalance Market (WEIM)

A real-time energy market launched in 2014, operated by the California Independent System Operator.

Western Resource Adequacy Program (WRAP)

A regional reliability and compliance program in the West. It delivers a region-wide approach for assessing and addressing resource adequacy.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Reply Testimony of Cecelia J. Tanaka

EQUITY
EXHIBIT 2300

June 4, 2024

EXHIBIT 2300 - REPLY TESTIMONY – EQUITY

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I. INTRODUCTION

Q. Are you the same Cecelia Tanaka who presented Direct Testimony in this proceeding on behalf of Northwest Natural Gas Company dba NW Natural ("NW Natural" or the "Company")?

A. Yes, I presented NW Natural/200, Tanaka.

Q. What is the purpose of your Reply Testimony?

A. In my Reply Testimony, I respond to the Opening Testimony of Public Utility Commission of Oregon Staff ("Staff"), the Oregon Citizens' Utility Board ("CUB"), and the Coalition regarding the Company's bill discount program, the Low-Income Needs Assessment ("LINA"), and Oregon Low Income Energy Efficiency Program ("OLIEE"). I also address other issues raised in Staff and intervenor Opening Testimony that directly or indirectly relate to energy justice.

Q. Please provide a summary of your testimony.

A. NW Natural requests the Commission approve its bill discount program as presented in my Direct Testimony, as the program updates have been thoughtfully designed to provide deeper discounts and more meaningful energy burden relief for NW Natural's low-income customers. Staff and the Coalition criticize the bill discount program for not providing deep enough discounts for low-income customers, though at the same time, Staff also expresses concern about program costs and the impact of these discounts on customer rates. In my Reply Testimony, I explain how the Company has structured the bill discount program to provide relief within each of discount tiers, provide analysis of the energy burden mitigation offered by the current program in comparison with the proposed program, and

provide data illustrating the impact of the bill discount program on the other customer classes who will collectively pay for the program and explain the Company's position on a fixed per-bill charge for cost recovery. I also respond to Staff and the Coalition's comparison of NW Natural's bill discount levels with those of Cascade and Avista, and explain that unlike those utilities, NW Natural's bill discount program is part of a suite of offerings, including the Oregon Low-Income Gas Assistance Program ("OLGA") and the Gas Assistance Program ("GAP"), that also provide relief to energy burdened customers.

I also respond to the Coalition's testimony addressing the Company's LINA and describe the Company's plans to complete a new Energy Burden Assessment ("EBA") by fall 2024 that is informed by the lessons learned from the Company's first LINA.

In addition, my Reply Testimony discusses the OLIEE program, and responds to Staff and the Coalition's assertions that the Company should increase enrollment in the program and corrects the Coalition's misunderstandings as to OLIEE funding. I also address the Coalition's recommendations that funds be disbursed for electrification efforts and explain that this is an inappropriate use of funds collected from NW Natural's customers, particularly so when there is an entirely separate pool of federal funding available to support projects such as electric heat pump installations.

I also respond to the Coalition's arguments that the Company is not doing enough to advertise the availability of its discount programs and describe the

targeted outreach the Company is undertaking to ensure that eligible customers are aware of the programs and how to apply.

Finally, I respond to Staff's comments on the Company's Community Equity Advisory Group ("CEAG") and reiterate how the CEAG is guiding equitable collaboration on energy justice issues.

II. BILL DISCOUNT PROGRAM

Q. Please describe Staff's and intervenors' Opening Testimony discussing the bill discount program.

A. Staff appreciates the Company's work to respond to stakeholders' concerns in updating the bill discount program to adjust to customer needs. However, Staff also raises a number of concerns with the structure of the bill discount program, seeking changes to increase the discount levels and recalculations of the tiers targeting the lowest income levels instead of the midpoint.[1] Staff is concerned that using the midpoint of the tier to structure discounts does not capture enough of the energy burden for customers in that tier.[2] Staff also seeks to have the Company increase enrollment of the bill discount program[3] and discusses a desire to understand which customer classes will bear the burden of funding the cost recovery for this program through Schedule 335.[4]

[1] Staff/1200, Lockwood/24-26.

[2] Staff/300, Scala/9; Staff/1200, Lockwood/25-26.

[3] Staff/300, Scala/22.

[4] Staff/300, Scala/10-12; Staff/1200, Lockwood/26.

The Coalition testifies that it seeks to improve the program by deepening discounts, adding offerings to the bill discount program, and modifying the enrollment process.[5] Specifically, the Coalition suggests that NW Natural increase discounts for Tier 0, Tier 1, and Tier 2 customers, pointing to Cascade and Avista bill discount programs as examples.[6] The Coalition also testifies that the bill discount program should include an arrearage forgiveness element for Tier 0 customers that is "on par with its peer utilities."[7] The Coalition additionally recommends that the Commission "encourage" the Company to use the self-sufficiency standard ("SSS") in conjunction with the state median income ("SMI") index, require the Company to identify low-income customers that can benefit from the bill discount program in its next EBA, and ensure that the Company enroll at least 75 percent of bill assistance eligible households in the Test Year.[8] The Coalition also alleges the Company of failing to advertise its bill discount program, recommending the Commission require the Company to prepare a "communication strategy" to increase customer recognition of the bill discount program.[9] The Coalition also recommends the Commission require the Company to eliminate post-enrollment verifications, prohibit the Company from suspending

[5] Coalition/300, Fain-Segovia Rodriguez-Daryanani/5.

[6] Coalition/300, Fain-Segovia Rodriguez-Daryanani/21-22.

[7] Coalition/300, Fain-Segovia Rodriguez-Daryanani/23-24, 30.

[8] Coalition/300, Fain-Segovia Rodriguez-Daryanani/30.

[9] Coalition/300, Fain-Segovia Rodriguez-Daryanani/24-25, 31.

bill discounts pending income verification, and stop the Company from making customers "re-apply" for bill discounts after verifying income.[10]

Although CUB does not testify directly about the structure of the bill discount program, it does suggest that the Commission require the Company to provide a report on how it is mitigating rate shock in part through the bill discount program.[11]

A. Bill Discount Program – Program Design

Q. Please provide a brief overview of the Company's proposed changes to the bill discount program that were proposed in this case.

A. In my Direct Testimony,[12] I describe the Company's proposal to improve upon the original design of the approved bill discount program by increasing the bill discount percentages for Tiers 0 and 1 by using the midpoint of incomes within tiers to evaluate and target an appropriate assumed energy burden. Specifically, the Company proposed to increase the deepest discount available to the lowest income customers, Tier 0, from 40 percent to 80 percent.[13] The Company also proposed to increase available discounts for the second-lowest income tier, Tier 1, from 25 percent to 40 percent.[14] These changes are intended to target and reduce the program participants' gas usage-related energy burden to three percent of income or less.[15]

[10] Coalition/300, Fain-Segovia Rodriguez-Daryanani/31.

[11] NW Natural/200, Tanaka/24.

[12] NW Natural/200, Tanaka/22.

[13] NW Natural/200, Tanaka/23-24, Tables 2 and 3.

[14] NW Natural/200, Tanaka/23-24, Tables 2 and 3.

[15] NW Natural/200, Tanaka/24.

Q. Do Staff and the Coalition support the customer tiers the Company proposed in the bill discount program?

A. No. Staff testifies that it is unsure whether the new proposed tiers ranging from 25 – 80 percent discounts are deep enough discounts, potentially failing to serve the customers with the highest energy burden.[16] Staff also questions the Company's decision to target the midpoint of a tier when calculating the discount needed to reduce that tier's energy burden and whether there is a normal income distribution of participants within the tier.[17] Staff suggests that the bill discount's impact on household energy burden may be overestimated if actual incomes fall towards the lower end of the tier (rather than the midpoint of the tier) and/or if actual household energy usage is higher than what the data show.[18]

For these reasons, Staff and the Coalition suggest that the discounts in the Company's proposed bill discount program do not go far enough to protect the lowest-income customers.[19]

Q. Why did the Company target the midpoint of the income tiers for the bill discount program?

A. This approach is an improvement upon the original design of the bill discount program by providing additional coverage for the members of the tier than the prior bill discount program, which used the maximum income of a tier to estimate energy

[16] Staff/300, Scala/9.

[17] Staff/300, Scala/7; Staff/1200, Lockwood/25.

[18] Staff/300, Scala/7-9; Staff/1200, Lockwood/25.

[19] Coalition/300, Fain-Segovia Rodriguez-Daryanani/4-5.

burden. Using the midpoint estimation method is a common statistical approach used to reduce the impact of extreme outliers; by using the midpoint of an income tier to assign meaningful bill discount levels and estimate energy burden, we can get values that are more representative of the average customer within each income tier. Further, as detailed in my Direct Testimony,[20] when estimating the impact of discounts on energy burden, using the midpoint ensures that the discounts are calibrated to the needs of the "average" household rather than the highest or lowest incomes, which aligns better with our shared goals of delivering resources where they are needed most, as well as providing discounts that can have meaningful impacts on household finances and energy burden.

Absent more granular data about the distribution of customer incomes within the bill discount tiers, which we hope to obtain through the EBA[21] that is currently underway, use of the midpoint of income within a tier is a reasonable way to improve energy burden relief in comparison with the existing design that uses the maximum income within a tier. Once more granular data are known, design of the tiers can be better evaluated for further changes.

[20] NW Natural/200, Tanaka/22-23.

[21] Please note that in NW Natural/200, Tanaka, we used the term Low-Income Needs Assessment ("LINA") to refer to the study that provides insight into customer and community characteristics, eligible populations, participation in current Energy Assistance offerings, and barriers and opportunities for current or future Energy Assistance offerings. Going forward, we will be referring to this study with the preferred term Energy Burden Assessment ("EBA"). During this terminology transition, the terms LINA and EBA may be used interchangeably.

Q. How did the Company arrive at the proposed tier discounts?

A. As discussed in my Direct Testimony,[22] the income tiers were designed in a collaborative manner among the Company, Staff, and low-income advocates through a series of workshops and comments in docket ADV 1390. During the time of the ADV 1390 docket, no stakeholder raised an issue regarding the use of max income to design the discount tiers. To create the current proposal in this case, NW Natural reviewed the discount tiers of the bill discount program using experience and data gained since the launch of the program and guidance from the LINA to arrive at the proposed changes intended to better reduce the energy burden of those customers most in need.

Q. Please explain the Company's evaluation of whether new income tiers are likely to benefit low-income customers.

A. The increase in bill discounts will benefit low-income customers. The Company updated the income tiers to capture more customers within the income tier and target their energy burden to reduce it to below three percent.[23] As provided in my Direct Testimony,[24] the tables below provide a comparison of program discount impacts using the max-point income (current approach) versus the midpoint (new approach).

[22] NW Natural/200, Tanaka/22.

[23] NW Natural/200, Tanaka/22-23.

[24] NW Natural/200, Tanaka/22-23.

Table 1- Current Bill Discount Tiers

Bill Discount Program Impacts, Assuming Household of 4:	SMI 60% Tier 3 - 15%	SMI 45% Tier 2 - 20%	SMI 30% Tier 1 - 25%	SMI 15% Tier 0 -40%
Income max of tier	$56,430	$42,323	$28,215	$14,108
Average annual bill	$758.35	$758.35	$758.35	$758.35
Bill as % income before discount	1.3%	1.8%	2.7%	5.4%
Bill discount	$113.75	$151.67	$189.59	$303.34
Bill after discount	$644.60	$606.68	$568.76	$455.01
Bill as % income after discount	1.1%	1.4%	2.0%	3.2%

Note that this table reflects the rates and income eligibility tables that were assumed at the time of the design of the bill discount program in 2022.

Table 2 - Proposed Bill Discount Tiers

Bill Discount Program Impacts, Assuming Household of 4:	SMI 60% Tier 3 - 15%	SMI 45% Tier 2 - 20%	SMI 30% Tier 1 - 40%	SMI 15% Tier 0 - 80%
Income mid-point of tier	$56,246	$40,176	$24,106	$8,035
Average annual bill	$1,124.87	$1,124.87	$1,124.87	$1,124.87
Bill as % income before discount	2.0%	2.8%	4.7%	14.0%
Bill discount	$168.73	$224.97	$449.95	$899.90
Bill after discount	$956.14	$899.90	$674.92	$224.97
Bill as % income after discount	1.7%	2.2%	2.8%	2.8%

Note that this table reflects the rates for Residential Schedule 2 proposed in this case and income eligibility tables for 2023-2024.

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Q. Staff testifies it is concerned that the Company's targeting the midpoint of the income tier may underestimate the amount of discount needed for the average income customer in any given tier.[25] How does the Company respond?

A. The midpoint of an income tier means that half of all households within that tier earn more than, and half earn less than, the midpoint. Using Staff's own logic, targeting the midpoint of the income tier could just as easily *overestimate* the amount of discount needed within a given tier. Using the midpoint to estimate energy burden provides a representative value that lies between the lower and upper bounds of any income tier—effectively excluding extreme outliers at both ends of the distribution. The approach that NW Natural is taking results in a more balanced and representative estimate of energy burden for the incomes that fall within each tier.

Q. How does the Company respond to Staff's concern that the bill discount program will be less effective for the highest energy burdened and lowest income households?[26]

A. It is true that there is a range of effectiveness inherent when using a tiered design. However, NW Natural's proposal to increase the bill discount for Tiers 1 and 0 are improvements in the existing effectiveness of the bill discount program on the highest energy burdened and lowest income households. This can be illustrated

[25] Staff/1200, Lockwood/25.

[26] Staff/300, Scala/7.

by expanding Table 2 from Staff's own testimony to include a comparison of the Company's proposal and the existing design.[27] Table 3 below includes the first four columns of Staff's Table 2, to which two additional columns are added to illustrate the energy burden impacts under the current Tier 0 design. In addition, the two added columns include shading consistent with Staff's shading of after-discount energy burdens of 4.8 percent and higher. As demonstrated in Table 3 below, relief for energy burdened customers is greatly enhanced under the Company's proposal.

Table 3 – Tier 0 Impacts on Estimated Energy Burden

		Proposed Tier 0 Design Energy Burden		Current Tier 0 Design Energy Burden	
% SMI	Income	Before Discount	After Discount	Before Discount	After Discount
15%	$14,061.50	8.0%	1.6%	8.0%	4.8%
14%	$13,124.07	8.6%	1.7%	8.6%	5.1%
13%	$12,186.63	9.2%	1.8%	9.2%	5.5%
12%	$11,249.20	10.0%	2.0%	10.0%	6.0%
11%	$10,311.77	10.9%	2.2%	10.9%	6.5%
10%	$9,374.33	12.0%	2.4%	12.0%	7.2%
9%	$8,436.90	13.3%	2.7%	13.3%	8.0%
8%	$7,499.47	15.0%	3.0%	15.0%	9.0%
7%	$6,562.03	17.1%	3.4%	17.1%	10.3%
6%	$5,624.60	20.0%	4.0%	20.0%	12.0%
5%	$4,687.17	24.0%	4.8%	24.0%	14.4%
4%	$3,749.73	30.0%	6.0%	30.0%	18.0%
3%	$2,812.30	40.0%	8.0%	40.0%	24.0%
2%	$1,874.87	60.0%	12.0%	60.0%	36.0%
1%	$937.43	120.0%	24.0%	120.0%	72.0%

[27] Staff/300, Scala/8 – Table 2.

For those bill discount participants whose income falls under the midpoint of the SMI tier, NW Natural and federal energy assistance programs described in my Direct Testimony[28] can help fill those gaps. The level of relief that these income-based programs have is displayed in Table 4 (which is an extension of Table 1 from my Direct Testimony). Note that over the last five program years, the average Low Income Home Energy Assistance Program ("LIHEAP") grant was $345 and the average OLGA grant was $415. These average grant levels translate into an effective discount of 30.7 percent and 36.9 percent, respectively, on an average annual bill. In this way – by participating in LIHEAP and/or OLGA and the bill discount program – customers at the lower ends of the income tiers can secure a meaningful reduction of their energy burden.

Table 4 – Impact of Income-Based Assistance Programs

Energy Assistance Program	Average Benefit last 5 program years	Total Benefits 2022-23 program year	Customers served 2022-23 program year
LIHEAP	$345	$1,130,831	2,504
OLGA	$415	$3,688,238	7,553
GAP (OR & WA #s)	$116	$195,588	1,525
OLIEE	N/A	$1,836,123	175

[28] NW Natural/200, Tanaka/15.

Q. The Coalition points to Cascade and Avista discount programs to state NW Natural should increase its Tier 0 discounts over 80 percent.[29] Specifically, the Coalition suggests that the Company increase discount rates for Tiers 0-2 customers to 90 percent, 70 percent, and 50 percent respectively.[30] How do you respond?

A. Generally, utilities have autonomy in designing, refining and delivering programs best suited to their customers' needs and own capabilities to safely and affordably meet those needs. In 2022, pursuant to direction provided in docket UM 2211, several utilities brought forward bill discount programs. These programs were designed specifically for each utility's customer base and capabilities, and thus each utility's program differed from the other utilities' programs. As was frequently pointed out during the approval process for NW Natural's bill discount program in ADV 1390, NW Natural's bill discount program was proposed as an incremental, additional assistance program to complement its existing income-based assistance programs OLGA, GAP and OLIEE. This differed from the proposals made by Avista and Cascade, which both proposed a comprehensive reorganization of their low-income bill assistance program into a bill discount program along with other features to **replace** their existing low-income bill assistance grant programs. While I have no direct knowledge of the choices those companies made when designing their bill discount programs, it stands to reason

[29] Coalition/300, Fain-Segovia Rodriguez-Daryanani/22.

[30] Coalition/300, Fain-Segovia Rodriguez-Daryanani/20.

that discontinuing a bill assistance program would result in higher bill discount percentages in the design of the bill discount program. As was discussed throughout the workshops and comments in the ADV 1390 process, any comparison of NW Natural's bill discount program to these programs must take these significant differences into consideration. Table 5 below provides a comparison of the program offerings from the three Oregon gas local distribution companies ("LDCs") and includes the impact of NW Natural's OLGA program.[31] As can be seen in the table, when the impact of NW Natural's bill assistance grant program is included in the comparison, NW Natural's programs offer comparable, if not higher, levels of relief in comparison with the other utilities at every income tier.

Table 5 – Comparison of Utility Programs' Level of Relief

Max income Tier levels	NW Natural Bill Discount	NW Natural OLGA impact	NW Natural Total	Avista Bill Discount	Cascade Bill Discount
60% SMI	15%	37%	52%	15%	15%
45% SMI	20%	37%	57%	15%	45%
40% SMI	20%	37%	57%	25%	45%
30% SMI	40%	37%	77%	25%	70%
20% SMI	40%	37%	77%	60%	70%
15% SMI	80%	37%	117%	60%	95%
5% SMI	80%	37%	117%	90%	95%

[31] Note that customers can, and do, participate in both OLGA and LIHEAP; however, for simplicity this table takes only OLGA into account.

Q. The Coalition suggests that the bill discount program is not complete without an arrearage forgiveness component available to Tier 0 customers that is "on par with its peer utilities."[32] Why did the Company not include arrearage forgiveness as a component of the bill discount program?

A. As discussed above, the bill discount programs implemented by the Oregon LDCs are unique to each utility's capabilities and customer needs. Avista and Cascade both proposed a comprehensive reorganization of their low-income bill assistance program into a bill discount program along with other features such as an arrearage management program to **replace** their existing low-income bill assistance grant programs; they no longer have a company-supported grant-based bill assistance program. NW Natural's bill discount program was added as an **incremental** program to complement its other low-income offerings, which include our grant-based bill assistance program OLGA. As mentioned in my Direct Testimony,[33] NW Natural will learn more about the needs of customers through the upcoming EBA that is currently underway. Through this process we may learn more about the efficacy of other assistance programs that would work for our customers.

NW Natural notes that as part of our last LINA, customers were asked to rank three types of potential Energy Assistance programs in order of preference: 1) A discount program that provides a percentage discount on their monthly NW

[32] Coalition/300, Fain-Segovia Rodriguez-Daryanani/30.

[33] NW Natural/200, Tanaka/12-13.

Natural bill; 2) A forgiveness program that eliminates or reduces their prior unpaid bills to NW Natural; and 3) A time payment arrangement program where they negotiate a contract with NW Natural to pay a fixed amount for natural gas service over a specific period of time (one to two years). Customers overwhelmingly chose a discount program, and then time-payment arrangements over a forgiveness program.

Q. Are there practical concerns with further increasing discount levels or adding an arrearage forgiveness element to the bill discount program?

A. Yes. As an initial matter, proposing major changes to the bill discount program or adding additional assistance programs would be premature due to the EBA that is currently underway and the significant policy exploration taking place in the UM 2211 docket. As discussed in my Direct Testimony,[34] we evaluated the effectiveness and reach of the current tools NW Natural offers that help to mitigate energy burden as part of our preparation of this general rate case to determine if current tools were adequate to help mitigate the impact of any resulting rate changes. As illustrated in my Direct Testimony,[35] this analysis shows that NW Natural's current energy burden mitigation tools such as the bill discount program, OLGA, LIHEAP and GAP remain effective for customers. Even so, NW Natural looks forward to having the results of the current EBA, as well as policy guidance from the UM 2211 docket, to further enhance its offering of energy burden

[34] NW Natural/200, Tanaka/29.

[35] NW Natural/200, Tanaka/29-32.

mitigation tools as we look ahead. The ongoing balancing of cost and benefit is always under consideration. NW Natural is confident in its current allocation of resources and priorities based on the information we have; that said, this may change with new information available only after the completion of the 2024 EBA.

Q. The Coalition also recommends that the Commission require the Company to increase enrollment in the bill program to reach 75 percent of eligible households significantly throughout the next year.[36] Before turning to the Coalition's specific recommendation, is the Company seeking to increase enrollment in the bill discount program?

A. Yes. The Company continues to increase enrollment in the bill discount program. We share this priority and are dedicating meaningful resources to this end. However, and as mentioned in my Direct Testimony,[37] since the number of eligible households within NW Natural's territory is unknown at this time, calculating enrollment percentages and milestones related to eligible customers is not possible yet. And while we can commit to increasing enrollment (both in numbers and percentage of all households), the Company raises concern over the recommendation of a 75 percent goal–this is far beyond most enrollment rates of other long-standing and well-known programs, including Medicare (51 percent),[38]

[36] Coalition/300, Fain-Segovia Rodriguez-Daryanani/30.

[37] NW Natural/200, Tanaka/12.

[38] Nany Ochieng, et al, *Medicare Advantage in 2023: Enrollment Update and Key Trends*, KFF (Aug. 9, 2023)(available at https://www.kff.org/medicare/issue-brief/medicare-advantage-in-2023-enrollment-update-and-key-trends/).

WIC (51 percent),[39] Temporary Assistance for Needy Families (20 percent),[40] Social Security Income (57 percent) [41] and LIHEAP (15 percent).[42]

Q. Is the Company preparing to use the next LINA or EBA to target these eligible households for enrollment?

A. Yes. The next EBA will develop reliable data on NW Natural's customers who qualify as energy-burdened and where they reside. This data or inventory will serve as a baseline for the energy assistance needs of NW Natural's residential customers—as well as identify underserved customers, assess existing income-based programs and develop concrete recommendations for modifications to improve access and participation. Findings will also help to identify gaps in program participation, uncover areas of unmet need and inform marketing and outreach strategies to reach customers who are not receiving any form of energy assistance for which they are eligible. As reported in my Direct Testimony,[43] one of the deliverables of NW Natural's first EBA was a basic energy burden analysis that included a mapping tool to identify energy burdened customers at the census block level. But it did not identify how many NW Natural customers resided in each

[39] Zoë Neuberger, Lauren Hall, and Linnea Sallack, *WIC's Critical Benefits Reach Only Half of Those Eligible*, CENTER ON BUDGET AND POLICY PRIORITIES (Feb. 21, 2024) (available at https://www.cbpp.org/research/food-assistance/wics-critical-benefits-reach-only-half-of-those-eligible).

[40] U.S. Dept. of Health and Human Servs., Office of the Assistant Secretary for Planning and Evaluation, *22nd Welfare Indicators and Risk Factors Report to Congress* (Apr. 28, 2023) (available at https://aspe.hhs.gov/reports/22nd-welfare-indicators-risk-factors-report-congress).

[41] *Id.*

[42] Nat. Energy & Util. Affordability Coalition, *Oregon LIHEAP FY2022 State Profile* (Jun. 30, 2023) (available at https://neuac.org/wp-content/uploads/2023/12/FY2022OregonProfile-508Compliant.pdf).

[43] NW Natural/200, Tanaka/12.

census block. The next EBA will take this analysis a step further and will uncover the pool of program-eligible customers specifically among NW Natural's customer base (as opposed to general statistics for residents in the service area).

Q. Turning now to the Coalition's specific recommendation, is its proposed 75 percent mandatory enrollment threshold realistic?

A. No. As discussed above, 75 percent far exceeds most enrollment rates of other long-standing and well-known programs.

Q. The Coalition also claims that according to NW Natural's own data, 75 percent of Oregonian respondents had not heard of the bill discount program.[44] Is this statement correct?

A. No. The Coalition makes this inference based on a misunderstanding of the LINA data and what was reported in my Direct Testimony. The LINA was conducted prior to the bill discount program so it is not reflective of the number of customers who are aware of the program since its launch. Specifically, the LINA stated,

> A quarter of respondents in both states are aware of NW Natural programs that can lower monthly bill payments or connect customers to free weatherization services, while only 23% of Oregon and 13% of Washington respondents had participated in a program in the past.

This LINA question was referring to assistance programs like OLGA and GAP. Despite the Coalition's using this statement to claim that the Company has failed to inform customers of the bill discount program, the Coalition ignores that the bill discount program did not exist at the time of this survey. The Coalition also ignores

[44] Coalition/300, Fain-Segovia Rodriguez-Daryanani/26.

language in my Direct Testimony[45] (that also has been supplied through other channels) that clearly details the robust outreach strategy the Company executed in raising awareness of and participation in the bill discount program. In fact, the Company's outreach efforts have been commended and well-received by a wide swath of constituents—including community-based organizations, customers, advisory groups, and regulatory bodies. Other important indicators of the strategy's innovative and creative qualities are that our peer utilities have modeled their own outreach efforts after ours and have called upon the expertise of Company staff to present on outreach recommendations.

Q. How does the Company respond to the Coalition's recommendation that it prepare a "communication strategy" to increase knowledge of the bill discount program?

A. The Company prepares multiple integrated communications planning documents to guide communications each year. The bill discount program is included in those plans.

Q. How can customers enroll in the bill discount program?

A. Customers can enroll in the bill discount program easily and quickly. The application takes a few minutes to complete, and discounts appear on the next bill. Several steps were taken to ease program access and streamline enrollment, including:

[45] NW Natural/200, Tanaka/17-21.

- Auto-enrolling customers who received energy assistance and weatherization services. Customers who received either of these resources in the two years preceding the program launch date (November 1, 2022) were automatically enrolled. Indeed, this practice is ongoing—any customer who receives these services is auto-enrolled.
- The application is simple and can be completed online, or filled in and emailed or printed and mailed. Financial documents are not required: self-reported figures on household size and annual income verify eligibility. There are no enrollment deadlines or enrollment windows; customers can apply over the phone, and as mentioned above, online or by US mail.

Q. The Coalition additionally suggests the Company adopt the "self-sufficiency standard" to define "low income" for purposes of the bill discount program participants.[46] How do you respond?

A. Household energy costs are not an individual consideration for the SSS defined in The Self-Sufficiency Standard for Oregon 2021 report[47] (the "Oregon Report") as a measure of income adequacy that is "based on the costs of basic needs for working families: housing, childcare, food, health care, transportation, and miscellaneous items, as well as the cost of taxes and the impact of tax credits." In fact, nowhere in the Oregon Report are energy or utility expenses mentioned. The

[46] Coalition/300, Fain-Segovia Rodriguez-Daryanani/13.

[47] Univ. of Wash. Center for Women's Welfare, *The Self Sufficiency Standard for Oregon 2021* (Sept. 2021) (available at oregon.gov/workforceboard/data-and-reports/Documents/The-Self-Sufficiency-Standard-For-Oregon-2021.pdf).

SSS may be a useful tool to evaluate employment and workforce development programs–as detailed by the authors of the Oregon Report–but it is not a relevant or sufficient replacement for the conventional poverty measure for the Company's bill discount program. The Company uses energy burden as a key indicator to gauge, analyze and evaluate the effectiveness of the bill discount program given the metric's hyperfocus on the costs of energy —the service NW Natural provides.

Additionally, there are assistance programs in place for Oregonians targeting housing, childcare, food, health care, transportation, and other needs. To the extent our customers may already be receiving this assistance, it is unclear how that assistance would be factored into bill discount levels and allocations.

A secondary factor in the Company's position is the reality that what makes the SSS so valuable (e.g., accounting for indicators beyond income and household size, like county, fair market housing costs, age of children, taxes, etc.) is also what makes it much harder to accurately calculate, utilize, and evaluate. The map on page 6 of the Oregon Report[48] provides one example of this trade-off.

Q. The Coalition suggests the Company eliminate income verification for the bill discount program.[49] How do you respond?

A. The Company is proud to offer a bill discount program that utilizes self-attestation for enrollment. As reported in the March 13, 2024 update workshop (attended by two of the Coalition's witnesses supporting Coalition/300, Fain-Segovia

[48] *Id.* at 6.

[49] Coalition/300, Fain-Segovia Rodriguez-Daryanani/29-30.

Rodriguez-Daryanani), and at the April 25, 2024 UG 490 Environmental Justice Issues workshop, NW Natural has not yet begun post-enrollment verification. Post-enrollment verification will be the process by which a sample of bill discount program participants who self-attested their income will be contacted to demonstrate the income eligibility they self-attested. In addition to ensuring that program participants are enrolled in the correct tier, it is envisioned that the verification will also provide a means for customers to connect to additional energy assistance services. Post-enrollment verification of a sample of self-attested participants is not a strategy to remove participants from the program. It is necessary for the continued support of customer-funded dollars being used for this purpose and to promote the integrity of the program.

Q. How does the Company respond to the suggestion of eliminating post-enrollment verification?

A. To be clear, the Company's position to conduct post-enrollment verification is not a strategy to shame, penalize or limit access—the Company is not seeking to remove customers from this meaningful resource that eases energy burden. Conducting income verification for a small pool of program participants safeguards program integrity, strengthens public trust and demonstrates prudent management of customer funds. Auditing everyone would be resource-intensive and burdensome. Focusing on a sample strikes a balance between rigor and efficiency. It minimizes administrative overhead while still achieving the desired level of scrutiny. The practice ensures accountability and signals to our customer base that NW Natural is a diligent steward of these funds and that funds are being

used for their intended purpose. Asking ratepayers to pay for a program that has a specific purpose without any oversight or income verification compromises the sustainability and support of the program.

It should also be noted that income verification is required for most other federal and state programs in which eligibility for benefits is based on income. One report from the US Government Accountability Office found that agencies administering six of the country's largest federal programs used over 30 data sources to verify income and assets.[50]

The Company also points to recommendations from the U.S. Department of Energy on post-enrollment verification for programs that rely on self-attestation for entry:

> When allowing households to self-attest their income status, programs should independently verify each household's self-attested income prior to delivering rebate funds. If over time the program identifies that most applicants are adequately and accurately representing their income, programs may reduce the rate of income verification checks over time.[51]

[50] U.S. Gov't Accountability Office, *Federal Low-Income Programs: Use of Data to Verify Eligibility Varies Among Selected Programs and Opportunities Exist to Promote Additional Use*, GAO-21-183 (Mar. 29 2021) (available at https://www.gao.gov/products/gao-21-183).

[51] U.S. Dept. of Energy, *Serving Low-Income Households with Home Energy Rebates: Streamline Income Eligibility Processing* (Mar. 2024) (available at https://www.energy.gov/scep/slsc/home-energy-rebates-program/serving-low-income-households-home-energy-rebates).

Q. The Coalition further recommends the Commission prohibit NW Natural from suspending bill discounts for households that cannot or do not verify their income because there are a number of reasons customers may not respond to the Company's various attempts to verify income.[52] How do you respond?

A. This recommendation is premature, as any details of the verification process have yet to be determined.

Q. The Coalition also asks the Commission to prohibit NW Natural from having customers "re-apply" for bill discounts if they have been removed from the program for failing to verify income and then are subsequently able to demonstrate eligibility.[53] Is it true that the Company requires customers to re-apply for discounts upon verifying their income?

A. No. The Coalition is incorrect. No customer has been removed from the bill discount program for failing to verify income.

Q. The Coalition argues that "concerns of fraud and dishonesty do not outweigh the risk of eliminating assistance" for households that do not respond to requests to verify income.[54] Do you agree?

A. No. The Company takes issue with the allegation of Coalition that the "basis for income verification" is to uncover cases of "fraud and dishonesty." This is untrue and misrepresents the Company's ethos. Income verification of a small sample of

[52] Coalition/300, Fain-Segovia Rodriguez-Daryanani/29-31.

[53] Coalition/300, Fain-Segovia Rodriguez-Daryanani/29-31.

[54] Coalition/300, Fain-Segovia Rodriguez-Daryanani/29.

program participants serves as a strategic approach to maintain program integrity and public confidence while signaling responsible use of customer dollars.

Q. The Coalition states that NW Natural "puts the onus on the customer to re-apply for the bill discount program after being found ineligible and subsequently verifying eligibility."[55] Is the Coalition correct?

A. No. There is no re-application requirement for participants with verified income eligibility. In this scenario, a customer would be automatically and immediately enrolled once eligibility was verified. There would not be an additional step to "re-apply."

Q. The Coalition is concerned that the bill discount program does not go far enough to alleviate energy burden and instead that it merely mitigates some of the rate increase the Company is seeking.[56] How do you respond?

A. Once again, the Company points to a clear calculation of how the bill discount program reduces the energy burden of eligible participants across all tiers to below the industry standard of affordability of 3 percent.[57]

[55] Coalition/300, Fain-Segovia Rodriguez-Daryanani/29.

[56] Coalition/300, Fain-Segovia Rodriguez-Daryanani/17.

[57] Table 2 - Proposed Bill Discount Tiers.

B. Bill Discount Program - Cost Recovery

Q. Please describe Staff's concerns regarding cost recovery associated with the Company's bill discount program.

A. Staff is concerned about impacts of the changes to the bill discount program on the customer classes that will bear the cost recovery.[58] In particular, Staff is "uncertain" about cost projections of proposed changes to the bill discount program and "specifically concerned with the potential increase in costs due to the increase[d] discounts offered in Tier 0 and Tier 1."[59] Staff indicates that cost recovery is unequal between customer classes, and that industrial customers have a lower Schedule 335 impact on average.[60] Staff recommends that the Commission reject the bill discount program until the Company presents a cost analysis and projected changes to Schedule 335.[61] Alternatively, Staff proposes that NW Natural should withdraw the bill discount program from the rate case and put it into its own docket so that these questions can be explored.[62]

Q. How does the Company respond to the request for a cost analysis of the impacts of the proposed bill discount program?

A. The Company appreciates the sensitivity toward all customer classes that will be impacted by the expansion of the bill discount program. As noted in my Direct

[58] Staff/300, Scala/6; Staff/1200, Lockwood/25-26.

[59] Staff/1200, Lockwood/27.

[60] Staff/300, Scala/12.

[61] Staff/1200, Lockwood/27-28.

[62] Staff/1200, Lockwood/27.

Testimony,[63] NW Natural's last LINA did not provide detailed income information about our customers that could help us identify an estimated number of our income-eligible customers. Our upcoming EBA, which is currently in flight, will identify an estimate of our income-eligible customers. As a result, any cost analysis completed before the EBA is completed will necessarily need to focus on cost impacts of assumed participation levels without being informed by the participation rate of eligible customers.

Q. Has the Company prepared additional analysis regarding bill discount program costs as part of your Reply Testimony?

A. Yes. To be responsive to the concerns raised in Staff's testimony, the following tables provide cost and rate impacts of NW Natural's proposal to increase the bill discount percentage for Tier 1 and Tier 0. The first table (Table 6) begins with the current level of funding included in rates today, as approved in docket ADV 1562, which is $7.9 million. Next, we have calculated the impact of the proposed increase in the bill discount percentages for Tier 1 and Tier 0 as if the change had been in place at the time of ADV 1562 – this resulted in a total of $11.1 million, which is an increase of $3.2 million. Lastly, we have calculated the impact on costs as the percentage of residential customers participating in the bill discount program increases in 1.5 percent increments (Table 7). Note that as reported in docket RG 102, NW Natural has 47,121 participants in the bill discount program through March 2024, which is about 7.17 percent of all residential customers.

[63] NW Natural/200, Tanaka/8-13.

Table 6 - Cost Impact of Increased Discount at Increased Participation Levels

	Cost	Number of Participants	% of Residential Customers
Costs of 2024 estimate in rates (ADV 1562) (excludes previous year true-up)	$7,930,984	41,391	6.5%
Estimated cost with increased discounts for Tier 1 and 0	$11,123,836	41,391	6.5%
Estimated cost with increased discounts for Tier 1 and 0 at 8% participation	$12,521,654	50,943	8.0%
Estimated cost with increased discounts for Tier 1 and 0 at 9.5% participation	$13,919,472	60,495	9.5%
Estimated cost with increased discounts for Tier 1 and 0 at 11.0% participation	$15,317,290	70,046	11.0%
Estimated cost with increased discounts for Tier 1 and 0 at 12.5% participation	$16,715,108	79,598	12.5%

Table 7 - Rate Comparison of Increased Discount at Increased Participation Levels

	RS 2 Charge per Bill	RS 3 Charge per Bill	RS 27 Charge per Bill	RS 31 Charge per Bill	RS 32 Charge per Bill
Current costs in rates (ADV 1562)	$0.94	$3.24	$0.61	$25.90	$62.77
Estimated cost with increased discounts for Tier 1 and 0	$1.23	$4.26	$0.80	$34.03	$82.46
Estimated cost with increased discounts for Tier 1 and 0 at 8% participation	$1.36	$4.70	$0.89	$37.59	$91.08
Estimated cost with increased discounts for Tier 1 and 0 at 9.5% participation	$1.49	$5.15	$0.97	$41.14	$99.69
Estimated cost with increased discounts for Tier 1 and 0 at 11.0% participation	$1.62	$5.59	$1.05	$44.70	$108.31
Estimated cost with increased discounts for Tier 1 and 0 at 12.5% participation	$1.75	$6.04	$1.14	$48.26	$116.93

Q. Is Staff's concern regarding cost recovery potentially at odds with the Coalition's suggestions for deeper discounts?

A. Likely yes. Providing deeper discounts will necessarily create additional expense for the program. Also, as explained above, the Coalition's suggestion for deeper

discounts, similar to the other Oregon LDCs, fails to consider the availability of NW Natural's other bill assistance programs, which the other LDCs do not have.

Q. Are cost caps currently in place for each customer class, and what is the Company's rationale for capping cost recovery?

A. To be clear, the current recovery of costs for the bill discount program does not include cost caps, per se. As Staff indicates, NW Natural's cost recovery for the bill discount program "is set up as a fixed dollar charge for all general service schedules. This structure effectively caps recovery from each customer type at the level of the fixed dollar charge."[64] The fixed charge cost recovery in Schedule 335 is the direct result of stakeholder feedback during the ADV 1390 proceeding, where NW Natural heard a clear preference for fixed charge recovery.

Q. Staff expresses concern about the Company's decision to structure cost recovery for the bill discount program as a fixed dollar charge.[65] Please explain the Company's decision to structure the program as a fixed charge per bill.

A. This approach came directly from stakeholder feedback. Back in February 2022, before NW Natural filed its bill discount program proposal, several opportunities for stakeholder feedback were offered, including a workshop, follow-up call and available office hours for stakeholders. We heard a clear preference for a per-bill charge. As a result, we adopted the per-bill charge and included it in our initial

[64] Staff/300, Scala/11.

[65] Staff/300, Scala/11-12.

filing in April 2022. During the four workshops and comments that followed in the docket ADV 1390 procedural schedule, we did not get any feedback that disagreed with that approach.

Further, NW Natural finds a fixed-bill cost recovery design to be appropriate for the bill discount program, which is a program offered to residential customers and is recovered from all residential, commercial, and industrial customers. Importantly, costs of the bill discount program are allocated on an equal-percentage-of-margin basis to each customer rate schedule, using the current approved rate structure. From there, per-bill rates are derived at the rate schedule level for Rate Schedules 2, 3, 27, 31, and 32.

We find this cost recovery to be appropriate, as costs are appropriately allocated to customer classes commensurate with the current approved rate design that was informed by the last long-range incremental cost study. In addition, the per-bill charge smooths the impact of the cost to customers and removes the impact of the seasonality of gas usage and mitigates the potential for under- or over-collecting the costs of the program. Further, any potential for cost-shifting is minimized because the costs of the bill discount program are tracked in a balancing account, so any under- or over-collected costs are taken into account during the annual update to rates for the program's cost recovery.

Q. Could shifting to a volumetric rate for funding the bill discount have consequences for low-income, high-use customers?

A. Yes. Research from the American Council for an Energy-Efficient Economy ("ACEEE") found that low-income households pay 15 percent more per square foot

for energy compared to the average household ($1.41/ft² and $1.23/ft², respectively). A 2021 study reported in *Proceedings of the National Academy of Sciences*[66] supported these findings and showed that when evaluating annual energy use, on average, homes in the lowest income neighborhoods had 25-60 percent higher energy use per square foot compared to the highest income neighborhoods. The study also found that even within income groups, predominantly non-white neighborhoods had higher energy use intensity (per square foot) compared to predominantly white neighborhoods. In light of these concerns, the Company prefers to employ caution in structuring a per therm charge where the impact on energy burden could be lower for those low-income/high usage customers. Further, a volumetric charge would lead to overcollection during cold weather and under-collection in warm weather, but a fixed charge makes it more predictable for customers.

Q. Please respond to Staff's recommendation that the Commission reject the changes to the bill discount program until the Company provides more detailed information regarding cost recovery.[67]

A. As explained above and in my Direct Testimony,[68] NW Natural's proposal to improve the current design of the bill discount program by increasing the discounts for Tier 1 and 0 will provide meaningful benefit to program participants, mitigate

[66] Kangkang Tong et al, *Measuring social equity in urban energy use and interventions using fine-scale data*, 118 PNAS 24 (Jun. 15, 2021) (available at https://www.pnas.org/doi/10.1073/pnas.2023554118).

[67] Staff/1200, Lockwood/27-28.

[68] NW Natural/200, Tanaka/22-23.

energy burden by targeting 3 percent and is well-supported. And as discussed above, the rate design of the Company's current cost recovery of the bill discount program through per-bill charges remains an efficient and equitable methodology. Finally, in response to Staff's request, NW Natural prepared an analysis of potential program costs assuming different participation levels, as shown above in Tables 6 and 7.

Q. How do you respond to CUB's suggestion to require a report on rate shock mitigation through the bill discount program?[69]

A. As indicated in my Direct Testimony, NW Natural has analyzed and demonstrated our review of the current tools available to help mitigate rate changes and energy burden. That analysis showed that we are continuing to have effective mitigation tools to help reduce energy burden, thus helping to insulate the impacts of rate changes on customers most in need. The Company opposes a formal requirement to file a plan on rate shock given that it already provides periodic reports on its existing rate mitigation tools.[70] Adding another filing is unnecessary because it is an inefficient use of Commission, stakeholder, and Company resources and creates barriers to access for those who cannot get involved in a rate case or other Commission proceeding.

[69] CUB/100, Jenks/15.

[70] NW Natural's OLGA Annual Report is filed in docket RG 10, the OLIEE Annual Report is filed in docket RG 13, and the quarterly bill discount report is filed in docket RG 102.

III. 2022 LINA / 2024 EBA

Q. Please describe Staff's and the Coalition's testimony about the LINA.

A. Staff notes that the Company should make use of the LINA to identify households that may be eligible for programs such as the OLIEE.[71]

The Coalition testified that the LINA uses too small a sample size and does not include granular, customer-specific data.[72] It took issue with the Company's reliance on census tract data and averaged data estimates, arguing that the Company should instead gather customer demographics from Community Action Partner ("CAP") agencies or credit bureaus to create a dataset of customer addresses that includes detailed information such as household income, age of occupants, and homeownership status.[73] The Coalition states that the SSS is a superior form of measurement of customer's energy burden because it determines the amount of income a household needs to afford a variety of basic expenses. The Coalition argues that the SSS provides better insight into the level of income a household needs to avoid being burdened by energy costs.[74]

[71] Staff/1200, Scala/12-15.

[72] Coalition/300, Fain-Segovia Rodriguez-Daryanani/10-11.

[73] Coalition/300, Fain-Segovia Rodriguez-Daryanani/11-13.

[74] Coalition/300, Fain-Segovia Rodriguez-Daryanani/14-15.

Q. Has the Company been able to use the data from the LINA to identify zip codes of low-income customers who may be eligible for bill discounts or OLIEE funds?

A. As discussed above, while it was not a deliverable of the first LINA, we plan for the 2024 EBA to provide granular information about energy burdened customers, by zip code and/or census tract.

Q. Please respond to the Coalition's assertion that the LINA sample size was too small.

A. AEG, the expert on this matter, detailed its multi-stage recruitment effort to get as large as a set of survey responses as possible. This included:

1. A postcard survey invitation was mailed to 4,520 Oregon customers (3,900 urban and 620 non-urban) and 1,233 Washington customers (1,000 urban and 233 non-urban) based on the established quotas.
2. A week after the initial mailing, a second invitation postcard was sent to the same sample.
3. AEG mailed the invitation to an additional 1,000 Washington customers in the sample frame to increase the sample pool.
4. Finally, AEG emailed the survey to Oregon and Washington NW Natural Residential Insight Panel members, regardless of whether they were likely to qualify for the survey. A total of 1,616 customers completed the screening portion of the survey. Of those, nearly **25 percent (370)** of respondents were income qualified.

Q. Does the Company have any concerns about the Coalition's recommendation that it gather customer demographics from CAP agencies or credit bureaus to create a dataset of customer addresses that includes detailed information such as household income, age of occupants, and homeownership status?[75]

A. Yes. The Company does have concerns about this recommendation, such as:

- Privacy Concerns: Collecting personal information without explicit consent can raise privacy issues and legal risks.
- Utility Overreach: Gathering detailed customer demographics at this level may be invasive.
- Trust Erosion: Data collection can erode trust between utilities and customers—especially vulnerable communities and harder to reach households who may become wary of sharing information and further disengage from utility programs.
- Operational Complexity: Managing large datasets requires significant resources and storing detailed demographics increases the risk of data breaches.

Q. What are the Company's plans for improving the next EBA?

A. As reported in the March 13, 2024, workshop mentioned above, NW Natural is working with Empower Dataworks to conduct an EBA that will collect and aggregate data related to energy bills, program participation and customer

[75] Coalition/300, Fain-Segovia Rodriguez-Daryanani/11-13.

demographics to support our understanding of energy burden among residential customers, building a data foundation to evaluate program performance, inform program design and improve marketing and research. The EBA will be completed by the fall of 2024.

IV. OLIEE

Q. Please describe Staff's and intervenors' testimony regarding the OLIEE program.

A. Staff acknowledges that the Company has been working to expand spending on its OLIEE program and has recently removed project caps for projects that meet its qualifications.[76] However, Staff encourages the Company to increase enrollment of its OLIEE program with targeted design and outreach and to close the gaps it observes between OLIEE projections and completions.[77]

The Coalition provides a number of suggestions related to OLIEE spending, including increasing spending and eliminating restrictions on funding.[78] Specifically, the Coalition recommends the Commission require NW Natural to change the structure of its OLIEE program to (1) remove financial caps on spending per dwelling to "encourage spending of existing program funds"; (2) increase the budget for health and safety repairs to $10,000 per home to enable CAP agencies to make repairs for home weatherization and appliance upgrades;

[76] Staff/300, Scala/14.

[77] Staff/300, Scala/13.

[78] Coalition/300, Fain-Segovia Rodriguez-Daryanani/31-32, 38.

and (3) remove the requirement to replace gas appliances with new gas appliances and instead permitting OLIEE fund recipients to choose electric heat pumps.[79]

The Coalition also indicates that the Company should use the revised LINA to identify customers eligible for OLIEE funds, testifying that the Company has not reached enough customers and has failed to disburse funding appropriately.[80] The Coalition recommends that the Commission require the Company to "improve [OLIEE] administration" by (1) using OLIEE funds to target customers with high energy burden; (2) developing a communications plan to advertise the OLIEE program; and (3) spending at least $2.5 million of existing OLIEE funds on the Open Solicitation Program ("OSP").[81]

Further, the Coalition recommends the Commission prohibit NW Natural from making changes to the OLIEE program through tariff filings and instead require that the Company make any changes in a rate case.[82]

Q. How do you respond to the Coalition's statement that the Company allowed OLIEE funding to build up and then "cut funding completely" to OLIEE?[83]

A. This is a mischaracterization of the Company's work on expanding OLIEE. The Company has remained forthcoming and transparent about the build-up of OLIEE funds with our Advisory Committee and in our annual OLIEE reports. The timing

[79] Coalition/300, Fain-Segovia Rodriguez-Daryanani/47.

[80] Coalition/300, Fain-Segovia Rodriguez-Daryanani/40.

[81] Coalition/300, Fain-Segovia Rodriguez-Daryanani/47-48.

[82] Coalition/300, Fain-Segovia Rodriguez-Daryanani/32.

[83] Coalition/300, Fain-Segovia Rodriguez-Daryanani/37.

of the funding pause was consistent with when we typically update the public purpose charge. The Company previewed this with the OLIEE Advisory Committee several times during 2023. Additionally, NW Natural provided information about the OLIEE funding balance in its last rate case, docket UG 435, NW Natural/2200, Moerlins/15-16.

Much of the OLIEE build-up is due to the Company increasing the surcharge on customer bills earmarked for OLIEE in early 2020 immediately prior to COVID restrictions falling into place. Then, although the Company had expected to collect and spend a higher amount of funds that year, COVID restrictions and related supply chain issues limited the amount of work that could be done and funds that could be spent. Since then, the Company has taken targeted action to spend those funds down without over-collecting from customers.

Q. Please explain how the Company works with CAPs to disburse OLIEE funds.

A. CAP agencies have multiple sources of funding and they blend these funds to maximize the energy efficiency upgrades that a client receives. Once a project is completed, a CAP agency will provide NW Natural the necessary information to receive reimbursement for the weatherization project. NW Natural notes that the funding sources for weatherization projects are not transparent to the customer; customers are unable to choose the funding sources with which to work. The agencies have waitlists for customers to receive these services, and once a customer is able to access the program, an audit is done to determine the best mix of services and funding sources for that specific customer.

Q. Keeping in mind these limitations, how has the Company attempted to address underspending of OLIEE funds?

A. As further described below, NW Natural has worked with its OLIEE Advisory Committee on tariff changes that broadened the reach of funding to customers and for measures, restored delivery of the OSP, and leveraged enhanced outreach for the Company's low-income programs. Additionally, NW Natural is working with OSP partners to address some of the gaps observed in specific service areas like Coos Bay and Hood River.

Q. The Coalition recommends that NW Natural remove financial caps on spending per dwelling and increase the limit for health and safety repairs performed with OLIEE funds to $10,000.[84] How do you respond?

A. These recommendations are moot. As discussed in the April 25, 2024 UG 490 Environmental Justice Issues Workshop, and as signaled in my Direct Testimony,[85] NW Natural worked with our OLIEE Advisory Committee to develop changes to Schedule 320 to expand the reach to customers and provide more support for projects and to ease the administrative burden of the agencies that administer OLIEE projects. The tariff filing was docketed as ADV 1593 and approved by the Commission at its March 19, 2024 Public Meeting, and the revised tariff pages

[84] Coalition/300, Fain-Segovia Rodriguez-Daryanani/39.

[85] NW Natural/200 Tanaka/28.

became effective March 20, 2024.[86] The approved changes removed the project reimbursement caps.

Q. The Coalition states "NW Natural does not perform any outreach to the public regarding its OLIEE program."[87] Is the Coalition's statement true?

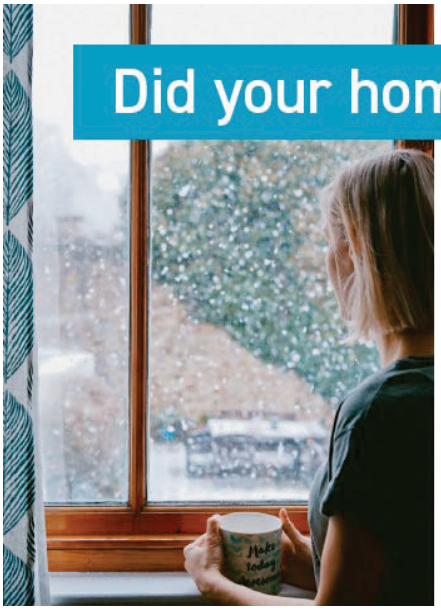
A. No, the Coalition's statement is incorrect and misrepresents the information provided. The statement incorrectly assumes that the examples presented in my Direct Testimony[88] are the only methods of outreach the Company performs regarding the OLIEE program. In contrast, as detailed in my Direct Testimony, those instances are merely demonstrations of how our partner CAP agencies effectively utilize energy education funds.

NW Natural further detailed outreach for its OLIEE Program in response to Coalition data requests. Below are additional examples of outreach material that have been produced by NW Natural to promote partnerships with community action agencies across the service territory, as well as for cross promotion of the bill discount program. These educational outreach materials are distributed at community events and through a trusted network of community partners.

[86] See *NW Natural Advice No. 24-02, Schedule 320 OLIEE Programs*, Docket No. ADV 1593, Staff Memo (Mar. 19, 2024).

[87] Coalition/300, Fain-Segovia Rodriguez-Daryanani/42.

[88] NW Natural/200, Tanaka/26.



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Q. How does the Company respond to the Coalition's recommendation that the Commission require the Company to prepare a communication plan to inform customers about OLIEE?

A. The Company currently is working on such a communication plan. We have developed several pieces of outreach that our customers interact with at different events or through our partners and we are working on mapping these communication pieces.

Q. Has the Company dedicated funds to reaching customers who qualify for OLIEE?

A. Yes, we have committed $2.5 million of the built-up OLIEE funds for use in the OSP. As indicated in my Direct Testimony,[89] OSP serves as a funding vehicle or

[89] NW Natural/200, Tanaka/25.

tool to unlock, expedite, and streamline the delivery of energy efficiency projects that help low-income customers reduce energy usage, save money and live in healthier homes. The OSP was introduced to Schedule 320 in 2013 as a supplemental, complementary resource to increase and accelerate the delivery of weatherization services to income-eligible households while adhering to the spirit of the OLIEE program.

Since the relaunch of the program, OSP has delivered nearly $3 million in energy efficiency and weatherization funding and served roughly 630 low-income households and families. Spending reached this level after the program was dormant for several years to refine reporting and process document practices, enable higher transparency and establish staffing capacity to lead the program.

Q. Is the Company performing targeted outreach of communities that could benefit from OLIEE funds?

A. Yes, the Company is actively pursuing targeted outreach of communities that could benefit from OLIEE through bill inserts and through other wide-reaching mechanisms, such as a billboard in Washington County.

Q. The Coalition recommends that OLIEE funds be used for a different purpose, such as electrification. How does the Company respond?

A. The Company does not believe it is proper to require customers to pay into a public purpose fund for a very specific use, and then unilaterally change that use after collection of those monies. The purpose of OLIEE is to promote energy equity, energy affordability and health outcomes for income-eligible customers through energy efficiency upgrades. OLIEE finances weatherization projects and energy

literacy for income eligible customers such that: energy savings are maximized; customers are warm, empowered and healthy; and low-income housing stock is increasingly durable. In addition, OLIEE funds typically only upgrade appliances while full electrification of a household will require additional funding from a source intended to undertake such large projects.

Second, there are federally-funded rebate programs available for heat pump installations, and low-income customers can qualify for a rebate of up to $8,000 for a heat pump—likely covering the entire cost. As a matter of principle, it does not make sense to redirect funds paid for by natural gas customers to fund electric appliance installation. However, the fact that there is a separate funding pool for heat pumps makes this proposal even more unreasonable.

Finally, the Company questions the use of customer funds to remove gas infrastructure and limit investment in future gas customers. Instead, the Company is actively exploring energy efficiency solutions that leverage hybrid heating and cooling solutions leveraging the strengths of both the gas and electric systems. This is evidenced by NW Natural's participation in an HVAC pilot with all other Oregon investor-owned utilities administered by the Energy Trust of Oregon and the Company's support of a hybrid heat solution being implemented by the partner Homes For Good.

Q. Do you agree with the Coalition that electrification "promotes energy equity for low-income and other marginalized communities"[90]?

A. No. The statement that electrification promotes energy equity is an oversimplification to an issue that is much more complicated and nuanced. Electrification is not inherently a more equitable energy solution across multiple assessments of energy equity.

First, electrification is not more affordable. In 2022, the U.S. Department of Energy reported that natural gas is 3.4 times more affordable than electricity and significantly more affordable than several other residential energy sources for the same amount of energy delivered. [91] January 2024 data show that natural gas heat costs in Oregon are roughly 40 percent of the price of electric heat, on a per unit heat basis.[92]

Second, electrification is not more energy efficient. In 2023, 38 percent of Oregon's total net generation of electricity was provided by natural gas fired power plants.[93] And during the process of burning gas to generate electricity, more than

[90] Coalition/300, Fain-Segovia Rodriguez-Daryanani/42.

[91] U.S. Dept. of Energy, 87 Fed. Reg. 12681, Table 1 (Mar. 2, 2022).

[92] Anne Lauer, *Natural Gas Heat vs Electrical Heat – Which is Cheaper – 2024*, SHRINK THAT FOOTPRINT (Jan. 2024) (available at https://shrinkthatfootprint.com/natural-gas-heat-vs-electrical-heat/) (compiling data prepared by the U.S. Energy Information Administration).

[93] U.S. Energy Info. Admin., *Oregon State Profile and Energy Estimates: Electricity* (Apr. 18, 2024) (available at https://www.eia.gov/state/analysis.php?sid=OR#:~:text=Natural%20gas%20fuels%20the%20second,the%20state's%20total%20net%20generation).

half of the heat energy in the fuel is lost[94]–a far more inefficient process than direct gas use.

Third, electrification does not boost resiliency efforts. Rather than make our networks and critical systems more resilient and less vulnerable to disruptions, electrification concentrates our dependence on a single network.

Q. The Coalition recommends the Commission prohibit NW Natural from making changes to the OLIEE program through tariff filings and instead require that the Company make any changes in a rate case to ensure participation by environmental justice groups.[95] How do you respond?

A. First, it is difficult to square that recommendation with the Coalition's statement that "rate cases deny low-income Oregonians meaningful participation in the rate-making process and conflict with the principles of procedural equity and justice."[96] Second, NW Natural already facilitates an existing process with its OLIEE Advisory Committee, which includes members from community action agencies, Staff, and CUB, to discuss any potential changes and suggestions to the OLIEE program. The OLIEE Advisory Committee meets regularly to discuss the status of the OLIEE program and to vet any needed changes or improvements to OLIEE. We find that this existing process is far more inclusive and collaborative and furthers the principles of procedural equity and energy justice.

[94] Karin Kirk, *Energy loss is single-biggest component of today's electricity system*, YALE CLIMATE CONNECTIONS (Oct. 24, 2022) (available at https://yaleclimateconnections.org/2022/10/energy-loss-is-single-biggest-component-of-todays-electricity-system/).

[95] Coalition/300, Fain-Segovia Rodriguez-Daryanani/32.

[96] Coalition/300, Fain-Segovia Rodriguez-Daryanani/49.

V. MISCELLANEOUS ENERGY JUSTICE ISSUES

A. Messaging and Advertising Program Availability

Q. Please describe the Coalition's testimony regarding Company advertising of the availability of the bill discount program and OLIEE to customers.

A. The Coalition testifies that Company failed to educate customers regarding the availability of its bill discount program.[97] The Coalition also testifies the Company has not sufficiently advertised its OLIEE program.[98] The Coalition takes issue with this as the reason for its assertion that the enrollment is low at this time.[99] As the Company testified in Direct Testimony, the Company has informed customers about its programs through a variety of avenues, including targeted outreach, direct engagement, and paid ads.[100] In addition, the Coalition's criticism seems to be based on the LINA survey results conducted by AEG. That LINA survey was conducted many months before the bill discount program was even finalized and implemented.

Q. What steps has NW Natural taken to communicate the availability of the bill discount program to customers?

A. NW Natural has spent countless hours refining and amplifying its bill discount program offerings. Its outreach strategy and materials are often duplicated and modeled by other utilities. To state that the Company failed to advertise the bill

[97] Coalition/200, Apter-Connolly/35-36.

[98] Coalition/200, Apter-Connolly/36.

[99] Coalition/300, Fain-Segovia Rodriguez-Daryanani/26.

[100] NW Natural/200, Tanaka/17.

discount program or the OLIEE is false. Please also refer to NW Natural/3200, Beck for additional details regarding the robust outreach related to the Company's bill discount program.

B. CEAG

Q. Did parties comment on NW Natural's CEAG?

A. Yes, Staff testifies generally in support of the CEAG and its role in providing diverse, equitable and inclusive input for the Company and its makeup of community members. Staff indicates that it can envision improvement regarding the visibility of the CEAG, the Company's level of accountability to the CEAG, and Company's commitment to expanding the CEAG's influence.[101]

Q. How do you respond to Staff's comments on the CEAG?

A. The Company is encouraged by Staff's positive reaction to the CEAG and is open to collaborating on avenues for developing the CEAG. In developing the CEAG, the Company and CEAG members developed guidelines and a charter that govern CEAG meetings and its relationship with the Company. These guidelines and charter documents limit the ability of the Company to open meetings up to other participants or add meetings to the CEAG's schedule.

However, the Company is interested in an ongoing dialogue with Staff to provide updates regarding work with the CEAG when appropriate. For example, the Company can envision having Staff meet with the core internal CEAG group periodically to provide updates and answer questions.

[101] Staff/300, Scala/15-17.

NW Natural is committed to an authentic and effective process: a core tenet of the group is to solicit ideas and encourage engagement from new perspectives, voices, and lived experiences in an authentic way—avoiding the pitfalls of diversity, equity and inclusion work that can be transactional and performative. Examples of how we are fulfilling this commitment include:

- Center meetings on actionable asks of group.
- Hire third party consultants.
- Compensate groups.
- Formalize feedback and accountability measures (also formalized in CEAG charter).
- Source meeting topics based on feedback from CEAG members.

Q. What actions is the Company taking to ensure transparency on the CEAG and its recommendations?

A. The Company has held numerous meetings to share information and updates on the CEAG rollout. We have also emphasized and encouraged feedback and follow-up from stakeholders.

Q. Does this conclude your Reply Testimony?

A. Yes, it does.

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NW Natural

Reply Testimony of Brody J. Wilson

COST OF CAPITAL
EXHIBIT 2400

REDACTED

June 4, 2024

EXHIBIT 2400 – REPLY TESTIMONY – COST OF CAPITAL

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I. Introduction and Summary

Q. Are you the same Brody Wilson who provided Direct Testimony on NW Natural Gas Company dba NW Natural's ("NW Natural" or "the Company") cost of capital?

A. Yes, I presented NW Natural/300, Wilson.

Q. Please summarize your Reply Testimony.

A. NW Natural continues to request a capital structure of 50 percent equity and 50 percent debt for ratemaking purposes, which Public Utility Commission of Oregon Staff ("Staff") supports. The Company works to keep its actual capital structure at or near 50/50, but the capital structure always fluctuates over time. The Alliance of Western Energy Consumers' ("AWEC") argument for a capital structure of 48 percent equity and 52 percent debt is based on a single point in time and ignores these natural fluctuations. AWEC also misrepresents the reasons for the Company's recent debt issuances. With respect to the Company's credit rating, S&P Global updated NW Natural's outlook from negative to stable, but concerns about the Company's credit metrics persist.

Q. Do you include any exhibits with your testimony?

A. Yes, I am presenting the following exhibits: NW Natural/2401, Wilson (Long- and Short-Term Interest Rates); NW Natural/2402, Wilson (AWEC's Response to NW Natural Data Request No. 11); and NW Natural/2403, Wilson (S&P Global Ratings Research Update).

II. Capital Structure

Q. Do you have any updates to NW Natural's requested capital structure for ratemaking purposes in this proceeding?

A. No. The Company continues to request that the Commission adopt for NW Natural a 50/50 capital structure for ratemaking purposes. I would note that the parties settled the embedded cost of long-term debt at NW Natural's requested 4.712 percent, and the rest of NW Natural's requested capital structure remains unchanged from my Direct Testimony. The following table presents the proposed capital structure along with the calculation of the Company's rate of return for the Test Year:

Table 1. Requested Capital Structure and Rate of Return

Component	Ratio	Cost	Weighted Cost
Long-term Debt	50%	4.712% (settled)	2.356%
Common Equity	50%	10.1%	5.050%
Total	**100%**		**7.406%**

Q. Does Staff support the Company's proposed 50/50 capital structure?

A. Yes. Staff recommends that the Commission adopt NW Natural's proposed 50/50 capital structure, consistent with the capital structures adopted for Cascade Natural Gas and Avista.[1] Staff notes that while the Company's actual capital structure has fluctuated a bit over the past five years, the Company has maintained

[1] Staff/1600, Pileggi/3.

a capital structure near 50/50 over that period.[2] Regarding the fluctuations, Staff explained that they "are expected as issuances, redemptions, and maturations on financial instruments are not in perfect sync" and further that it is not "always beneficial for the company to maintain a perfectly uniform capital structure."[3]

Q. Why has the Company maintained a capital structure at or near 50/50?

A. The Company works to keep its capital structure at or near 50/50 to balance the twin goals of keeping rates low and ensuring access to capital markets on favorable terms.

Q. Does any party oppose NW Natural's proposed capital structure?

A. Yes. AWEC argues NW Natural did not justify the reasonableness of its proposed capital structure relative to its actual capital structure and recommends that the Commission adopt a capital structure for NW Natural of 52 percent debt and 48 percent equity to align with NW Natural's actual capital structure expected at the beginning of the rate-effective period.[4]

Q. Is AWEC's proposal reasonable?

A. No. As I noted in my Direct Testimony, and as understood by Staff, NW Natural's capital structure—indeed, the capital structure of any company—will naturally fluctuate over time.[5] Confidential Figure 1 below shows the fluctuation in the Company's percent equity over time and projected future fluctuations.

[2] Staff/1600, Pileggi/3.

[3] Staff/1600, Pileggi/2.

[4] AWEC/100, Mullins/2, 15.

[5] NW Natural/300, Wilson/3.

[BEGIN CONFIDENTIAL]

Figure 1. Equity Percentage Fluctuation Over Time

[END CONFIDENTIAL]

Given the natural variation in equity and debt percentages, it is simply unreasonable to set capital structure based on a single point in time as AWEC proposes.

Q. Can you provide more insight into some of the timing issues that result in fluctuations in NW Natural's capital structure, specifically?

A. Yes. NW Natural receives equity contributions on a regular basis from the parent company consistent with the parent company's at-the-market ("ATM") program, which issues smaller amounts of equity during open trading windows for the Company. In contrast, the Company makes its debt issuances episodically, based on both its overall needs and market conditions. Therefore, the Company can be above or below the targeted 50/50 capital structure due to the timing and size of the financings. If the Company makes a significant debt issuance in order to take

advantage of a favorable debt market, it can take us more than 12 months to catch back up through the issuance of equity through our ATM. Nevertheless, NW Natural is and historically has been committed to the goal of a 50/50 capital structure and is always working to move toward that target.

Q. AWEC points out that the Company's expected average actual capital structure over the 12-months ending October 31, 2025 is 51 percent debt, 49 percent equity.[6] Is AWEC correct and if so, should the Commission consider setting the Company's capital structure at 51/49 debt/equity instead of 50/50?

A. AWEC is correct that the Company's expected actual capital structure over that time period is 51 percent debt, 49 percent equity. However, the Commission should not depart from the Company's 50/50 capital structure for ratemaking purposes based on that calculation. First, just as NW Natural targets a 50/50 actual capital structure in order to balance low rates with favorable market access, I understand that the Commission has stated that it also views a 50/50 capital structure as representing an optimum balance for ratemaking purposes.[7] I understand that it is the Commission's policy to maintain that balance when setting rates, even where the utility's actual capital structure may vary from 50/50. Second, as I have explained above, NW Natural has always stayed and will continue in its goal to stay at or near a 50/50 capital structure and expects to

[6] AWEC/100, Mullins/14-15.

[7] *In re PacifiCorp Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 at 22-25 (Dec. 18, 2020).

achieve that target in 2025. There is no reason for the Commission to depart from a 50/50 capital structure for ratemaking purposes simply because a Company's actual structure might be slightly different.

Q. AWEC notes NW Natural has issued a significant amount of debt in the past year—more than double prior years.[8] Is AWEC correct?

A. Yes, early last year the Company accelerated $100 million of debt issuances planned for 2024 in order to take advantage of favorable market conditions. As context, in 2022 and 2023, the market saw a consistent rise in interest rates, making borrowing increasingly expensive. However, March 2023 saw an inversion in the yield curve, which made borrowing short-term commercial paper more expensive than long-term debt. Given the rising interest rate environment, the Company decided to take advantage of less expensive long-term debt in order to de-risk future issuances. This was also a period that followed a volatile gas price market in winter 2022 and ensured sufficient liquidity for the utility through the winter. In short, after a long period of interest rate hikes and uncertainty in the macroeconomic picture, March 2023 offered a window of stable interest rates. Therefore, the Company determined that it was in the Company's and customers' best interests to issue the $100 million of debt at that time. See Exhibit NW Natural/2401, Wilson, which shows the short and long-term interest rates between January 2022 and December 2023.

[8] AWEC/100, Mullins/15.

Q. AWEC claims that NW Natural is diluting its own capital structure to finance water company acquisitions at the holding company level.[9] Has AWEC explained what it means by this allegation?

A. Yes. In response to NW Natural Data Request No. 11, which inquired about the facts underlying AWEC's claims, AWEC explained that "NW Natural appears to have acquired a large volume of water companies in 2022 and 2023," and that "the timing of these acquisitions corresponds to the timing of the major increase in annual debt issuances by NW Natural."[10] Based on this response, it appears that AWEC believes the gas company has been using utility debt to acquire water companies.

Q. What is your response?

A. The notion that NW Natural is using debt issuance proceeds to acquire water companies is patently false. NW Natural Water Company, LLC ("NW Natural Water"), a separate subsidiary of Northwest Natural Holding Company ("NW Natural Holdings"), is the entity that acquires water companies. All payments for such water companies are made by the appropriate subsidiary within the water company structure. NW Natural, as a ring-fenced entity, operates separately from other corporate entities within the NW Natural Holdings family that are not subject to ring-fencing. Books, records, bank accounts and other aspects of NW Natural and NW Natural Water's businesses are kept separate. Additionally, under ring-

[9] AWEC/100, Mullins/15.

[10] NW Natural/2402, Wilson/1.

fencing provisions imposed on NW Natural by the Commission, no transaction between NW Natural and NW Natural Water is permitted without regulatory approval. Transactions between NW Natural and NW Natural Water are limited to those that are regulatorily permitted and are included on annual filings with the Commission. Examples of such transactions include shared services pursuant to NW Natural's Commission--approved Shared Services Agreement.

III. Credit Ratings

Q. What are NW Natural's current debt ratings?

A. The table below and NW Natural/301, Wilson show the Company's current ratings for each type of debt security from Moody's Investor Service ("Moody's") and Standard and Poor's Ratings ("S&P"), as well as the outlook issued by each agency.

Table 4. Current Ratings

	Moody's	S&P
Corporate	n/a	A+
Secured	A2	AA-
Commercial Paper	P-2	A-1
Outlook	Stable	Stable

Q. Has any of the information in Table 4 changed since your Direct Testimony was filed in December 2023?

A. Yes. In April 2024, S&P issued a report updating the Northwest Natural Gas Company outlook from negative to stable.[11] NW Natural sees this as a positive development. That said, concerns persist about NW Natural's credit metrics, as discussed in detail in NW Natural/2500, Coyne-Nelson. Over the past few years, NW Natural's earned return on equity ("ROE") has been modestly weaker than its authorized ROEs, reflecting a potential weakening of its ability to earn its authorized ROE. Additional concerns related to the energy transition risks in Oregon and Washington could be increasing if not managed appropriately by policymakers, regulators, and the Company.

Q. Does this conclude your Reply Testimony?

A. Yes.

[11] NW Natural/2403, Wilson/3, 8.

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Exhibits of Brody J. Wilson

COST OF CAPITAL
EXHIBITS 2401 – 2403

June 4, 2024

EXHIBITS 2401-2403 – COST OF CAPITAL

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Exhibit of Brody J. Wilson

COST OF CAPITAL
EXHIBIT 2401

This exhibit is being filed in its native, Excel format.

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Exhibit of Brody J. Wilson

COST OF CAPITAL
EXHIBIT 2402

June 4, 2024

NW NATURAL DATA REQUEST 11 TO AWEC:

AWEC/100, Mullins/15 states: "The timing and amount of major debt issuances appears to correspond generally to certain water company acquisitions."

a. Please identify each debt issuance and water company acquisition relied on to support this statement.
b. Please produce all documents relied on to support this statement.

AWEC RESPONSE:

AWEC objects to this request on the basis that it requests information about the timing and cost of water company acquisitions which NW Natural possesses and which it declined to provide AWEC in discovery. In AWEC Data Request 36, AWEC requested information about water company acquisitions, which NW Natural did not provide, claiming that such information was irrelevant. Notwithstanding said objection, AWEC responds as follows:

Based on the information AWEC reviewed and had available to it, NW Natural appears to have acquired a large volume of water companies in 2022 and 2023. In 2023, NW Natural closed Hiland Water, Truxton Canyon Water Company, Cerbat Water Company. In 2022 NW Natural closed seven water and wastewater utility transactions , including its largest water and wastewater acquisition ever in Yuma, Arizona. While NW Natural did not provide information about these acquisitions in discovery, AWEC's understanding is that NW Natural has spent over one hundred million on these acquisitions. As the quote states, the timing of these acquisitions corresponds to the timing of the major increase in annual debt issuances by NW Natural.

Response Date: May 10, 2024
Witness(es) Most Knowledgeable About Response: Bradley Mullins

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NW Natural

Exhibit of Brody J. Wilson

COST OF CAPITAL
EXHIBIT 2403

June 4, 2024

S&P Global
Ratings

RatingsDirect®

Research Update:

Northwest Natural Holding Co. Downgraded To 'A'; Outlook Negative; Subsidiary Ratings Affirmed, Outlook To Stable

April 19, 2024

Rating Action Overview

- We concluded our review of the insulating measures in place and determined that they are sufficient to potentially rate Northwest Natural Holding Co. (NWNH) subsidiary Northwest Natural Gas Co. (NWNG) up to two notches higher than its parent's group credit profile (GCP). We also assess the cumulative value of these insulating measures as increasing risk for parent NWNH because they limit or even materially restrict NWNH's access to NWNG's cash flows.
- Consequently, we lowered our rating on parent NWNH to 'A' from 'A+'. The outlook is negative.
- At the same time, we revised our outlook on subsidiary NWNG to stable from negative and affirmed our ratings on NWNG, including the 'A+' long-term issuer credit rating (ICR), the 'A+' unsecured debt rating, the 'AA-' senior secured debt rating, and the 'A-1' short-term rating. The recovery rating on the senior secured debt remains '1+'.
- The stable outlook on NWNG reflects our assessment that the insulating measures in place are sufficient to potentially rate NWNG up to two notches above NWNH's GCP and as such a downgrade to NWNH would not directly lead to a downgrade at NWNG. The stable outlook also reflects our expectations that NWNG's stand-alone financial measures will consistently remain above our downgrade threshold. Specifically, we expect stand-alone funds from operations (FFO) to debt of 15%-18% through 2026.
- The negative outlook on NWNH reflects its weak consolidated financial measures for the current rating. FFO to debt in 2023 was around 12%, significantly below our 15% downgrade threshold. We expect financial performance in 2024 will remain weak but improve in 2025, primarily reflecting our expectations for a fair Oregon rate case order.

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Rating Action Rationale

Our downgrade of NWNH to 'A' from 'A+' reflects higher risks because of material restrictions of cash flows within the company's corporate group. NWNG accounts for about 95% of NWNH's consolidated cash flows. We assess the cumulative value of the insulation measures in place as sufficient to rate NWNG up to two notches above NWNH's GCP. However, these insulating measures limit and could materially restrict NWNH's full access to NWNG cash flows. These insulating measures include dividend restrictions, a non-consolidation opinion, and independent directors on NWNG's board of directors that have effective influence on decision-making and whose vote is required for a voluntary bankruptcy filing.

The negative outlook on NWNH reflects its historical weak financial measures and our expectation that financial performance will remain weak for 2024. Since 2020, NWNH's FFO to debt has been consistently below our 15% downgrade threshold. The company's historical financial underperformance reflects its rising capital investments, including multiple acquisitions of water utilities, which increased its leverage and weakened its financial measures. More recently, NWNH's financial measures have been negatively affected by higher interest rates, higher cash taxes, and inflationary pressures, including higher operating costs.

We expect the company's financial measures will remain challenged in 2024 due to its elevated capital spending plan, including water utility acquisitions, investments in renewable natural gas (RNG) projects, and ongoing infrastructure investments. We expect financial improvement beginning in 2025, primarily reflecting a fair Oregon rate case order. However, financial measures could remain weak for the current rating if elevated capital investments and cash flow deficits are primarily debt funded or the company's rate case order is significantly below expectations.

We affirmed our 'A+' rating on subsidiary NWNG. Our rating largely reflects NWNG's low-risk regulated gas distribution operations in Oregon and Washington. NWNG provides natural gas service to approximately 800,000 customers with 65% of its margin generated from residential customers, 25% from commercial customers, and 7% from industrial customers. The company benefits from stable and supportive regulatory environments in both jurisdictions where it operates, with purchased gas adjustments and environmental cost recovery, decoupling and a forward-looking test year in Oregon, and multiyear rate case fillings in Washington. We view these mechanisms as supportive to its financial measures, allowing the company to largely mitigate regulatory lag. However, over the past few years, the company's earned return on equity (ROE) has been modestly weaker than its authorized ROEs, reflecting a potential weakening of management's ability to manage regulatory risk.

We also view the energy transition risks in Oregon and Washington as potentially increasing business risk. Washington has implemented decarbonization mandates and Oregon is contemplating various decarbonization initiatives. Furthermore, several cities are contemplating the implementation of a gas ban for new gas connections. We assess these evolving risks as potentially negative for credit quality and will continue to monitor future developments.

We assess NWNG's financial risk profile using our low-volatility benchmarks, reflecting the low-risk nature of its natural gas distribution operations and its track record of effective management of regulatory risk. We assume continued use of regulatory mechanisms and rate riders to effectively manage regulatory risk, annual capital spending averaging of about $330 million, and annual dividends averaging of about $75 million. We expect NWNG's stand-alone financial measures to remain in the middle range of its financial risk profile category such that FFO to debt is 15%-18% through 2026.

We consider NWNG to be insulated from its parent NWNH. Based on the strength of the insulating measures, NWNG could potentially be rated up to two notches higher than NWNH's GCP. Currently, NWNG is rated only one notch higher than its GCP, limited by its 'a+' standalone credit profile.

The key insulating measures include:

- NWNG's financial performance and funding prospects are independent from those of the group.
- NWNG issues its own debt and has its own credit facility.
- NWNG is regulated by Oregon and Washington regulatory commissions.
- NWNG has dividend restrictions.
- NWNG's board is highly independent with 11 out of 12 board of directors being independent.
- Independent directors on NWNG's board have effective influence on decision making, and their votes are required for a voluntary bankruptcy filing.
- NWNG is unlikely to be drawn or forced into a NWNH bankruptcy.
- There is an independent third party which is the holder of the "golden share" whose vote is required to file for bankruptcy.

We revised our outlook on NWNG to stable reflecting the insulation measures and the strength of its stand-alone credit profile. The stable outlook reflects our view that NWNG, because of the cumulative value of the insulating measures, could potentially be rated up to two notches above its parent's NWNH GCP. Because of the insulating measures, a downgrade to parent NWNH would not directly lead to a downgrade at NWNG. In addition, the stable outlook reflects our expectation that the company will continue to effectively manage regulatory risk and maintain financial measures consistent with the middle range for its financial risk profile category. Specifically, we expect stand-alone FFO to debt of 15%-18% through 2026.

Outlook

Northwest Natural Holding Co. (NWNH)

The negative outlook on NWNH reflects its current weak financial measures and the possibility that financial measures could remain weak. Our base case assumes continued weak financial performance in 2024 and then for financial performance improvement in 2025. This improvement primarily reflects a fair Oregon rate case order, such that FFO to debt is consistently greater than 15%.

Downside scenario

We could lower our ratings on NWNH over the next 12 to 24 months if FFO to debt remains below 15%. We could also lower our ratings on NWNH if business risk increases. This could reflect an unfavorable rate case outcome, higher risks due to decarbonization mandates and potential gas bans, a weakening of the company's management of regulatory risk, or an inability to consistently earn its authorized ROE.

Upside scenario

We could affirm ratings and revise our outlook on NWNH back to stable over the next 12 to 24 months if FFO to debt improves to consistently greater than 15%, with no increase of business risk.

Outlook

Northwest Natural Gas Co. (NWNG)

The stable outlook on NWNG reflects our base-case assumption that NWNG will generate sufficient cash flows to maintain appropriate consolidated financial measures for the current rating, including FFO to debt of 15%-18% through 2026. The stable outlook also reflects our expectation of strong operating performance and effective management of regulatory risk.

Downside scenario

We could lower our rating on NWNG over the next 24 months if the company's consolidated financial performance weakens such that FFO to debt remains consistently below 15%.We could also lower our rating on NWNG if the company's business risk increases. This could reflect a higher risks due to decarbonization mandates and potential gas bans, a weakening of the company's management of regulatory risk, or an inability to consistently earn its authorized ROE.

Upside scenario

We could raise our rating on NWNG over the next 12 to 24 months if the company's financial performance improves such that FFO to Debt is consistently above 21%, with no weakening of business risk.

Company Description

NWNH is the holding company of NWNG, NWNR and NW Natural Water Co. LLC (NWWC). NWNG operates as a regulated natural gas distribution company, providing natural gas service to approximately 800,000 residential, commercial, and industrial natural gas customers in Oregon and Southwest Washington through 14,200 miles of pipeline systems. Approximately 90% of customers are in Oregon and 10% are in southwest Washington. NWNR is engaged in investing competitive RNG operations while NWWC owns and operates several regulated water utilities. Together, NWNR and NWWC contribute about 5% of NWNH's revenues while NWNG contributes the remaining 95% revenues.

Our Base-Case Scenario

- Modest customer growth and continued use of regulatory mechanisms.
- Continued negative discretionary cash flow.
- Annual capital spending averaging about $370 million over our forecast period.

- Small tuck-in regulated water utilities acquisitions funded in a credit supportive manner.
- Annual dividends averaging about $77 million.
- All debt maturities refinanced.

Liquidity

We assess NWNH's liquidity as adequate, with sources covering uses by 1.1x over the coming 12 months, and that its sources cover uses even if forecasted consolidated EBITDA declines by 10%. We believe the predictable regulatory framework for NWNH provides a manageable level of cash flow stability for the company even in times of economic stress, supporting our use of slightly lower thresholds to assess liquidity. In addition, NWNH has the ability to absorb high-impact, low-probability events, reflecting that the company maintains about $600 million in committed credit facilities through 2026, and our belief that the company can lower its high capital spending (averaging about $370 million annually) during stressful periods, indicative of a limited need for refinancing under such conditions.

Furthermore, our assessment reflects the company's generally prudent risk management, sound relationships with its banking group (which includes over four well-established banks). Overall, we believe the company can withstand adverse market circumstances over the next 12 months with sufficient liquidity to meet its obligations. The company has no large long-term debt maturity coming due, and we expect the company to proactively address any maturities well in advance of its scheduled due dates.

Principal liquidity sources

- Cash and cash equivalents of about $33 million;
- Credit facilities of about $600 million; and
- Cash FFO estimated of about $275 million.

Principal liquidity uses

- Debt maturities, including commercial paper outstanding of about $241 million;
- Capital expenditure (capex) of about $400 million; and
- Dividend payments of about $75 million.

Environmental, Social, And Governance

ESG factors have no material influence on our credit rating analysis of NWNH.

Issue Ratings - Subordination Risk Analysis

Capital structure

The short-term rating on NWNG is 'A-1', based on our 'A+' issuer credit rating on the company. As on Dec 31, 2023, NWNG's capital structure consists of approximately $1.4 billion first mortgage bonds. The company also maintains a medium-term note program which is currently not utilized.

Analytical conclusions

We rate NWNG's medium-term notes program 'A+', equal to its issuer credit rating, because we view any debt issued under this program as debt issued by a qualifying investment-grade utility.

Issue Ratings - Recovery Analysis

Key analytical factors

NWNG's first-mortgage bonds benefit from a first-priority lien on substantially all of the utility's real property, owned or subsequently acquired. Collateral coverage of more than 1.5x supports a recovery rating of '1+ and an issue-level rating one notch above the issuer credit rating.

Ratings Score Snapshot

Northwest Natural Holding Co.

Issuer credit rating: A/Negative/--

Business risk: Excellent

- Country risk: Very Low
- Industry risk: Very Low
- Competitive position: Strong

Financial risk: Intermediate

- Cash flow/leverage: Intermediate

Anchor: a+

Modifiers

- Diversification/portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Neutral (no impact)
- Comparable rating analysis: Neutral (no impact)

Stand-alone credit profile: a+

Group credit profile: a

Northwest Natural Gas Co.

Issuer credit rating: A+/Stable/A-1

Business risk: Excellent

- Country risk: Very Low
- Industry risk: Very Low
- Competitive position: Strong

Financial risk: Intermediate

- Cash flow/leverage: Intermediate

Anchor: a+

Modifiers

- Diversification/portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Neutral (no impact)
- Comparable rating analysis: Neutral (no impact)

Stand-alone credit profile: a+

Group credit profile: a

Entity status within group: Insulated (no impact)

Related Criteria

- Criteria | Corporates | General: Sector-Specific Corporate Methodology, April 4, 2024
- Criteria | Corporates | General: Corporate Methodology, Jan. 7, 2024
- Criteria | Corporates | General: Methodology: Management And Governance Credit Factors For Corporate Entities, Jan. 7, 2024
- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014

- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- Criteria | Corporates | Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Ratings List

Downgraded

	To	From
Northwest Natural Holding Company		
Issuer Credit Rating	A/Negative/--	A+/Negative/--
Ratings Affirmed; Outlook Action		
	To	**From**
Northwest Natural Gas Co.		
Issuer Credit Rating	A+/Stable/A-1	A+/Negative/A-1
Ratings Affirmed; Recovery Ratings Unchanged		
Northwest Natural Gas Co.		
Senior Secured	AA-	AA-
Recovery Rating	1+	1+
Ratings Affirmed		
Commercial Paper	A-1	A-1

Certain terms used in this report, particularly certain adjectives used to express our view on rating relevant factors, have specific meanings ascribed to them in our criteria, and should therefore be read in conjunction with such criteria. Please see Ratings Criteria at www.spglobal.com/ratings for further information. Complete ratings information is available to RatingsDirect subscribers at www.capitaliq.com. All ratings affected by this rating action can be found on S&P Global Ratings' public website at www.spglobal.com/ratings.

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Reply Testimony of
James M. Coyne and Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 2500

June 4, 2024

EXHIBIT 2500 – REPLY TESTIMONY – RETURN ON EQUITY

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I. INTRODUCTION AND SUMMARY

Q. Mr. Coyne, please state your name, affiliation, and business address.

A. My name is James M. Coyne. I am a Senior Vice President at Concentric Energy Advisors, Inc. ("Concentric"). My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. Ms. Nelson, please state your name, affiliation, and business address.

A. My name is Jennifer E. Nelson. I am an Assistant Vice President at Concentric. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. Are you the same James M. Coyne and Jennifer E. Nelson who filed Direct Testimony in this proceeding?

A. Yes. We filed Direct Testimony on behalf of Northwest Natural Gas Company dba NW Natural ("NW Natural" or "the Company") regarding the cost of capital (NW Natural/400, Coyne-Nelson).

Q. What is the purpose of your Reply Testimony?

A. The purpose of our Reply Testimony is to respond to the following intervenor witnesses (collectively, "Intervenor Witnesses") as their testimonies relate to the Company's Return on Equity ("ROE") and capital structure:

- Mr. Matt Muldoon, who testifies on behalf of the Oregon Public Utilities Commission ("Commission") Staff;
- Mr. Bradley G. Mullins, who testifies on behalf of the Alliance of Western Energy Consumers ("AWEC");

- Mr. Brad Cebulko, who testifies on behalf of the Coalition of Communities of Color, Climate Solutions, Verde, Columbia Riverkeeper, Oregon Environmental Council. Community Energy Project, and Sierra Club ("Coalition"); and
- Mr. Bob Jenks, who testifies on behalf of the Oregon Citizens' Utility Board ("CUB").

Positions not addressed in our Reply Testimony should not be inferred as agreement with those positions.

Q. How is the remainder of your Reply Testimony organized?

A. The balance of our Reply Testimony is organized as follows:

- Section II provides a summary of our recommendations and our response to the Intervenor Witnesses' positions and cost of capital recommendations;
- Section III addresses trends in authorized ROEs and capital market conditions;
- Section IV responds to the Intervenor Witnesses' capital structure recommendations;
- Section V responds to Staff Witness Muldoon;
- Section VI responds to AWEC Witness Mullins;
- Section VII summarizes our updated ROE analyses that incorporates market data through the end of April 2024; and
- Section VIII summarizes our conclusions and recommendations.

II. SUMMARY OF REPLY TESTIMONY

Q. Please summarize your recommendations presented in your Direct Testimony.

A. In our Direct Testimony, we concluded that a reasonable ROE range for NW Natural is 9.80 percent to 10.40 percent that was developed by using a combination of models and alternative input assumptions.[1] Within that range, we recommended an ROE at the midpoint of the range, or 10.10 percent. Our ROE recommendation is based on the results from the Discounted Cash Flow ("DCF") model, the Bond Yield Plus Risk Premium method ("Risk Premium"), the Capital Asset Pricing Model ("CAPM"), and the Expected Earnings approach, as the use of multiple models enables a more robust evaluation of investors' return requirements and is consistent with industry and investor practice.

Our recommendation also considered the Company's capital expenditure program, the risks associated with electrification and energy transition, and NW Natural's significantly smaller size relative to a group of proxy companies to assist with determining the appropriate ROE. To be clear, however, our recommendation did not include an explicit ROE adjustment to account for these risk factors. Therefore, as our updated analysis further demonstrates, 10.10 percent is a conservative estimate of the Company's cost of equity.

[1] NW Natural/400, Coyne-Nelson/4-5.

As to the Company's requested capital structure, consistent with our recommendation in Direct Testimony, we continue to support NW Natural's requested capital structure of 50.00 percent common equity and 50.00 percent long-term debt as reasonable.

Q. Please summarize the results of your updated ROE analyses.

A. As discussed below in Section VII, applying updated market data through the end of April 2024 to the same estimation models described in our Direct Testimony produces an updated recommended range of 10.10 percent to 10.60 percent for our Gas Proxy Group, with a midpoint of 10.35 percent. Thus, our 10.10 percent ROE recommendation now reflects the bottom of our recommended range, providing further support as to the conservative nature of our recommendation.

Q. Based on your updated ROE analyses, do you change your ROE recommendation in this proceeding?

A. No. We continue to recommend 10.10 percent as a reasonable and conservative estimate of the Company's cost of equity.

Q. Please now summarize the ROE and capital structure recommendations made by the Intervenor Witnesses.

A. Staff Witness Muldoon recommends an ROE range of 8.9 percent to 9.3 percent; however, he does not make an ROE point estimate in this proceeding, which Staff

notes "is a departure from its typical practice."[2] Staff accepts the Company's proposed capital structure of 50 percent common equity and 50 percent total debt.[3]

AWEC Witness Mullins recommends the Commission authorize an ROE of 9.20 percent, within a range of 6.35 percent to 9.55 percent, and a capital structure consisting of 48 percent common equity and 52 percent total debt.[4]

Witnesses for CUB and the Coalition do not make specific ROE or capital structure recommendations; instead, they make general comments regarding the ROE.[5] It is important to note that the determination of an appropriate ROE should be grounded in rigorous financial analysis that considers the subject company's relative risk profile. We address CUB's and Coalition's specific comments regarding the ROE later in this section.

Q. What is your response to Staff Witness Muldoon's and AWEC Witness Mullins' ROE recommendations?

A. Staff Witness Muldoon's and AWEC Witness Mullins' recommendations to reduce NW Natural's authorized ROE fail to reflect the higher capital cost environment faced by the Company. Neither witness has provided any evidence that the Company's capital costs have declined or that its risk has declined since its last rate case such that a reduction in the authorized ROE is appropriate. Instead, both Staff Witness Muldoon and AWEC Witness Mullins disregard the effect of higher

[2] Staff/100, Muldoon/17.

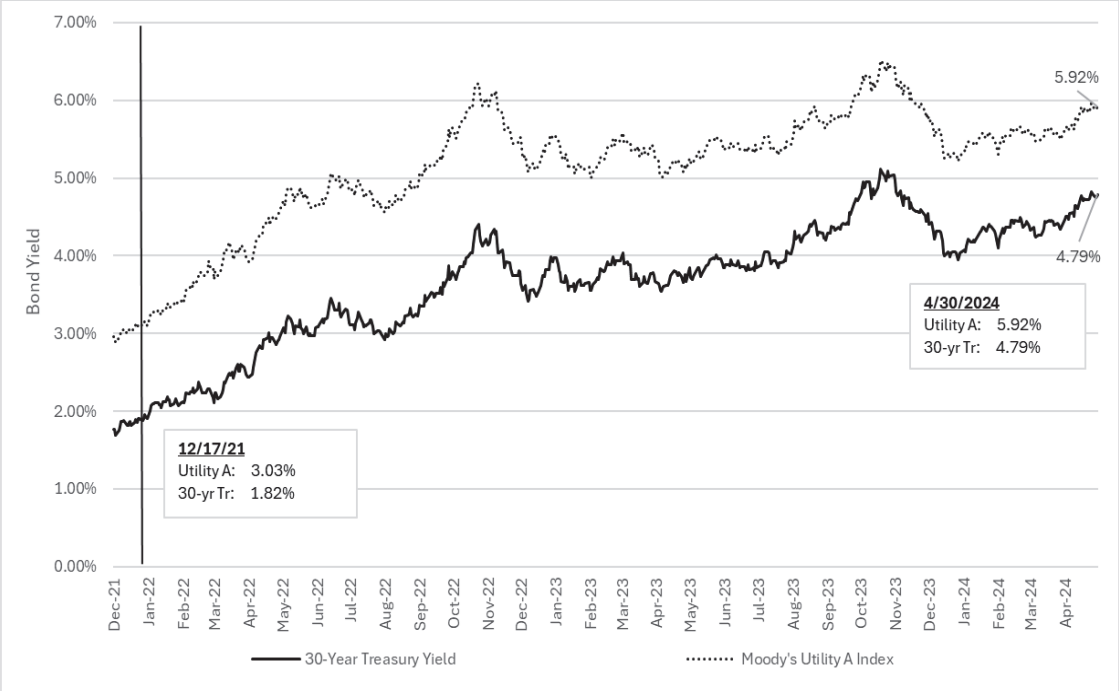
[3] Staff/1600, Pileggi/3.

[4] AWEC/100, Mullins/2.

[5] CUB/100, Jenks/14-15; Coalition/100, Cebulko/13-14; Coalition/200, Apter-Connolly/12-13, 16.

inflation and interest rates on the Company's cost of equity. As shown in Figure 1 below, capital costs have increased by nearly 300 basis points since the Company filed its last rate case on December 17, 2021.

Figure 1: 30-year Treasury Yields and A-Rated Utility Bond Index (December 2021 – April 2024)[6]



Staff Witness Muldoon points to expectations of rate cuts by the Federal Reserve "in the next two years";[7] however, members of the Federal Reserve Board of Governors have been tempering those expectations in recent weeks and emphasizing that they are waiting for sufficient evidence that inflation is moving persistently toward its 2 percent target before considering rate cuts. After its May Federal Open Market Committee ("FOMC") meeting, the Federal Reserve

[6] Source: Bloomberg Professional and Federal Reserve Bank of St. Louis.

[7] Staff/100, Muldoon/35.

emphasized: "The Committee does not expect it will be appropriate to reduce the target range until it has gained greater confidence that inflation is moving sustainably toward 2 percent."[8] At his press conference after the FOMC meeting, Chair Powell reiterated that higher than expected inflation thus far in 2024 is prompting the central bank to hold interest rates higher for longer.[9] Further, he stated that "inflation is still too high, further progress in bringing it down is not assured, and the path forward is uncertain."[10] In short, inflation remains elevated and the timing and magnitude of any interest rate cuts by the Federal Reserve is uncertain.

Q. How do the Staff's and AWEC's ROE recommendations compare to recently authorized returns for other gas utilities?

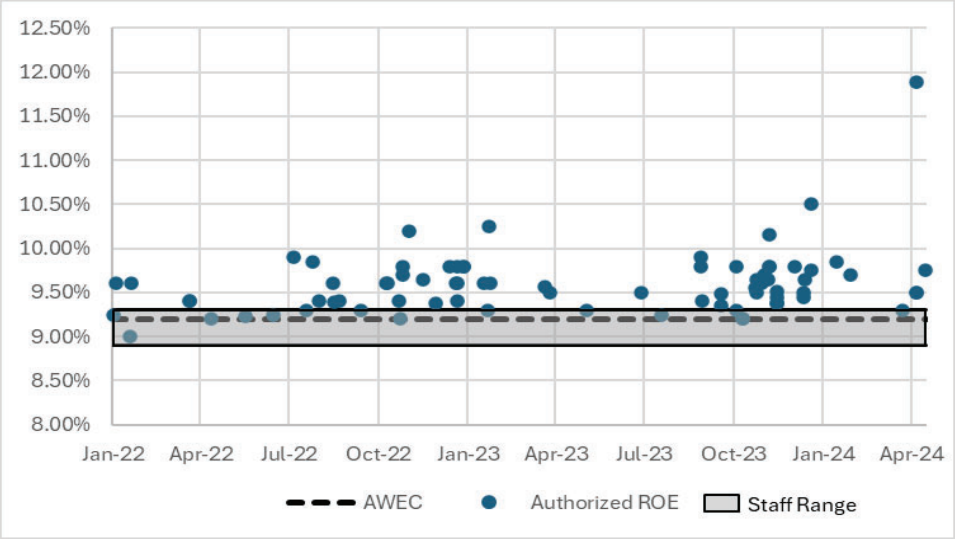
A. As shown in Figure 2 below, Staff's and AWEC's ROE recommendations are at the bottom end of the range of ROEs recently authorized for other natural gas utilities. In fact, an ROE of 9.3 percent (the high end of Staff's recommended range), or lower, is in the bottom 12 percent of ROEs authorized between January 2022 and April 2024.

[8] Federal Reserve Board of Governors Press Release, *Federal Reserve issues FOMC Statement* (May 1, 2024) (accessible at https://www.federalreserve.gov/newsevents/pressreleases/monetary20240501a.htm).

[9] Transcript of Chair Powell's Press Conference at 3 (May 1, 2024) (accessible at https://www.federalreserve.gov/mediacenter/files/FOMCpresconf20240501.pdf).

[10] *Id*. at 1.

Figure 2: Authorized Natural Gas Utility ROEs (2022-2024)[11]



The average authorized ROE for natural gas utilities decided in 2024 is 9.93 percent, which is well above Staff's and AWEC's recommendations but within our recommended range filed in our Direct Testimony. Moreover, the average authorized equity ratio for natural gas utilities in 2024 is 52.35 percent, more than 200 basis points higher than the Company's request in this proceeding. Multiplying the average authorized ROE in 2024 with the average authorized equity ratio in 2024 produces an average authorized weighted common equity rate of 5.20 percent, which is higher than the Company's requested weighted common equity rate of 5.05 percent that is based on our 10.10 percent ROE and 50 percent equity ratio. In other words, the Company's request is *below* the average weighted common equity cost authorized for natural gas utilities in 2024, which demonstrates the reasonableness of our 10.10 percent ROE recommendation.

[11] Source: Regulatory Research Associates.

Staff's and AWEC's recommendations simply would not provide a return that is comparable to returns available to enterprises having corresponding risk (i.e., other natural gas utilities), and thus are inconsistent with the *Hope* and *Bluefield* standards that require a risk comparable return.

Q. How would the investment community perceive Staff's and AWEC's ROE and capital structure recommendations?

A. The investment community would likely perceive a reduction in the authorized ROE and a more leveraged capital structure adversely, particularly during a period of rising capital costs and market uncertainty. The Commission has consistently found a 50/50 capital structure to be balanced for Oregon's regulated utilities, and a departure from that finding would likely be perceived as introducing unpredictability in Oregon's regulatory environment, thereby increasing the Company's risk.

Emphasizing the importance of a constructive outcome in this proceeding, on April 19, 2024, S&P revised NW Natural's outlook from "Negative" to "Stable." S&P explained that the upward revision in its outlook assumes that the Company will generate sufficient cash flows to earn its authorized ROE, which depends on a constructive outcome in this proceeding.

> The stable outlook on NWNG reflects our base-case assumption that NWNG will generate sufficient cash flows to maintain appropriate consolidated financial measures for the current rating, including FFO to debt of 15%-18% through 2026. The stable outlook also reflects our expectation of strong operating performance and effective management of regulatory risk.[12]

S&P noted that the Company's earned ROE has "been modestly weaker than its authorized ROE"[13] over recent years. Reducing both its authorized ROE and equity ratio would constrain NW Natural's ability to maintain its credit metrics within S&P expectations.

Q. Does Staff acknowledge that NW Natural's credit metrics are under pressure?

A. Yes. At Staff/100, Muldoon/35, Staff acknowledges that the Company's credit ratings are "under pressure based on financial metrics." Staff further observes the importance of the regulatory environment in the rating agencies' credit assessments.

Q. CUB Witness Jenks recommends that the Commission "reduce the ROE to the lowest that is allowable" as a means of mitigating rate shock.[14] What is your response?

A. As noted earlier, CUB has not performed an independent analysis to estimate the appropriate ROE or the range of ROEs that is "reasonable." Therefore, his

[12] S&P Global Ratings, *Research Update: Northwest Natural Holding Co. Downgraded to 'A'; Outlook Negative; Subsidiary Ratings Affirmed, Outlook to Stable* at 1 (Apr. 19, 2024).

[13] S&P Global Ratings, *Research Update: Northwest Natural Holding Co. Downgraded to 'A'; Outlook Negative; Subsidiary Ratings Affirmed, Outlook to Stable* at 2 (Apr. 19, 2024).

[14] CUB/100, Jenks/12, 15.

recommendation has limited value. To the extent that CUB believes that a reduction in the Company's current authorized ROE would reflect investors' "lowest allowable" ROE given the significantly higher interest rate environment, we disagree. CUB's position that an increase in the authorized ROE is not "reasonable" due to the level of the Company's rate request[15] suggests that the ROE is discretionary, and that investors' return requirements are dependent upon a company's revenue requirement. Neither of these assumptions is reasonable. As explained in Section III, the return is part of the cost of service and utilities are entitled by law to receive a fair rate of return sufficient to attract needed capital at reasonable rates. The level of a utility's rate request, or its revenue requirement, is not a factor that affects the cost of equity; therefore, it should have no bearing on the ROE determined in this proceeding.

As discussed earlier, the ROE models show that the cost of equity has risen. Our 10.10 percent ROE recommendation now falls at the bottom of our recommended range based on our analyses that have been updated for more recent data through the end of April 2024.

[15] CUB/100, Jenks/14.

Q. Coalition Witness Cebulko asserts that the Company is "seeking a higher return on equity due to the risk of decarbonization policies."[16] Is his characterization of your ROE recommendation correct?

A. No, it is not. As noted earlier, our ROE recommendation does not include a premium due to decarbonization risk, or any of the Company's other risk factors. The recommended range reflects our four-model average using various combinations of inputs, and 10.10 percent reflected the midpoint of the range using market data as of September 29, 2023. As discussed earlier, 10.10 percent now reflects the low end of the range using data as of April 30, 2024.

Although we have identified certain business risks that distinguish NW Natural from its peers, our recommendation reflects the return NW Natural must offer to equity investors to attract capital, as estimated by reference to the proxy group average.

III. TRENDS IN AUTHORIZED ROES AND CAPITAL MARKET CONDITIONS

Q. Staff asserts that we are not in a rising interest rate environment and points to trends in interest rates and authorized ROEs over the last 30 years as support for its position.[17] What is your response?

A. Staff appears to believe that investors are ignoring the significant increase in capital costs over the last two years simply because interest rates and ROEs have fallen from their levels 30 years ago. If so, that premise is misguided.

[16] Coalition/100, Cebulko/17.

[17] Staff/100, Muldoon/35.

Capital costs are at their highest levels in nearly 15 years. To deny NW Natural a compensatory return that appropriately recovers its capital costs, as is required by *Hope*[18] and *Bluefield*,[19] would be contradictory to the foundational principles of the regulatory compact. Although Staff and CUB appear to suggest otherwise,[20] the recovery of capital costs, including the ROE, is not discretionary. The cost of equity is a cost faced by the Company just like any other component in the Company's cost of service, including the cost of debt, O&M costs, taxes, and depreciation expense.

Failure to allow the Company to sufficiently recover its capital costs has real consequences not just for the Company but for customers as well. Customers require safe and reliable service, and NW Natural's ability to meet its obligation to serve requires continuous access to the debt and equity markets in all market environments. To the extent that the Company is viewed as having a less predictable opportunity to sufficiently recover its capital costs, investors will choose less risky investment alternatives that provide better return opportunities, leaving the Company with fewer funding alternatives at higher costs. In the end, customers would be harmed through higher capital costs and/or less capital available to invest in the infrastructure required to maintain safe and reliable service.

[18] *Fed. Power Comm'n v. Hope Nat. Gas Co.*, 320 US 591 (1944).

[19] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 US 679 (1923).

[20] Staff/100, Muldoon/12-13; CUB/100, Jenks/12, 15.

Contrary to Staff's position, Figure 1 shown in Section II above illustrates the significantly higher capital cost environment faced by the Company. Since the Company filed its last rate case in December 2021, the 30-year Treasury yield has increased by nearly 300 basis points from 1.82 percent to 4.79 percent. Moody's A-rated Utility Bond Index increased almost 290 basis points from 3.03 percent to 5.92 percent. These bond yield levels reflect investors' current expectations and incorporate the market's expectations of FOMC actions.

Although Staff refers to expectations that the Federal Reserve will lower interest rates, those expectations have recently been tempered by persistent elevated inflation. The Federal Reserve has signaled its intent to keep interest rates "sufficiently restrictive" until they have confidence that inflation is moving toward the 2 percent target.[21] Federal Reserve officials have adjusted their expectations for future rate cuts and the timing and pace of any future rate change is highly uncertain.[22]

Q. Is Staff's depiction of recent authorized ROEs and interest rates accurate?

A. No. Staff's chart on page Muldoon/36 is more than two years old and omits authorized ROEs and Treasury bond yields since January 2022. To suggest that ROEs and interest rates have trended downward while omitting more than two

[21] Transcript of Chair Powell's Press Conference at 6.

[22] See, e.g., Federal Reserve Governor Michelle W. Bowman, *Brief Remarks on the Economy and Monetary Policy* at the Massachusetts Bankers Association Annual Convention (May 3, 2024) (available at https://www.federalreserve.gov/newsevents/speech/bowman20240503a.htm); Reuters News, "Fed's Barr: Inflation data 'disappointing,' tight policy needs more time," (May 20, 2024) (available at https://www.reuters.com/markets/us/feds-barr-inflation-data-disappointing-tight-policy-needs-more-time-2024-05-20/).

years of recent data showing otherwise is disingenuous. As noted earlier, Staff's and AWEC's recommendations are at the bottom end of ROEs recently authorized for other natural gas utilities, with the average authorized ROE for natural gas utilities in 2024 standing at 9.93 percent as of April 30, 2024.

Q. Why are authorized ROEs in other jurisdictions relevant?

A. As explained in our Direct Testimony, authorized ROEs in other jurisdictions are a significant part of the market information that investors consider when evaluating their investment alternatives. Therefore, they are a measure of returns available to other natural gas utilities, consistent with the *Hope* and *Bluefield* decisions. The level of authorized ROE also provides a signal to investors about the level of regulatory support that a company can expect with regard to its ability to compete for capital and to ensure its financial integrity. An insufficient ROE is an impediment to the Company's ability to attract capital and invest in the infrastructure necessary to provide safe, reliable service to its customers. As explained earlier, our 10.10 percent ROE recommendation, taken together with NW Natural's requested capital structure, is *below* the weighted common equity rate authorized for natural gas utilities on average thus far in 2024, and is therefore conservative.

IV. CAPITAL STRUCTURE

Q. Does Staff support the Company's proposed capital structure?

A. Yes, Staff accepts the Company's proposed capital structure that consists of 50 percent common equity and 50 percent long-term debt.[23]

[23] Staff/1600, Pileggi/3.

Q. Please now summarize AWEC's capital structure recommendation.

A. AWEC Witness Mullins recommends a capital structure of 48 percent common equity and 52 percent long-term debt based on NW Natural's actual capital structure expected at the beginning of the rate-effective period.[24] As discussed below, the Company's proposed capital structure is reasonable and should be approved.

Q. Is the Company's proposed capital structure reasonable?

A. Yes. As explained by Company Witness Wilson, the Company targets a capital structure consisting of 50 percent common equity and 50 percent long-term debt over the long-term, which allows it to access capital at reasonable terms.[25] The Commission has determined that a 50/50 capital structure is reasonable and balanced for Oregon utilities for at least a decade or more. Specifically, in its recent order for Pacificorp, the Commission stated:

> We find that a more balanced capital structure serves to reduce the cost of equity to customers, without jeopardizing the financial integrity of the company. We find that a capital structure of 50 percent equity achieves that balance.[26]

Importantly, the capital structure adopted by the Commission in this proceeding will need to support the Company's financial integrity and capital needs to meet its obligation to serve on a going forward basis. For that reason, a forward-looking perspective of the debt and equity required to provide customers with safe

[24] AWEC/100, Mullins/2, 15.

[25] NW Natural/2400, Wilson.

[26] *In re PacifiCorp Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 at 22-25 (Dec. 18, 2020).

and reliable service is a reasonable approach that is consistent with utility financing practices.

Q. Before responding directly to AWEC Witness Mullins' capital structure recommendation, please explain the factors utilities generally consider in developing a target capital structure.

A. Companies (including subsidiary companies) are financed based on the specific risks and funding requirements associated with their unique individual operations. Capital structure management is dynamic and complex because it must satisfy multiple objectives subject to multiple constraints. It is therefore important to understand utility financing practices, including the principles and constraints that drive utility financing decisions, and how those practices are reflected in the cost of capital. As explained below, utility financing practices reflect the nature of regulation and utilities' investments made under the regulatory compact.

In many respects, the nature of regulation determines the nature of utility assets, and how they are financed. In exchange for the obligation to serve, equity investors expect utilities to have a reasonable opportunity to earn a risk-comparable return on prudent investments over the life of the investments. It is the nature of regulation, therefore, that enables utilities to finance large, essentially irreversible, investments that are recovered over decades. Moreover, because the obligation to serve must be fulfilled regardless of capital market conditions, utility capital structures (and the financial strength they support) are established to ensure capital access not only during normal markets, but when markets are constrained as well. When markets are constrained, only those utilities with

sufficient financial strength can attract capital at reasonable terms to the benefit of customers. That financial strength provides utilities with critical financing flexibility. Utilizing a capital structure for ratemaking purposes that relies more heavily on debt, as AWEC Witness Mullins proposes, increases the risk of refinancing maturing obligations during less accommodating market environments at higher costs. Financing flexibility, therefore, has a cost. As Moody's explains:

> Liquidity and access to financing are of particular importance in this sector. Utility assets can often have a very long useful life – 30, 40 or even 60 years is not uncommon, as well as high price tags…Utilities are among the largest debt issuers in the corporate universe and typically require consistent access to the capital markets to assure adequate sources of funding and to maintain financial flexibility.[27]

The requirement to access capital markets in all market conditions contrasts with the financial needs of other entities without the legal obligation to serve. Because of that obligation, the financial flexibility required to access both long-term capital and short-term liquidity is critical for utilities' ability to continually attract capital to meet the obligation to serve. Unregulated companies can adjust the timing and amount of major capital expenditures to align with economic cycles and defer investments to better match market conditions, whereas utilities have limited options to do so. Reduced financial flexibility, therefore, must be compensated for by ensuring utilities have sufficient financial strength to provide safe and reliable service to customers at all times.

[27] Moody's Investor Service, Rating Methodology: Regulated Electric and Gas Utilities at 25 (Jun. 23, 2017).

Q. Why is AWEC Witness Mullins' recommendation to set the ratemaking capital structure based on the Company's actual capital ratios at a single point in time inappropriate?

A. As noted earlier, capital structure management is dynamic and complex in which utilities must balance multiple objectives with multiple constraints. As Company Witness Wilson explains, NW Natural's actual capital structure fluctuates due to the seasonality of earnings, the timing of capital investments and financings, and the Company's ability to access the market.[28] This is true for all utilities, as debt and equity issuances are lumpy, and the timing of these issuances often do not coincide perfectly to match the ratemaking capital structure authorized by the regulator. Measuring the capital components using a snapshot as of a specific date as AWEC Witness Mullins recommends may result in a skewed interpretation due to the specific circumstances of a particular period. For example, a utility may issue debt to ensure liquidity during constrained capital market environments or take advantage of a lower-priced market window, which may not reflect the utility's long-term capital structure objectives.

Q. Is NW Natural's test year capital structure skewed by period-specific circumstances that do not reflect its longer-term capital structure objectives?

A. Yes. As Company Witness Wilson explains, in 2023, NW Natural pulled forward its 2024 long-term debt needs into 2023 to take advantage of the inversion in the

[28] NW Natural/2400, Wilson/4-5.

yield curve that made borrowing short-term commercial paper more expensive than long-term debt. Further, the Company determined that, given the consistent rise in interest rates through 2022 and 2023, it would be beneficial to mitigate interest rate risk of future issuances. This was also a period that followed a volatile gas price market in the winter of 2022 and doing so ensured sufficient liquidity for the utility through the winter 2023.[29] Customers benefitted from the Company's actions by locking in lower debt costs than they would have otherwise faced and ensuring sufficient liquidity during a volatile market environment. The Company should be encouraged to proactively manage its capital needs to customers' benefit even if that results in short term capital structure deviations from the authorized capital structure.

Q. Are there other variables unique to NW Natural's circumstances that affect the timing of its debt and equity issuances?

A. Yes. As a smaller company,[30] NW Natural is more limited in its ability to access the capital markets than larger companies. As Company Witness Wilson explains, the Company accesses the debt market episodically and receives equity contributions on a regular schedule from the parent company consistent with its at-the-market program that issues smaller amounts of equity during open trading windows.[31] A larger company will have access to a greater number of potential investors and may have more funding opportunities available to it than a smaller

[29] NW Natural/2400, Wilson/6.

[30] See, e.g., NW Natural/410.

[31] NW Natural/2400, Wilson/4-5.

company like NW Natural has. This places an additional constraint the Company must manage when determining an optimal capital funding plan, recognizing that an "optimal" capital structure balances many objectives and constraints that change with the market.

Q. Does Staff acknowledge the dynamic nature of a utility's actual capital at a point in time?

A. Yes, it has. Staff Witness Pileggi acknowledges that capital structure "fluctuations are expected as issuances, redemptions, and maturations on financial instruments are not in perfect sync nor is it always beneficial for the company to maintain a perfectly uniform capital structure."[32]

Q. How does AWEC Witness Mullins' proposed 48 percent equity ratio compare to other natural gas utilities?

A. AWEC Witness Mullins' proposed capital structure is significantly more leveraged than is typical for other natural gas utilities, which would increase NW Natural's financial risk. One approach to evaluating the reasonableness of the Company's proposed capital structure is to review how other regulated natural gas operating utilities generally finance their operations, recognizing that each utility has unique capital needs. As shown in NW Natural/411, Coyne-Nelson/1, five of the six natural gas utility proxy companies have an average equity ratio of at least 54.48 percent, or higher, between 2020 and 2022[33], which is nearly 450 basis points above the

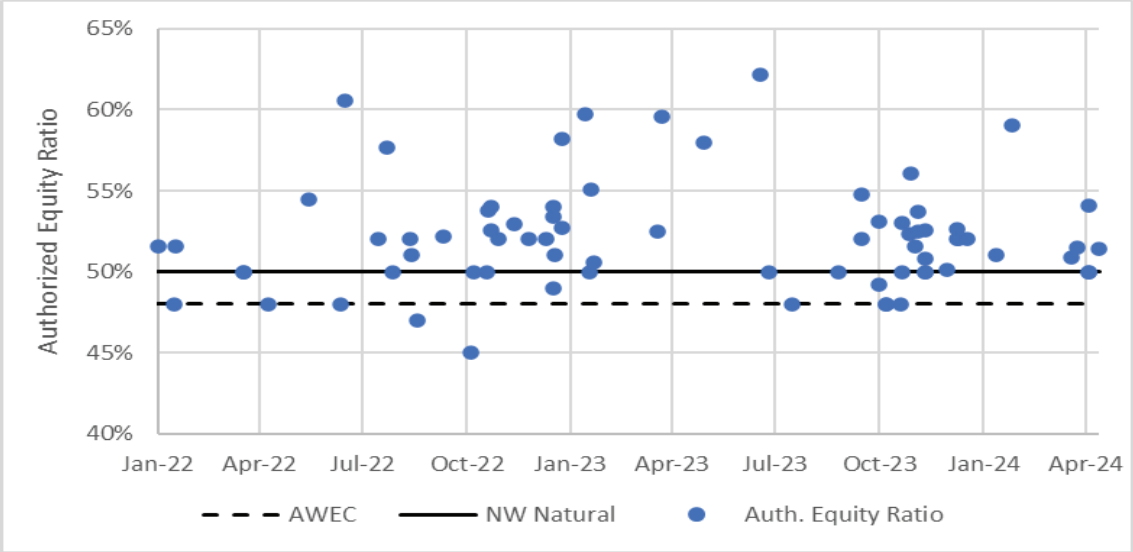
[32] Staff/1600, Pileggi/2-3.

[33] Actual capital structure data for 2023 is not yet available for all utilities in the Gas Proxy Group as of the time of filing.

Company's requested equity ratio. Only one company, Southwest Gas Company, has an equity ratio near AWEC Witness Mullins' recommendation.

For another perspective, we also reviewed the common equity ratios authorized by regulatory commissions across the U.S. over the last three years. As shown in Figure 3 below, AWEC Witness Mullins' equity ratio proposal is significantly below those recently authorized for other natural gas utilities. In fact, more than 89 percent of decisions since January 2022 authorized an equity ratio above AWEC Witness Mullins' 48 percent recommendation.

Figure 3: Authorized Equity Ratio – Natural Gas Utilities (2022-2024)[34]



Further, Figure 3 also demonstrates the reasonableness, if not conservative nature, of the Company's requested 50 percent equity ratio; nearly 68 percent of

[34] Investor-supplied capital components only. Arkansas, Florida, Indiana, and Michigan include non-investor supplied capital (e.g., customer deposits, Accumulated Deferred Income Taxes, etc.) in the ratemaking capital structure, rendering the authorized equity ratios as a percentage of total capital that is reported by Regulatory Research Associates in these jurisdictions not comparable to the equity ratios authorized in Oregon that includes only investor-supplied capital.

natural gas utilities were authorized an equity ratio above NW Natural's requested 50 percent since 2022. AWEC Witness Mullins has not demonstrated that NW Natural's requested capital structure of 50 percent equity and 50 percent long-term debt is unreasonable or deviates substantially from sound utility practice; therefore, the Company's request should be approved.

Q. What is your response to AWEC Witness Mullins' accusation that the Company is "diluting its own capital structure in order to finance water company acquisition at the holding company level"[35]?

A. Despite providing no evidence to support his belief, AWEC Witness Mullins' position appears to be inappropriately focused on the debt issued by NW Natural's parent rather than NW Natural itself, the entity at issue in this proceeding. NW Natural is its own legal entity that issues its own debt, and, as Company Witness Wilson explains, the funds from those issuances are not used to acquire water utilities.[36]

V. RESPONSE TO STAFF WITNESS MULDOON

Q. Please summarize Staff's recommendation in this proceeding.

A. Staff recommends an ROE range of 8.90 percent to 9.30 percent. Although Staff states that it does not have an ROE point estimate, Staff observes that the mean of its recommended range is 9.10 percent.[37] Staff's recommended ROE range is developed using two Three-Stage DCF analyses. Staff also performs a Single

[35] AWEC/100, Mullins/15.

[36] NW Natural/2400, Wilson/7.

[37] Staff/100, Muldoon/17.

Stage DCF analysis and a CAPM analysis to check the reasonableness of its Three-Stage DCF results.

Q. Do you have concerns with Staff's recommended ROE range?

A. Yes, we do. As Staff recognizes, the authorized ROE and capital structure in this proceeding will directly affect the Company's ability to attract capital at a reasonable cost.[38] As discussed earlier, even the top end of Staff's recommended ROE range, 9.3 percent, would reflect a reduction from the current authorized ROE, making it more difficult for the Company to maintain credit coverage metrics within the ranges necessary to retain its credit rating that enable it to access long term debt at a reasonable cost. S&P has noted NW Natural's difficulty in earning its authorized return and weakening financial profile; Staff's recommendation would further exacerbate this condition.

Q. What are the primary areas of disagreement between you and Staff?

A. The primary areas of disagreement with Staff's ROE analyses include (1) its primary reliance on a single model, (2) its exclusion of New Jersey Resources and inclusion of Northwest Natural Holding Company in the proxy group, (3) the application of its Three-Stage (or "Multi-Stage") and Single Stage (or "Constant Growth") DCF analyses, and (4) the application of its CAPM analysis, in particular Staff's market risk premium ("MRP").

Lastly, we note that there are errors and inconsistencies in Staff's analyses that diminish the reliability of its analyses and the ROE recommendation upon

[38] Staff/100, Muldoon/35.

which it is based. Should Staff provide corrections, we reserve the right to review these corrections and respond accordingly. We discuss these in more detail below.

A. Primary Reliance on a Single Model

Q. Does Staff's recommendation rely primarily on a single methodology?

A. Yes. Although Staff considers a Single Stage DCF analysis and a CAPM analysis as a "check" on the reasonableness of his Multi-Stage DCF analysis, its recommended ROE range is based on the results of its two Multi-Stage DCF analyses.

Q. Why is it important to consider the results of multiple methodologies when estimating the cost of equity?

A. As explained in our Direct Testimony, each model is based on a set of limiting assumptions, and changes in market conditions will affect each model differently. Further, each model provides a unique perspective on investors' return requirements. Therefore, it is important to consider a variety of methodologies to ensure that the cost of equity estimate is not biased by a particular model's results that may be unduly influenced by certain inputs or market data at the time. Although we understand that the Commission in the past has given weight to the Multi-Stage DCF approach, relying on multiple methodologies is consistent with investor practice and enables a more robust and reliable ROE estimate.

B. Proxy Group Composition

Q. Is Staff's Peer Utility screening process used to develop his Proxy Group clear and consistent?

A. No, it is not. There are several inconsistencies in Staff's testimony and its exhibits that make it difficult to understand its Peer Utility screening process. For example, there are several references to electric utilities or regulated electric operations; however, Exhibit Staff/101, Muldoon/2 includes only natural gas utilities in the group of companies initially considered and does not appear to consider electric utilities. Additionally, in Exhibit Staff/101, Muldoon/2, Staff appears to have excluded natural gas utilities that have a Beta coefficient greater than 1.0, however, this screening criterion is not listed in the seven screening criteria described at Staff/100, Muldoon/19. Further, Staff's screening criterion #2 explains that the proxy companies must have a positive dividend growth rate forecast by Value Line; however, as explained in more detail later, Exhibit Staff/101, Muldoon/3, two companies - NiSource Inc. and Southwest Gas Holdings – are projected to have a decline in dividends between 2025 and 2026.[39]

Q. Does Staff's analysis correctly reflect your Gas Utility proxy group?

A. No. As described in our Direct Testimony, our Gas Utility proxy group consisted of six companies and excluded NW Natural's parent company due to the circular logic that would occur. NW Natural/403, Coyne-Nelson/1 shows that NW Natural is

[39] For Southwest Gas Holdings, this is more clearly seen in the Excel version of Staff's exhibits when shown to three decimal places.

excluded from the Company's proxy group. However, Exhibit Staff/101, Muldoon/2 includes NW Natural's parent company in its depiction of our proxy group.

Q. Do you agree with Staff's exclusion of New Jersey Resources Corporation from the proxy group?

A. No. Staff explains that New Jersey Resources Corporation was excluded "based on how much of its operational cash flows are regulated and that the credit rating coverage for the Company was withdrawn by Moody's and Standard & Poor's." [40] However, there is no reference to a cash flow evaluation in Staff's description of the selection criteria on Staff/100, Muldoon/19 or in Staff/101, Muldoon/2.

In terms of the credit rating, New Jersey Resources Corporation's primary subsidiary, New Jersey Natural Gas ("NJNG"), is rated A1 by Moody's Investors Service. New Jersey Natural Gas's regulated gas distribution operations reflected more than 61 percent of New Jersey Resources Corporation's operating income and more than 65 percent of its assets. As such, investors likely give significant weight to New Jersey Natural Gas's credit rating in assessing New Jersey Resources Corporation's risk. For example, Fitch Ratings currently rates New Jersey Natural Gas as "A-", but does not rate the publicly traded parent New Jersey Resources Corporation, and notes "NJNG is the primary driver of earnings for the parent New Jersey Resources (NJR), so the rating also takes into consideration NJR's relatively higher risk, albeit conservatively managed, non-utility businesses, comprising Federal Energy Regulatory Commission regulated midstream assets,

[40] Staff/100, Muldoon/19.

a portfolio of commercial and residential solar projects, energy trading and energy services business."[41]

For these reasons, it is reasonable to use New Jersey Natural Gas's A1 rating by Moody's as a proxy for the credit rating of New Jersey Resources Corporation and New Jersey Resources should be included in the proxy group.

Q. Staff does not think an alternative Combined Proxy Group that supplements the Natural Gas Proxy Group by adding combination electric and natural gas utilities with substantive natural gas operations is "informative for the Commission."[42] What is your response?

A. We disagree. First, Staff appears to agree that the relatively small group of publicly traded natural gas companies is a potential issue that may need to be addressed in the future and it suggests that it will perform "sensitivity modeling" on a group of water utilities in its rebuttal testimony for the Commission's consideration.[43] As explained in our Direct Testimony, to address that concern, we added 11 companies classified as electric utilities by Value Line that had operating income from natural gas distribution operations of at least 15 percent on average over the last three years. Therefore, we include only those combination electric and natural gas utilities that have a meaningful proportion of natural gas operations. Although Staff seems concerned with "divergent risk profiles" between electric and natural

[41] Fitch Ratings, *Rating Report: New Jersey Natural Gas Company* (Apr. 29, 2024) (available at https://www.fitchratings.com/research/corporate-finance/new-jersey-natural-gas-company-29-04-2024).

[42] Staff/100, Muldoon/21.

[43] Staff/100, Muldoon/20-21.

gas utilities,[44] screening utilities for meaningful proportions of natural gas operations mitigates this concern, and we rely on the Natural Gas Proxy Group in reaching our recommendations.

C. Application of the DCF Model

1. Multi-Stage DCF Model

Q. Does the Multi-Stage DCF model produce reasonable estimates of the Company's cost of equity?

A. No, it does not. Due to the model's limiting assumptions that may be questionable at the current time, Staff's Multi-Stage DCF approaches produce results that range from 8.20 percent to 9.13 percent.[45] The low end of this range is 50 basis points below the lowest ROE authorized for a natural gas utility in more than 40 years, and the high end of this range is in the bottom 2 percent of ROEs authorized for natural gas utilities since 1980. Even looking to a more recent time period, Staff's highest Multi-Stage DCF result of 9.13 percent is in the bottom 1 percent of ROEs authorized for natural gas utilities since 2022. In fact, there is only one decision in the last three years in which a natural gas utility was authorized an ROE of 9.13 percent or lower. This is why it is important to rely on multiple methodologies, rather than a single model. The *Hope* and *Bluefield* decisions require the authorized return to be comparable to other returns available to investors in companies with similar risk. The Multi-Stage DCF results violate this standard.

[44] NW Natural/2513, Coyne-Nelson, Staff Response to NWN Data Request No. 20.

[45] Staff/103, Muldoon/1.

Q. What are your concerns with the Multi-Stage DCF analyses employed by Staff?

A. Although we also consider a Multi-Stage DCF analysis given the Commission's past preference for the model, we recognize the model's limitations and therefore do not rely on it exclusively. Additionally, we have identified certain issues with Staff's Multi-Stage DCF analysis. Specifically, we are concerned with (1) the accuracy of, and Staff's method for, calculating the current stock price, (2) the accuracy of the dividend forecasts, and (3) the terminal value.

Q. Please describe your concerns with Staff's development of its average stock price.

A. First, it appears that Staff may not have entered the correct prices for the first trading day of each month. Staff/100, Muldoon/28 at line 6, states the analysis uses the "average of closing prices for each utility from the first trading day in February 2024, March 2024 and April 2024." However, as shown in Figure 4 below, (see also Exhibit NW Natural/2508, Coyne-Nelson), the prices from Yahoo! Finance for each utility from the first trading day of the corresponding months do not match Staff's prices on Exhibit Staff/101, Muldoon/4. In fact, except for NW Natural Holdings, the three-day average prices reported by Yahoo! Finance are lower than what Staff used in its analysis. The result of Staff's errors is that the dividend yield in Staff's DCF analysis is lower, biasing its DCF estimate downward.

Figure 4: Stock Prices Reported by Staff vs. Yahoo! Finance[46]

			STAFF/101, Muldoon/4 - AS FILED				Spot Closing Price from Yahoo! Finance			
			Yahoo Finance Q1 2024				Yahoo Finance Q1 2024			
			$ Stock Closing Price			*3-Day*	$ Stock Closing Price			*3-Day*
			1st Trading Day of Month			*Avg $*	1st Trading Day of Month			*Avg $*
	Abbreviated		Feb.	Mar.	Apr.	*Stock*	Feb.	Mar.	Apr.	*Stock*
#	Utility	Ticker	2/1/2023	3/1/2024	4/1/2024	*Price*	2/1/2024	3/1/2024	4/1/2024	*Price*
1	Atmos	ATO	112.91	118.87	116.23	116.00	115.79	112.73	117.85	115.46
3	New Jersey	NJR	41.61	42.91	42.78	42.43	41.46	41.77	42.66	41.96
4	NiSource	NI	26.06	27.66	27.19	26.97	26.35	26.13	27.48	26.65
5	NW Natural	NWN	36.74	37.22	26.41	33.46	37.03	36.93	37.12	37.03
6	ONE Gas	OGS	59.60	64.53	63.72	62.62	61.90	59.48	63.62	61.67
8	Southwest Gas	SWX	68.15	76.13	74.54	72.94	59.93	69.61	75.58	68.37
9	Spire	SR	59.32	61.37	59.34	60.01	59.27	59.61	60.95	59.94

A bigger concern, however, is Staff's reliance on three spot prices to determine the dividend yield. Reliance on a very small sample of spot prices is arbitrary and can be unduly influenced by anomalous trading patterns on a single day, as stock prices can be highly variable due to factors that may be unrelated to the stock's intrinsic value. Simply, there is no evidence that investors would rely on stock prices from three arbitrarily chosen dates at the beginning of the month as being reflective of expectations going forward. A more common and prudent approach is to develop an average price over a longer period as we have done by reviewing averaging periods of 30-, 90-, and 180-trading days. This approach smooths out volatility and mitigates the risk that anomalous data biases the results.

Q. Please describe your concerns with Staff's forecasted dividends used in its Multi-Stage DCF analysis.

A. A foundational assumption of the Multi-Stage DCF model is that a company's dividend grows each year. In fact, as identified in Staff's own proxy screening criteria, companies that have cut their dividend are typically excluded from the

[46] NW Natural/2508, Coyne-Nelson.

proxy group. It is therefore illogical to forecast a dividend cut in the Multi-Stage DCF model. However, Exhibit Staff/101, Muldoon/3 projects a dividend cut in 2026 for NiSource and Southwest Gas Holdings.[47] It is unclear why Staff is forecasting a dividend cut, violating its own screening criteria, as well as the theoretical assumption of the model.

Moreover, in a Three-Stage DCF model, the transition stage should apply a consistent yearly dividend change to bridge the end of the initial stage to the beginning of the final stage. However, as demonstrated in Exhibit Staff/102, Muldoon/1, the growth in dividends through the transition period is inconsistent. For example, Staff projects that Atmos Corporation's dividend will increase by 24 cents in 2025, 7 cents in 2026, 34 cents in 2027, 38 cents in 2029, 35 cents in 2030 and 37 cents in 2031. These illogical assumptions directly impact the ROE recommendation, rendering Staff's analysis questionable. Unreliable modeling and inputs create unreliable ROE recommendations.

Q. Please describe your concerns with Staff's Price-to-Earnings multiple approach in Model Y.

A. For context, Staff states that the objective of Model Y is to model an approach in which an investor is assumed to hold the stock until it reaches a specific Terminal Value based on an assumed P/E" ratio.[48] Importantly, the model assumes that the Terminal Value that occurs in Year 30 is the goal, and the investor sells.

[47] As noted earlier, the projected decline in the annual dividend in 2026 is more easily seen in Staff's Excel file when the dividends are shown to three decimal places.

[48] Staff/100, Muldoon/26.

To forecast the terminal value within Model Y, Staff multiplies the 2024 current Price-to-Earnings ("P/E") multiple to a forecasted earnings per share ("EPS") in 2054. However, in reviewing Staff's exhibits, it appears that Staff applied the 2025 EPS forecast from Staff/101, Muldoon/3 as the 2024 EPS in Model Y. It is unclear if this is an error or was intentional; however, if Staff is trying to use a forward P/E multiple, then the terminal value EPS used in its calculation should be adjusted accordingly. Additionally, using the current P/E multiple does not consider whether the current P/E ratio is stable and consistent with expectations going forward. It would be more appropriate to apply a long-term P/E multiple to the forecasted EPS.

Q. Staff asserts that "relying on a long-term GDP growth rate" can "overstate [the] required ROE."[49] Do you agree?

A. No, we do not. Despite providing no evidence supporting its position, Staff states that "it is possible that Staff modeling anticipates greater growth than may be realized and so overstates required ROE to attract investors" on the basis that electric demand growth is linked to GDP growth.[50]

GDP is the sum of all private industry and government output in the United States, and its growth rate is an approximate average of the value of those industries. As such, some sectors will grow faster than the average, and some will grow slower. As shown in Exhibit NW Natural/2509, since 1947, the utility sector

[49] Staff/100, Muldoon/31.

[50] Staff/100, Muldoon/31. We recognize Staff may be referring to electric utility sales in error rather than natural gas utility sales.

as a component of GDP has grown at a faster compound annual average rate (6.55 percent) than the overall GDP growth rate (6.37 percent). If anything, the use of a GDP growth rate as the terminal growth rate in the Multi-Stage DCF analysis places a low ceiling on long-term growth and biases the model's ROE estimates downward.

Q. Does your Multi-Stage DCF analysis use an expected GDP growth rate as the terminal growth rate?

A. Yes, we have presented the Multi-Stage DCF model in deference to the Commission's past practice. However, we recognize this limiting assumption in the model and thus have not given exclusive or primary weight to its results. Relying exclusively on this model presents significant model risk in the sense that the cost of equity estimate, and Staff's ROE recommendation, depends substantially on whether GDP growth is an accurate estimate of the proxy group's long-term growth expectations. As discussed above, GDP growth could be a poor measure of utility growth.

Q. Please discuss Staff's application of a Hamada adjustment to the results of their recommended range.

A. Staff applies a Hamada adjustment to its DCF results to normalize differences in the proxy group capital structure and the Company's proposed capital structure in this case. However, the resulting effect on Staff's ROE recommendation is unclear as once again there are inconsistencies between Staff's exhibits and the testimony.

Exhibit Staff/101, Muldoon/4 shows the adjustment as a 12-basis point[51] reduction to the recommended ROE range, while in testimony, Staff/100, Muldoon/34 describes the adjustment as a 24-basis point reduction.

Q. Do you have general concerns over the application of the Hamada adjustment?

A. Yes. A Hamada adjustment is typically reserved for companies that have a materially different capital structure than their peers. In this instance, the Company's capital structure is relatively consistent with industry standards, although it is somewhat more leveraged than the regulated operating companies within the Gas Proxy Group. Furthermore, Staff has already screened its proxy group using a debt leverage screening criterion to ensure the proxy group consists of companies with comparable risk profiles to NW Natural. Incorporating a further Hamada adjustment unnecessarily over weights any perceived differences in financial risk.

The Hamada adjustment has been occasionally used in the rare case in which a company's capital structure is not deemed to be "optimal" or represented by the proxy companies. However, as discussed earlier in Section III above, the determination of an "optimal" capital structure is dynamic and complex and each utility's unique circumstances and financing needs factor into the determination of what is "optimal." A 50/50 capital structure may be "optimal" for NW Natural in the

[51] This is more easily seen in Staff's Excel exhibits when the Hamada adjustment result is shown to two decimal places.

current environment, but it may not be optimal for Atmos Corporation, or any other company. Further, a utility's "optimal" capital structure requires sufficient flexibility for varying market environments. While a 50/50 capital structure may be optimal today, it may not be optimal tomorrow under constrained market circumstances. Applying the Hamada adjustment to all proxy companies based on a debt ratio of 50 percent, therefore, implicitly presumes that this capital structure is "optimal" for all companies, which is a false and misleading conclusion.

Lastly, there are additional inconsistencies in Staff's Hamada adjustment analysis. First, Staff uses an equity risk premium of 4.20 percent, but offers no explanation regarding the basis of this equity risk premium, as it differs from the 5.35 percent equity risk premium applied in its CAPM analysis. Further, the tax rates for Atmos, ONE Gas, and Spire do not match Value Line's 2024 estimated tax rates as cited by Staff. While we have not attempted to reconcile these inconsistencies and their effect on Staff's results, they raise questions as to the reliability of Staff's analysis and its ultimate ROE recommendation.

Q. After your review of Staff's application of the Hamada adjustment, do you believe the results can be relied upon for setting an authorized ROE in this case?

A. No. The application of a Hamada adjustment is inappropriate in this case as the Company's capital structure is not materially different than its peers, nor should it be presumed that all the proxy companies should be financed with the same capital structure as NW Natural. Additionally, there are inconsistencies with Staff's analysis and testimony, rendering the analysis unreliable.

2. Constant Growth DCF Analysis

Q. Does Staff use any alternative ROE methodologies to test the reasonableness of the Multi-Stage DCF model results?

A. Yes. Staff has considered the Constant Growth DCF model and the CAPM analysis to test the reasonableness of its Multi-Stage DCF model results.[52] However, Staff has not placed any weight on the results of these alternative methodologies in establishing its range of results or its ROE recommendation. As noted earlier, each ROE estimation model has its own strengths and shortcomings. When the results of one model cannot be corroborated by the results of alternative models, it is reasonable and appropriate to consider the individual and collective results of multiple methods to establish the return on equity.

Q. Please summarize Staff's position with respect to the Constant Growth DCF model.

A. Staff has performed a Constant Growth DCF analysis to test the reasonableness of its Three-Stage DCF model. As shown in Exhibit Staff/105, Muldoon, Staff's Constant Growth DCF model produces a proxy group average ROE estimate of 7.70 percent for our proxy group and 7.50 percent for Staff's proxy group. However, Staff contends that the Constant Growth DCF model "cannot incorporate known, measurable, and material information about the future usually built into Three-Stage DCF analysis."[53]

[52] Staff/100, Muldoon/17-18, 25.

[53] Staff/100, Muldoon/38.

Q. Does the Three-Stage or Multi-Stage DCF analysis better incorporate "known, measurable, and material information about the future" relative to the Constant Growth DCF analysis?

A. No. Staff's position appears to be that the Three-Stage DCF model is somehow superior, or more accurate, than the Constant Growth or Single Stage DCF model. This is a false premise. There is no basis for Staff's claim that its judgment and input selection regarding the timing and growth of annual dividends over the three stages, the P/E ratio, and Terminal Value is any more "known, measurable, and material information about the future" than the inputs applied in the simpler Constant Growth DCF model. Both Staff's Multi-Stage and Constant Growth DCF analysis rely on the same stock prices and the dividends and growth rates are from Value Line. Therefore, if these inputs are not "known, measurable, or material" enough for the Constant Growth DCF model, then it is curious why Staff relies on them in its Multi-Stage analysis. If anything, Staff's reliance on inputs from a single source (Value Line) exposes it to potential bias, whereas our use of three projected growth rate sources (including Value Line as one of three sources) mitigates the potential for bias from any one source.

Q. Do you have any additional concerns with Staff's Single Stage DCF model?

A. Yes, we do. Staff's unreasonably low results are driven primarily by its use of Value Line's dividend growth rate projections instead of earnings growth rate projections. Further, although Staff attempted to replicate Value Line's methodology for calculating its five-year dividend growth rate, the results do not reconcile with the five-year dividend growth rates Value Line reports for the proxy companies and are

lower, thus biasing Staff's ROE results downward. Inserting the correct dividend growth rate projections from Value Line increases Staff's Single Stage DCF growth rates for both Staff's and our proxy groups by 90 basis points (see Exhibit NW Natural/2510, Coyne-Nelson). While Staff's Constant Growth DCF results are unreasonably low even when corrected, applying Value Line's correct dividend growth rates demonstrates the significant effect Staff's error has on its model results.

Q. Please explain why earnings growth rates are the most appropriate for use in the DCF model.

A. As explained in our Direct Testimony, the DCF model assumes that earnings, dividends, and book value grow at the same constant rate. Further, dividend growth can only be sustained by earnings growth, as earnings are the fundamental determinant of a company's ability to pay dividends. Further, management's strategies regarding dividend policies can be influenced in the short term by other objectives, such as cash flow management practices. Additionally, academic research has found that earnings growth rates are better predictors of stock prices than other measures of growth. In addition to the Carleton and Vander Weide study referenced in our Direct Testimony, a 2002 study in the *Journal of Accounting Research*, examined "the valuation performance of a comprehensive list of value drivers" and found that "forward earnings explain stock prices remarkably well" and

were generally superior to other value drivers analyzed.[54] A 2012 study from the journal *Contemporary Accounting Research* found that the sell-side analysts with the most accurate stock price targets were those whom the researchers found to have more accurate earnings forecasts.[55]

Additionally, Value Line is the only source we are aware of that publishes dividend and book value growth rate projections. The fact that dividend and book value growth rate projections are not widely reported by other sources further supports the conclusion that earnings growth is the most meaningful measure of growth among the investment community. In other words, if investors relied heavily on projections of dividend growth, more sources would offer that data.

Lastly, when providing guidance to investors regarding the overall total return targets in their investor presentations, companies define the return as the sum of the dividend yield and *earnings* growth, not dividend growth.[56] In doing so, they recognize that investors consider earnings growth to be the primary driver of stock values.

[54] Liu, Jing, et al., *Equity Valuation Using Multiples*, JOURNAL OF ACCOUNTING RESEARCH, Vol. 40 No. 1 (Mar. 2002).

[55] Gleason, C.A., et al., *Valuation Model Use and the Price Target Performance of Sell-Side Equity Analysts*, CONTEMPORARY ACCOUNTING RESEARCH.

[56] *See, e.g.*, New Jersey Resources, Shareholder Appreciation Day Investor Presentation at slide 40 (Jun. 23, 2023).

D. CAPM Analysis

Q. As a check on its Multi-Stage DCF model, Staff also develops a CAPM analysis.[57] Please describe that analysis.

A. Staff's CAPM analysis produces an ROE estimate of approximately 9.2 percent for its proxy group, which it claims supports the reasonableness of the "middle to high end" of its Multi-Stage DCF model of 9.3 percent.[58] Staff relies on a spot risk-free rate of 4.555 percent as of April 5, 2024, a market risk premium ("MRP") of 5.35 percent, and Value Line Beta coefficients.[59]

Q. What are your primary concerns with Staff's CAPM analysis?

A. Although Staff only uses the CAPM as a check on its Multi-Stage DCF results, our primary concern is with Staff's market risk premium estimate. While we also disagree with the use of a spot risk-free rate, it is relatively close to our current 30-day average 30-year Treasury yield, so at this time we do not address Staff's risk-free rate.

Q. How does Staff develop its MRP?

A. Staff's 5.35 percent MRP is calculated by taking the difference between Staff's 9.90 percent market return and its 4.555 percent risk free rate.

Q. What is the basis for Staff's 9.90 percent market return estimate?

A. Staff's 9.90 percent market return estimate appears to be based on the return on the S&P 500 between 1993-2023 (i.e., the last 31 years). In response to NWN

[57] Staff/104, Muldoon/1.

[58] Staff/100, Muldoon/17.

[59] Staff/100, Muldoon/23-24; Staff/104, Muldoon/1.

Data Request No. 22[60], Staff states it calculated a market return between 1993 to 2023 of 9.85 percent, which it rounded to 9.90 percent. According to Staff's workpaper provided in NWN DR 22 Attachment A, 9.85 percent appears to reflect the average of Staff's calculation of the arithmetic average annualized price return of the S&P 500 Index, and the arithmetic average annualized total return of the S&P 500 Index.

Q. Is it reasonable or appropriate to rely on the price appreciation return as a measure of investors' expected market return?

A. No. If a historical average market return is to be used, only the total return on the market should be used. The total annual return is the sum of three components: (1) the capital appreciation (or price) return, (2) the income return, and (3) the reinvestment return.[61] As explained by Kroll, for a single month the reinvestment return is zero, but over a longer period of time it is non-zero.[62] Staff's historical annualized price return only includes one of these three components (i.e., the capital appreciation return) and does not include the income return (i.e., return from dividends) or the reinvestment return (i.e., reinvestment of dividend income), and is thus significantly lower than the total return. For the S&P 500 Index companies that pay dividends, investors undoubtedly incorporate the income generated from dividend payments, and the reinvestment of those dividends, into their return calculations and forward-looking market return expectations. Therefore, basing an

[60] NW Natural/2514, Coyne-Nelson.

[61] Kroll, 2023 SBBI Yearbook, at 54.

[62] Kroll, 2023 SBBI Yearbook, at 54.

expected market return solely on the price appreciation return is not reflective of actual investor theory and practice, which biases Staff's market return estimate. The use of the total return is supported by Kroll that calculates its reported historical equity risk premium as the difference between the *total return* on the S&P 500 Index and the income return on long-term government bonds.[63]

Adjusting Staff's CAPM analysis for its 10.83 percent historical arithmetic annualized total market return estimate in NWN DR 22 Attachment A raises its CAPM results by 80 basis points to a range of 9.99 percent to 10.10 percent,[64] which overlaps our recommended ROE range and our point recommendation of 10.10 percent (see Exhibit NW Natural/2511, Coyne-Nelson).

Q. Is the use of a geometric average market return appropriate for estimating the forward-looking market return estimate?

A. No, it is not. Staff recommends at Staff/100, Muldoon/41 that "market returns be calculated based off the historic long-run growth rates of stocks"; in its response to NWN Data Request No. 24[65], Staff clarifies that "[t]he appropriate long-run calculation in this context is the geometric market risk premium." Although Staff does not appear to use the geometric average market return in calculating its 9.90 percent market return, we nonetheless address Staff's position that the geometric

[63] Kroll, 2023 SBBI Yearbook, at 190.

[64] For the reasons discussed below, the entire history of available market return data should be used when relying on a historical market return. Therefore, we do not agree with Staff's 31-year subset of historical market return data. Nonetheless, we apply Staff's historical arithmetic annualized total market return to demonstrate the significant effect that applying the price appreciation return has on Staff's CAPM results.

[65] NW Natural/2515, Coyne-Nelson.

average market return, or market risk premium, is appropriate for the cost of equity estimation purposes.

The arithmetic mean assumes that each observation is independent from another and, therefore, incorporates uncertainty into the calculation of the long-term average. The geometric mean, on the other hand, is backward-looking, equating a beginning value to an ending value. Although geometric averages provide a standardized basis to assess past performance across investments or investment managers, they do not reflect forward-looking uncertainty. Lastly, investment volatility (i.e., risk), is typically measured based on the standard deviation, which is a function of the arithmetic mean, not the geometric mean.

Many financial textbooks and investor publications advise against the use of geometric averages as a basis for a forward-looking estimate of expected returns in the CAPM.[66] For example, Ibbotson explains:

> The geometric average is more appropriate for reporting *past performance*, since it represents the compound average return…The argument for using the arithmetic average is quite straightforward. In looking at projected cash flows, the equity risk premium that should be employed is the equity risk premium that is expected to actually be incurred over the future time periods. The best estimate of the expected value of a variable that has behaved randomly in the past is the average (or arithmetic mean) of its past values.[67]

Dr. Roger Morin adds,

[66] *See, e.g.,* Roger A. Morin, Ph.D., New Regulatory Finance 133-138 (2006); Kroll, 2023 SBBI Yearbook, at 193.

[67] Ibbotson Stocks, Bonds, Bills, and Inflation, 2005 Yearbook, Valuation Edition, at 75 (emphasis added).

> Because valuation is forward looking, the appropriate average is the one that most accurately approximates the expected future rate of return. The best estimate of expected returns over a given future holding period is the arithmetic average. Only arithmetic means are correct for forecasting purposes and for estimating the cost of capital. There is no theoretical or empirical justification for the use of geometric mean rates of returns as a measure of the appropriate discount rate in computing the cost of capital or in computing present values.[68]

Because the cost of equity is forward-looking, if a historical average is used, the arithmetic mean is the correct estimate for use in the CAPM. Contrary to Staff's position, a long-term historical arithmetic average market return is not "extreme."[69]

Q. Do you agree with Staff's use of a 30-year historical period to calculate the market return?

A. No, we do not. Staff seems to be concerned with certain economic periods influencing the expected market return going forward. However, Staff's self-selected historical market return period is subjective in nature and unrepresentative of long-term trends in market data. As explained by Kroll:

> The estimate of the equity risk premium depends on the length of the data series studied. A proper estimate of the equity risk premium requires a data series long enough to give a reliable average without being unduly influenced by very good and very poor short-term returns. When calculated using a long data series, the historical equity risk premium is relatively stable. Furthermore, because an average of the realized equity risk premium is quite volatile when calculated using a short history, using a long series makes it less likely that the analyst can justify any number he or she wants.

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[68] Roger A. Morin, Ph.D., New Regulatory Finance, at 116-117 (2006).

[69] Staff/100, Muldoon/24.

> Some analysts estimate the expected equity risk premium using a shorter, more recent period on the basis that recent events are more likely to be repeated in the near future; furthermore, they believe that the 1920s, 1930s, and 1940s contain too many unusual events. This view is suspect because all periods contain unusual events. Some of the most unusual events of the last 100 years took place quite recently, including the inflation of the late 1970s and early 1980s, the October 1987 stock market crash, … the attacks of September 11, 2001, the global financial crisis of 2008-2009, and most recently, the market crash in the first quarter of 2020 that was precipitated by the spread of the COVID-19 virus.[70]

Whereas Staff suggests that our historical average MRP that is based on data between 1926 to 2022 may be biased because it includes post-World War II "boom time" returns, it also includes nine years of negative returns due to the Great Depression and World War II. Therefore, our long-term historical arithmetic average return includes returns over many economic cycles and interest rate and inflation cycles and is the least biased because we have not arbitrarily selected a subset of return data. This approach is consistent with investor practice and is promoted by Ibbotson. As Dr. Morin explains:

> Because risk premiums based on short time periods can be particularly volatile, changing with capital market conditions, inflationary expectations, and fiscal-monetary forces, they should be ignored. One should rely instead on the long-term results, since periods of such length are long enough to smooth out short-term aberrations, and to encompass several business and interest rate cycles. In their comprehensive study of historical returns, Ibbotson Associates recommend the use of the entire study period in estimating the appropriate market risk premium, so as to minimize subjective judgment and to encompass as many diverse regimes of inflation, interest rate cycles, and economic cycles as possible.[71]

[70] Kroll, 2023 SBBI Yearbook, at 193-194.

[71] Roger A. Morin, Ph.D., New Regulatory Finance at 114 (2006).

Further, our approach does not attempt to guess what types of economic cycles are likely to be repeated[72] since the entire return history available to us is used.

Q. Staff asserts that "expectations should mirror the recent 30-year returns".[73] Do you agree?

A. No. There is no evidence that expectations should mirror a recent 30-year period. Annual market returns are largely random, highly volatile, and driven by a variety of factors. While investors' expectations are influenced by recent history, those expectations can change at a moment's notice as new data arise and events occur. There is no basis to support the position that a 30-year history is any more superior than nearly 100 years of history that accounts for economic booms and busts, very high and very low inflation, wars, and times of government and monetary policy intervention.

Despite substantial volatility in annual returns year to year, the long-term arithmetic average historical market return is surprisingly stable. Interestingly, the average arithmetic market return between 1926 and 1994 was 12.17 percent, exactly equal to the average market return between 1926 and 2023 that adds 30

[72] Staff/100, Muldoon/24.

[73] Staff/100, Muldoon/25.

more years of history.[74] This evidence contradicts Staff's premise that stock returns experienced in the last 30 years have been lower.

Q. Staff Witness Muldoon suggests that your Market Return is "an extreme input" and "inflated".[75] Do you agree?

A. No. First, as a preliminary matter, we developed several CAPM estimates, applying various combinations of risk-free rates (both current and projected), Beta coefficients from two sources, and MRP estimates using both a historical average and forward-looking market return estimates. The low end of our recommended ROE range is based on our four-model average that relies on the most conservative CAPM inputs (the historical average MRP and projected risk-free rate). The high end of our recommended ROE range is based on our four-model average that relies on a blend of our forward-looking and historical MRP and current interest rates. In other words, we have given more weight to the most conservative MRP estimate in developing our recommended ROE range. To be clear, the market return presented in our Direct Testimony assumes market returns of 13.31 percent and 11.59 percent.

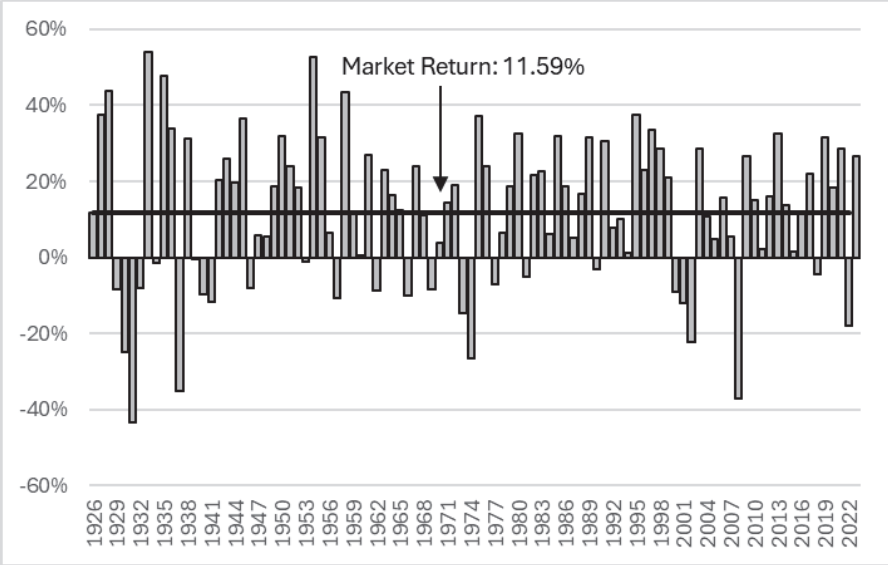
To assess the reasonableness of a market return of 11.59 percent and higher, we reviewed the 98 annual market returns between 1926 and 2023 and compared how often a market return of 11.59 percent and higher occurred. As

[74] We note that in 2024 Kroll revised its methodology for calculating the long-term average market return and market risk premium. Under Kroll's revised methodology, the average arithmetic average total market return from 1926 to 2023 is 12.04 percent, highly consistent with the 12.17 percent long-term average noted here that uses Kroll's previous methodology.

[75] Staff/100, Muldoon/23.

shown in Figure 5 below (see also Exhibit NW Natural/2512), a market return of 11.59 percent and higher has occurred in 55 of 98 years, or more than 56 percent of the time. In the last 30 years (the period that Staff believes is relevant), a market return of 11.59 percent and higher has occurred in 18 of 30 years, or 60 percent of the time. By these measures, a market return of 11.59 percent and higher is reasonable.

Figure 5: Frequency of Annual Market Returns (1926 – 2023)[76]



VI. RESPONSE TO AWEC WITNESS MULLINS

Q. Please summarize AWEC Witness Mullins' ROE recommendation.

A. AWEC Witness Mullins recommends an ROE of 9.2 percent based solely on a CAPM analysis.[77] Although we agree with AWEC Witness Mullins that the CAPM is a methodology widely used by investors and should be considered by the

[76] Source: Kroll, 2023 Classic Yearbook, Appendix A-1; Kroll Cost of Capital Navigator.

[77] AWEC/100, Mullins/2.

Commission, we disagree with his input selection and his sole reliance on this single model. We continue to recommend the use of multiple methodologies as the basis of a sound cost of equity estimate.

Q. AWEC Witness Mullins asserts that market conditions do not justify an increase in the Company's ROE.[78] What is your response?

A. AWEC Witness Mullins is incorrect. As shown in Figure 1 above in Section II, capital costs have increased nearly 300 basis points since the Company filed its last rate case in December 2021. A 70-basis point increase in the authorized ROE would incorporate less than 25 percent of the overall increase in capital costs. The evidence does not support that the cost of equity has fallen, justifying a lower authorized ROE.

Q. AWEC Witness Mullins asserts that your "high" ROE estimate is due to "underweighting" the Multi-Stage DCF analysis and "overweighting" the CAPM modeling results.[79] Is he correct?

A. No, he is not. AWEC Witness Mullins misunderstands the development of our recommendation. To be clear, our recommended ROE range is based on an average of four model results in which each model (DCF, CAPM, Risk Premium, and Expected Earnings) is given equal weight. We do present multiple CAPM approaches, however, and the four-model average that is the basis of the low and high ends of our recommended range reflects just one of those CAPM approaches

[78] AWEC/100 Mullins/5.

[79] AWEC/100, Mullins/6.

in the average. As explained earlier, the low end of our recommended ROE range is based on our four-model average that relies on the CAPM approach that uses the most conservative CAPM inputs (the historical average MRP and projected risk-free rate). The high end of our recommended ROE range is based on our four-model average that relies on the CAPM approach that uses a blend of our forward-looking and historical MRP and current interest rates.

Q. What is your response to AWEC Witness Mullins' comparison of Beta coefficients reported by Value Line, Bloomberg, and Yahoo! Finance?

A. On AWEC/100, Mullins/8, AWEC Witness Mullins presents Beta coefficients for the gas proxy companies from three sources: Value Line, Bloomberg, and Yahoo! Finance. No witness in this proceeding supports the use of Yahoo! Finance Beta coefficients, including AWEC Witness Mullins.[80] As AWEC Witness Mullins observes, the difference in the timing of the return calculation (i.e., weekly vs. monthly) can have a considerable effect on the Beta coefficient. By their nature, Beta coefficients calculated using monthly returns rather than weekly returns do not capture inter-month return volatility and thus tend to be lower. As AWEC Witness Mullins acknowledges in response to NW Natural's Data Request 7 to AWEC, this is not unique to utility stocks. The fact that monthly Beta coefficients are lower than weekly Beta coefficients, however, should not be interpreted as an indication of lower risk. As discussed below, Beta coefficients calculated using

[80] See NW Natural/2516, Coyne-Nelson, AWEC's Response to NW Natural Data Request No. 7.

monthly returns obscure relevant intermonth volatility, leading to flawed and misleading conclusions.

Consider, for example, stock prices for two utilities – Utility A and Utility B – over a 60-trading day period (approximately three calendar months), illustrated in Figure 6 below. Both utilities start trading at a price of $100 per share. Both utilities report a total return of 11.69 percent at the end of three months. At the end of every month (the 20th trading day), both stocks have the same price. However, Utility B's stock is clearly more volatile (and therefore riskier) than Utility A's. If the Beta coefficient for Utility B was calculated using monthly returns, it would not capture intermonth stock price volatility and Utility B's Beta coefficient would be the same as Utility A's. On the other hand, if the Beta coefficients are calculated using weekly returns (every five trading days), Utility B's Beta coefficient would be higher than Utility A's, all else equal, better reflecting its higher volatility.

Figure 6: Illustrative Example of Weekly vs. Monthly Stock Volatility

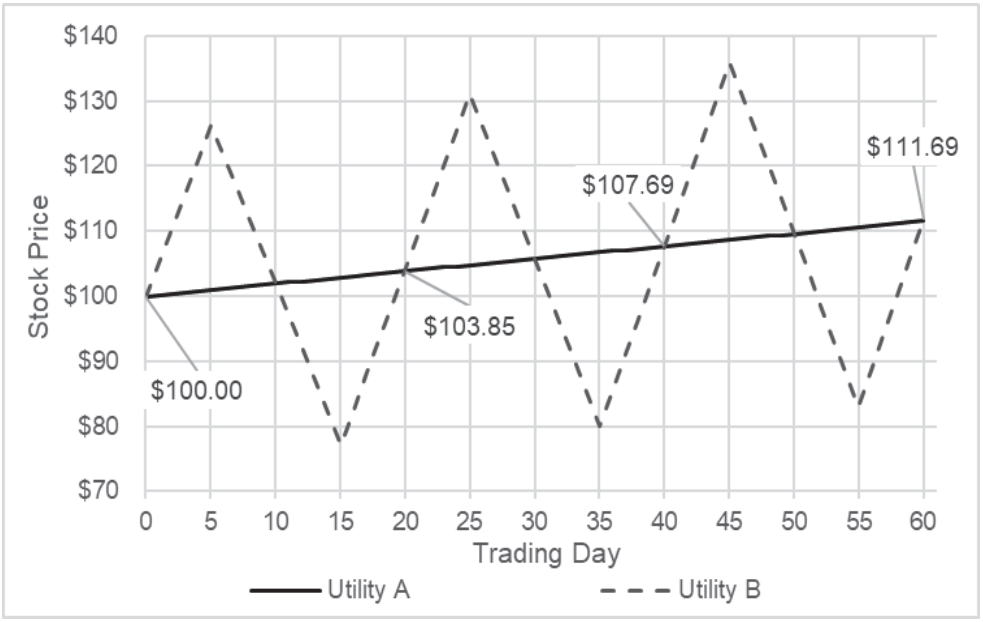


Figure 6 above demonstrates why it is inappropriate to compare Beta coefficients calculated using weekly returns with those that are calculated using monthly returns. Calculating Beta coefficients using weekly return data as Value Line and Bloomberg do is a reasonable and balanced approach to measuring stock volatility.

Q. AWEC Witness Mullins asserts that you "selectively ignore the poorly performing stocks" in your forward-looking market return estimate.[81] Is he correct?

A. No. AWEC Witness Mullins mischaracterizes our response to AWEC DR 44, which is provided as AWEC/102, Mullins/8. We do not exclude S&P 500 companies that were "operating at a loss" or "had a negative price to earnings ratio" such that "it was impossible to produce a meaningful growth figure from the data" as AWEC Witness Mullins asserts.[82] As shown in Exhibit NW Natural/407, pages 2-15, the analysis includes companies with a zero percent growth rate or negative growth rates, so we have included companies with poor growth rates. The companies without a growth rate are those for which there are no analyst consensus earnings growth rates, whatever the reason (the reasons are not disclosed). As explained in our response to AWEC DR 44, a market-cap growth weighted rate simply cannot be developed with companies that lack a growth rate estimate. Because the

[81] AWEC/100, Mullins/10.

[82] AWEC/100, Mullins/10.

purpose is to develop a market-cap weighted dividend yield and growth rate, we can only use companies for which earnings growth rates are published.

Q. AWEC Witness Mullins suggests that applying the Constant Growth DCF model to the S&P 500 is contrary to the Commission's preference for the Multi-Stage DCF model.[83] What is your response?

A. AWEC Witness Mullins fails to understand the fundamental difference in applying the Constant Growth DCF model to develop a cost of equity estimate for a single utility, or group of utilities, versus developing an estimate for the S&P 500 Index as the expected market return component in the CAPM. The FERC addressed the difference in Opinion 531-B, explaining:

> The rationale for incorporating a long-term growth rate estimate in conducting a two-step DCF analysis of a specific group of utilities does not necessarily apply when conducting a DCF study of the companies in the S&P 500. That is because the S&P 500 is regularly updated to include only companies with high market capitalization. While an individual company cannot be expected to sustain high short-term growth rates in perpetuity, the same cannot be said for a stock index like the S&P 500 that is regularly updated to contain only companies with high market capitalization, and the record in this proceeding does not indicate that the growth rate of the S&P 500 stock index is unsustainable.[84]

Q. What is your response to AWEC Witness Mullins' position that the use of a historical MRP is "not an accepted method"?[85]

A. AWEC Witness Mullins is incorrect. As discussed in response to Staff, when properly developed and when current and expected market conditions are largely

[83] AWEC/100, Mullins/10.

[84] 149 FERC ¶ 61,032, Opinion No. 531-B at ¶113.

[85] AWEC/100, Mullins/10-11.

consistent with historical data, a historical MRP is an acceptable estimate of the forward-looking MRP. That said, we agree that cost of equity is forward looking, and thus forward-looking inputs should be given weight; therefore, we have used both a historical and a forward-looking MRP in our CAPM analysis.

We agree that equity risk premiums change over time and with market conditions[86] and that is the underlying premise of our Bond Yield Plus Risk Premium analysis. This analysis shows that the equity risk premium is inversely related to changes in interest rates. As interest rates increase, the equity risk premium decreases and vice versa.

Q. What is your response to AWEC Witness Mullins' position that your Risk Premium analysis does not "have merit"?[87]

A. AWEC Witness Mullins misunderstands the analysis. First, as previously noted, the analysis addresses AWEC Witness Mullins' concern that the equity risk premium moves in response to market conditions. Further, the analysis does not "merely [peg] a utility's ROE at a certain number of basis points above the risk-free interest rate" nor does it "assume that a gas utility should earn a premium equal to 5.95 percent above the risk free rate, regardless of any other circumstances in equity or debt markets" as AWEC suggests.[88] As shown in Exhibit NW Natural/408, the estimated risk premium resulting from the analysis changes with the bond yield. At a yield of 4.42 percent, the implied risk premium is 5.95 percent;

[86] AWEC/100, Mullins/11.

[87] AWEC/100, Mullins/12.

[88] AWEC/100, Mullins/12.

however, at bond yields of 4.18 percent and 3.80 percent, the risk premium is 6.09 percent and 6.30 percent, respectively.

Q. What is your response to AWEC Witness Mullins' reference to MRP estimates from Kroll and NYU professor Dr. Aswath Damodaran?[89]

A. As explained in more detail below, we do not agree that the MRP estimates reported by Kroll and Dr. Damodaran are reasonable estimates in the current circumstances. Further, because these estimates rely on subjective judgment and inputs that are at odds with those routinely used in utility regulatory proceedings, it is difficult to consider these sources as "unbiased."

Turning first to Kroll's estimates, one concern is that Kroll recommends using the 20-year Treasury bond yield as the risk-free rate, rather than the 30-year Treasury bond yield that is typically used in utility regulatory proceedings, which affects the MRP. A second and more important concern is that it is not clear that Kroll develops its expected MRP in relation to its risk-free rate. The MRP is calculated as the difference between the expected market return and risk-free rate; therefore, it is a function of the expected market return and risk-free rate at a point in time. In other words, the MRP and risk-free rate are not independent of each other; rather, they are interrelated, and should be developed concurrently. In fact,

[89] AWEC/100, Mullins/12-13.

and as explained earlier, academic studies have shown that the two are inversely related.[90] As the risk-free rate decreases, the MRP increases and vice versa.

However, as shown in Figure 7 below, Kroll's recommended Equity Risk Premium does not appear to move in relation to the risk-free rate, contrary to AWEC Witness Mullins' concern that the equity risk premium moves with changes in the market environment. Whereas academic studies indicate that the two lines should move in opposite directions, Figure 7 below shows that they do not.

Figure 7: Kroll Recommended Equity Risk Premium and Risk-Free Rate (2008-2024)[91]

[90] See, e.g., Robert S. Harris and Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, at 63-70 (Summer 1992); Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management, at 33-45 (Spring 1985); and Farris M. Maddox, Donna T. Pippert, and Rodney N. Sullivan, *An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry*, Financial Management, at 89-95 (Autumn 1995).

[91] Source: Kroll Cost of Capital Navigator.

The conclusion that there is no clear relationship between Kroll's variables supported by statistical analysis. To assess whether there is a relationship, we performed a linear regression in which Kroll's recommended Equity Risk Premium was the dependent variable and the recommended risk-free rate was the independent variable. The R-square was 0.30 percent, which indicates that Kroll's risk-free rate explains only 0.30 percent of the change in the Equity Risk Premium. This runs counter to the fundamental principle that the MRP is a function of the risk-free rate, as noted earlier. Moreover, the slope coefficient is positive which indicates that the two are positively related (*i.e.*, move in the same direction) and not inversely related (*i.e.*, move in opposite directions), again contrary to academic literature. However, the slope coefficient was not statistically significant, which means there is little confidence in the statistical results. This is not to suggest that Kroll is not a valid or credible source of data. Rather, it suggests that the usefulness of Kroll's Equity Risk Premium recommendation at the current time is questionable given that it runs counter to academic and financial theory.

Turning to Dr. Damodaran's implied equity risk premium model, the model is complex and highly dependent upon the inputs and assumptions in that model. In our opinion, it is important to understand all the inputs and assumptions into Dr. Damodaran's model to vet the reasonableness of those assumptions before relying substantially on the outputs of that model. Our simplified understanding of Dr. Damodaran's model is that it applies a two-stage DCF analysis for the S&P 500 Index in which the first stage of growth relies on an estimate of analysts' projected earnings growth for the S&P 500 Index for the first five years, and a terminal stage

of growth equal to the 10-year Treasury bond yield for years six through perpetuity. We also understand that Dr. Damodaran assumes the 10-year Treasury bond yield as the discount rate. The assumed terminal growth rate is an especially critical input because it represents a significant portion of the terminal value and the ultimate valuation. In our opinion, Dr. Damodaran's assumptions are not reasonable or consistent with the Cost of Equity analyses that we see typically applied in utility regulatory proceedings. These concerns should not be construed to suggest we are criticizing Dr. Damodaran's model for academic purposes; rather, Dr. Damodaran's Implied Equity Risk Premium model is not useful for utility ratemaking purposes given its underlying assumptions. Moreover, we do not believe that it is appropriate to simply accept the inputs and assumptions used in Dr. Damodaran's Implied Equity Risk Premium model for Cost of Equity applications.

Q. Have observed MRP been consistent with the MRP estimates produced by Dr. Damodaran's implied equity risk premia model?

A. No, they have not. As shown in Figure 8 below, Dr. Damodaran's annual Implied Equity Risk Premium estimates have been far removed from actual observed MRP in recent years. In fact, on average, the actual MRP has been more than double the estimates from Dr. Damodaran's model.

Figure 8: Dr. Damodaran's Annual Implied Equity Risk Premium vs. Observed MRP[92]

Year	Dr. Damodaran's Implied Equity Risk Premium	Actual MRP
2010	5.20%	10.81%
2011	6.01%	-1.71%
2012	5.78%	13.54%
2013	4.96%	29.51%
2014	5.78%	10.28%
2015	6.12%	-1.09%
2016	5.69%	9.66%
2017	5.08%	19.16%
2018	5.96%	-7.20%
2019	5.20%	28.94%
2020	4.72%	16.98%
2021	4.24%	26.98%
2022	5.94%	-20.72%
2023	4.60%	22.44%
Average	**5.38%**	**11.26%**

Q. AWEC Witness Mullins points to your Multi-Stage DCF results as evidence to support his conclusion that show that "while interest rates might have risen, the cost of equity for NW Natural has not."[93] What is your response?

A. There are several logical flaws with AWEC Witness Mullins' conclusions. First, it is important to remember that interest rates are not a direct input into the DCF model; therefore, the DCF model does not directly measure how changes in interest rates affect the cost of equity. Second, AWEC does not compare how the Multi-Stage DCF results have changed as interest rates have risen. As shown in

[92] Sources: https://pages.stern.nyu.edu/~adamodar/New_Home_Page/home.htm; Kroll, 2023 SBBI Yearbook, Appendix A-1 and A-7, Kroll Cost of Capital Navigator.

[93] AWEC/100, Mullins/13.

Exhibit NW Natural/2501, Coyne-Nelson/2 compared to Exhibit NW Natural/403, Coyne-Nelson/2, our Gas Proxy Group mean Multi-Stage DCF results increased 22-basis points between September 2023 and April 2024. As another comparison, Staff's ROE range that is based on its Multi-Stage DCF models increased from its analysis filed in the Company's last rate case, further supporting the conclusion that the Cost of Equity has increased.[94]

VII. UPDATED ANALYSIS

Q. Have you updated your analysis to incorporate more recent data?

A. Yes, we updated our analyses to incorporate market data through April 30, 2024, using the methodologies described in our Direct Testimony.[95] As shown in Exhibit NW Natural/2501, Coyne-Nelson/1, the recommended range produced by our models for the Gas Proxy Group increased to 10.10 percent to 10.60 percent. However, at this time, we maintain our point ROE recommendation of 10.10 percent.

Q. Has your proxy group changed from your Direct Testimony?

A. We have not changed our Gas Proxy Group, which is the proxy group on which our recommendation relies. In our Direct Testimony, we also presented a Combined Proxy Group as an alternative given the relatively small number of publicly traded natural gas utilities. One company, MGE Energy, no longer meets

[94] In Staff's testimony filed in Docket No. UG 435, Staff's ROE ranged from 8.6 percent to 9.2 percent, which indicates that the low end of Staff's range increased by 30 basis points and the high end of its range has increased by 10 basis points in this proceeding. See Docket No. UG 435, Staff/100, Muldoon/22 Table 6.

[95] See Exhibits NW Natural/2501 to NW Natural/2507, Coyne-Nelson.

our screening criteria because it does not have positive earnings growth rates from two sources. Therefore, we removed MGE Energy from the Combined Proxy Group. However, our recommendation is ultimately based on the results from the Gas Proxy Group and, therefore, removing MGE Energy does not affect our recommendation.

VIII. SUMMARY AND CONCLUSIONS

Q. Please summarize your conclusions and recommendations.

A. Based on our updated analyses using market data as of April 30, 2024, we maintain our conclusion that 10.10 percent is a reasonable, if not conservative, estimate of NW Natural's cost of equity. Additionally, we continue to support NW Natural's requested capital structure of 50.00 percent common equity and 50.00 percent long-term debt as reasonable relative to the range of capital structures for the operating companies held by the proxy group companies, as well as recently authorized capital structures for natural gas utilities. As explained in our testimony, the Company's requested ROE and equity ratio combined produce a weighted equity return that is below the average authorized ROE and equity ratio for natural gas utilities in 2024.

Neither Staff's nor AWEC's analyses support a reduction in the Company's cost of equity, as their analyses apply flawed inputs that bias their recommendations downward. Their recommendations cannot be reconciled with the fact that capital costs have risen nearly 300 basis points since the Company filed its last rate case. Lastly, neither has considered the adverse effects on the Company's credit profile that their recommendations would cause.

Q. Does this conclude your Reply Testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibits of
James M. Coyne and Jennifer E. Nelson

RETURN ON EQUITY
EXHIBITS 2501 – 2516

June 4, 2024

EXHIBITS 2501-2516 – RETURN ON EQUITY

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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James M. Coyne and Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 2501

June 4, 2024

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SUMMARY OF ROE MODEL RANGES AND ROE RECOMMENDATION

	[1]	[2]	[3]
Gas Proxy Group Mean	4-model Average (Blended MRP CAPM)	4-model Average (Hist MRP CAPM)	Midpoint of Range
Results at Current Interest Rates	10.60%	10.23%	
Results at Projected Interest Rates	10.48%	10.05%	
Range of Results (Min & Max, rounded)	**10.10%**	**10.60%**	**10.35%**

Combined Proxy Group Mean	4-model Average (Blended MRP CAPM)	4-model Average (Hist MRP CAPM)	Midpoint of Range
Results at Current Interest Rates	10.86%	10.46%	
Results at Projected Interest Rates	10.73%	10.29%	
Range of Results (Min & Max, rounded)	**10.30%**	**10.90%**	**10.60%**

Point ROE Recommendation	**10.35%**

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COMBINED DCF, CAPM, RISK PREMIUM AND EXPECTED EARNINGS RESULTS - CURRENT INTEREST RATES

Company	Ticker	Mean Constant DCF	Mean Multi-Stage DCF	CAPM BB Beta (Blended MRP)	CAPM VL Beta (Blended MRP)	CAPM BB Beta (Historical MRP)	CAPM VL Beta (Historical MRP)	AVG DCF	AVG CAPM (Blended MRP)	AVG CAPM (Historical MRP)	Risk Premium	Expected Earnings	4-model Average (Blend CAPM)	4-model Average (Hist MRP CAPM)
Atmos Energy Corporation	ATO	10.06%	7.88%	11.94%	12.14%	10.53%	10.69%	8.97%	12.04%	10.61%	10.42%	10.30%	10.43%	10.08%
New Jersey Resources Corporation	NJR	9.56%	8.89%	12.16%	13.02%	10.70%	11.40%	9.22%	12.59%	11.05%	10.42%	13.40%	11.41%	11.02%
NiSource Inc.	NI	11.71%	9.54%	12.40%	12.58%	10.90%	11.05%	10.63%	12.49%	10.97%	10.42%	11.26%	11.20%	10.82%
ONE Gas, Inc.	OGS	8.93%	8.89%	11.99%	12.14%	10.57%	10.69%	8.91%	12.06%	10.63%	10.42%	8.73%	10.03%	9.67%
Southwest Gas Holding	SWX	10.43%	8.84%	12.69%	12.58%	11.13%	11.05%	9.64%	12.63%	11.09%	10.42%	7.63%	10.08%	9.70%
Spire, Inc.	SR	10.46%	10.10%	12.24%	12.14%	10.77%	10.69%	10.28%	12.19%	10.73%	10.42%	8.86%	10.44%	10.07%
Ameren Corporation	AEE	9.71%	8.67%	12.04%	12.58%	10.61%	11.05%	9.19%	12.31%	10.83%	10.50%	10.27%	10.57%	10.20%
Avista Corporation	AVA	11.80%	11.01%	12.02%	13.02%	10.59%	11.40%	11.41%	12.52%	11.00%	10.50%	8.65%	10.77%	10.39%
Black Hills Corporation	BKH	7.07%	8.91%	13.67%	13.91%	11.93%	12.12%	7.99%	13.79%	12.02%	10.50%	8.73%	10.25%	9.81%
CenterPoint Energy, Inc.	CNP	9.85%	7.89%	14.41%	14.80%	12.52%	12.84%	8.87%	14.60%	12.68%	10.50%	9.77%	10.93%	10.45%
CMS Energy Corporation	CMS	10.26%	8.70%	12.03%	12.14%	10.60%	10.69%	9.48%	12.08%	10.64%	10.50%	13.25%	11.33%	10.97%
DTE Energy Company	DTE	9.09%	8.61%	12.87%	13.47%	11.28%	11.76%	8.85%	13.17%	11.52%	10.50%	12.79%	11.33%	10.91%
NorthWestern Energy Group, Inc.	NWE	9.61%	9.98%	13.42%	13.02%	11.73%	11.40%	9.80%	13.22%	11.57%	10.50%	8.14%	10.41%	10.00%
Public Service Enterprise Group Inc.	PEG	9.03%	8.59%	13.01%	13.02%	11.40%	11.40%	8.81%	13.02%	11.40%	10.50%	12.79%	11.28%	10.87%
Southern Company	SO	10.06%	9.08%	12.51%	13.02%	10.99%	11.40%	9.57%	12.77%	11.20%	10.50%	14.70%	11.89%	11.49%
Wisconsin Energy Corporation	WEC	10.15%	9.20%	11.86%	12.14%	10.47%	10.69%	9.68%	12.00%	10.58%	10.50%	13.16%	11.33%	10.98%
GAS PROXY GROUP MEAN		10.19%	9.02%	12.24%	12.43%	10.77%	10.93%	9.61%	12.33%	10.85%	10.42%	10.03%	10.60%	10.23%
COMBINED PROXY GROUP MEAN		9.86%	9.05%	12.58%	12.86%	11.05%	11.27%	9.46%	12.72%	11.16%	10.47%	10.78%	10.86%	10.46%

COMBINED DCF, CAPM, RISK PREMIUM AND EXPECTED EARNINGS RESULTS - PROJECTED INTEREST RATES

Company		Mean Constant DCF	Mean Multi-Stage DCF	CAPM BB Beta (Blended MRP)	CAPM VL Beta (Blended MRP)	CAPM BB Beta (Historical MRP)	CAPM VL Beta (Historical MRP)	AVG DCF	AVG CAPM (Blended MRP)	AVG CAPM (Historical MRP)	Risk Premium	Expected Earnings	4-model Average (Blend CAPM)	4-model Average (Hist MRP CAPM)
Atmos Energy Corporation	ATO	10.06%	7.88%	11.65%	11.85%	10.04%	10.20%	8.97%	11.75%	10.12%	10.21%	10.30%	10.31%	9.90%
New Jersey Resources Corporation	NJR	9.56%	8.89%	11.87%	12.77%	10.21%	10.91%	9.22%	12.32%	10.56%	10.21%	13.40%	11.29%	10.85%
NiSource Inc.	NI	11.71%	9.54%	12.13%	12.31%	10.41%	10.55%	10.63%	12.22%	10.48%	10.21%	11.26%	11.08%	10.65%
ONE Gas, Inc.	OGS	8.93%	8.89%	11.70%	11.85%	10.08%	10.20%	8.91%	11.78%	10.14%	10.21%	8.73%	9.91%	9.50%
Southwest Gas Holding	SWX	10.43%	8.84%	12.42%	12.31%	10.64%	10.55%	9.64%	12.37%	10.60%	10.21%	7.63%	9.96%	9.52%
Spire, Inc.	SR	10.46%	10.10%	11.96%	11.85%	10.28%	10.20%	10.28%	11.91%	10.24%	10.21%	8.86%	10.32%	9.90%
Ameren Corporation	AEE	9.71%	8.67%	11.76%	12.31%	10.12%	10.55%	9.19%	12.03%	10.34%	10.27%	10.27%	10.44%	10.02%
Avista Corporation	AVA	11.80%	11.01%	11.74%	12.77%	10.10%	10.91%	11.41%	12.25%	10.51%	10.27%	8.65%	10.65%	10.21%
Black Hills Corporation	BKH	7.07%	8.91%	13.43%	13.68%	11.43%	11.63%	7.99%	13.55%	11.53%	10.27%	8.73%	10.13%	9.63%
CenterPoint Energy, Inc.	CNP	9.85%	7.89%	14.19%	14.59%	12.03%	12.35%	8.87%	14.39%	12.19%	10.27%	9.77%	10.82%	10.27%
CMS Energy Corporation	CMS	10.26%	8.70%	11.74%	11.85%	10.11%	10.20%	9.48%	11.80%	10.15%	10.27%	13.25%	11.20%	10.79%
DTE Energy Company	DTE	9.09%	8.61%	12.60%	13.22%	10.79%	11.27%	8.85%	12.91%	11.03%	10.27%	12.79%	11.21%	10.73%
NorthWestern Energy Group, Inc.	NWE	9.61%	9.98%	13.18%	12.77%	11.24%	10.91%	9.80%	12.97%	11.07%	10.27%	8.14%	10.29%	9.82%
Public Service Enterprise Group Inc.	PEG	9.03%	8.59%	12.75%	12.77%	10.90%	10.91%	8.81%	12.76%	10.91%	10.27%	12.79%	11.16%	10.69%
Southern Company	SO	10.06%	9.08%	12.24%	12.77%	10.50%	10.91%	9.57%	12.50%	10.71%	10.27%	14.70%	11.76%	11.31%
Wisconsin Energy Corporation	WEC	10.15%	9.20%	11.57%	11.85%	9.98%	10.20%	9.68%	11.71%	10.09%	10.27%	13.16%	11.21%	10.80%
GAS PROXY GROUP MEAN		10.19%	9.02%	11.96%	12.16%	10.28%	10.44%	9.61%	12.06%	10.36%	10.21%	10.03%	10.48%	10.05%
COMBINED PROXY GROUP MEAN		9.86%	9.05%	12.31%	12.59%	10.55%	10.78%	9.46%	12.45%	10.67%	10.25%	10.78%	10.73%	10.29%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of
James M. Coyne and Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 2502

June 4, 2024

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PROXY GROUP SELECTION

Company		[1] Pays Dividends (Yes/No)	[2] S&P Rating	[3] Positive Earnings Growth by more than one Analyst (Yes/No)	[4] % Regulated Net Operating Income / Total Net Operating Income (2020-2022)	[5] % Natural Gas Distribution Net Operating Income / Total Net Operating Income (2020-2022)	[6] Involved in Merger (Yes/No)
Atmos Energy Corporation	ATO	Yes	A-	Yes	100%	66%	No
New Jersey Resources Corporation	NJR	Yes	[7]	Yes	66%	61%	No
NiSource Inc.	NI	Yes	BBB+	Yes	100%	66%	No
ONE Gas, Inc.	OGS	Yes	A-	Yes	100%	100%	No
Southwest Gas Holding	SWX	Yes	BBB-	Yes	77%	77%	No
Spire, Inc.	SR	Yes	A-	Yes	89%	89%	No
Ameren Corporation	AEE	Yes	BBB+	Yes	100%	15%	No
Avista Corporation	AVA	Yes	BBB	Yes	100%	26%	No
Black Hills Corporation	BKH	Yes	BBB+	Yes	99%	53%	No
CenterPoint Energy, Inc.	CNP	Yes	BBB+	Yes	100%	45%	No
CMS Energy Corporation	CMS	Yes	BBB+	Yes	88%	30%	No
DTE Energy Company	DTE	Yes	BBB+	Yes	100%	22%	No
NorthWestern Energy Group, Inc.	NWE	Yes	BBB	Yes	100%	15%	No
Public Service Enterprise Group Inc.	PEG	Yes	BBB+	Yes	90%	21%	No
Southern Company	SO	Yes	BBB+	Yes	95%	18%	No
Wisconsin Energy Corporation	WEC	Yes	A-	Yes	99%	39%	No

[1] Source: Bloomberg Professional
[2] Source: S&P Capital IQ Pro
[3] Source: Value Line, Zacks and Yahoo Finance
[4] Source: Company 10-K reports, average of three most recent years
[5] Source: Company 10-K reports, average of three most recent years
[6] Source: Bloomberg Professional
[7] New Jersey Natural Gas Co is rated A1 by Moody's

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of
James M. Coyne and Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 2503

June 4, 2024

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30-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth	Low DCF ROE	Mean DCF ROE	High DCF ROE
Atmos Energy Corporation	ATO	$3.22	$116.44	2.77%	2.86%	7.00%	7.50%	7.00%	7.17%	9.86%	10.03%	10.37%
New Jersey Resources Corporation	NJR	$1.68	$42.55	3.95%	4.06%	5.00%	6.00%	n/a	5.50%	9.05%	9.56%	10.07%
NiSource Inc.	NI	$1.06	$27.40	3.87%	4.02%	9.50%	7.30%	6.00%	7.60%	9.99%	11.62%	13.55%
ONE Gas, Inc.	OGS	$2.64	$63.34	4.17%	4.27%	4.00%	5.00%	5.00%	4.67%	8.25%	8.93%	9.27%
Southwest Gas Holding	SWX	$2.48	$73.96	3.35%	3.46%	10.00%	4.00%	6.00%	6.67%	7.42%	10.13%	13.52%
Spire, Inc.	SR	$3.02	$60.13	5.02%	5.16%	4.50%	6.36%	5.00%	5.29%	9.64%	10.44%	11.54%
Ameren Corporation	AEE	$2.68	$72.88	3.68%	3.79%	6.50%	4.80%	6.50%	5.93%	8.57%	9.72%	10.30%
Avista Corporation	AVA	$1.90	$34.60	5.49%	5.66%	6.00%	6.20%	n/a	6.10%	11.66%	11.76%	11.86%
Black Hills Corporation	BKH	$2.60	$53.35	4.87%	4.92%	3.50%	0.70%	n/a	2.10%	5.59%	7.02%	8.46%
CenterPoint Energy, Inc.	CNP	$0.80	$28.19	2.84%	2.94%	6.00%	7.70%	7.00%	6.90%	8.92%	9.836%	10.65%
CMS Energy Corporation	CMS	$2.06	$59.10	3.49%	3.60%	5.00%	7.40%	7.40%	6.60%	8.57%	10.20%	11.01%
DTE Energy Company	DTE	$4.08	$108.98	3.74%	3.84%	4.50%	5.10%	6.00%	5.20%	8.33%	9.04%	9.86%
NorthWestern Energy Group, Inc.	NWE	$2.60	$49.67	5.23%	5.35%	4.00%	4.50%	n/a	4.25%	9.34%	9.60%	9.85%
Public Service Enterprise Group Inc.	PEG	$2.40	$66.19	3.63%	3.72%	4.00%	5.25%	6.20%	5.15%	7.70%	8.87%	9.94%
Southern Company	SO	$2.80	$70.95	3.95%	4.06%	6.50%	7.30%	4.00%	5.93%	8.03%	10.00%	11.39%
Wisconsin Energy Corporation	WEC	$3.34	$80.85	4.13%	4.25%	6.00%	5.84%	5.90%	5.91%	10.09%	10.17%	10.26%
GAS PROXY GROUP MEAN				3.85%	3.97%	6.67%	6.03%	5.80%	6.15%	9.03%	10.12%	11.39%
COMBINED PROXY GROUP MEAN				4.01%	4.12%	5.75%	5.68%	6.00%	5.69%	8.81%	9.81%	10.74%

Notes
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-day average as of April 30, 2024
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

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90-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth	Low DCF ROE	Mean DCF ROE	High DCF ROE
Atmos Energy Corporation	ATO	$3.22	$115.12	2.80%	2.90%	7.00%	7.50%	7.00%	7.17%	9.89%	10.06%	10.40%
New Jersey Resources Corporation	NJR	$1.68	$42.50	3.95%	4.06%	5.00%	6.00%	n/a	5.50%	9.05%	9.56%	10.07%
NiSource Inc.	NI	$1.06	$26.58	3.99%	4.14%	9.50%	7.30%	6.00%	7.60%	10.11%	11.74%	13.68%
ONE Gas, Inc.	OGS	$2.64	$62.10	4.25%	4.35%	4.00%	5.00%	5.00%	4.67%	8.34%	9.02%	9.36%
Southwest Gas Holding	SWX	$2.48	$67.07	3.70%	3.82%	10.00%	4.00%	6.00%	6.67%	7.77%	10.49%	13.88%
Spire, Inc.	SR	$3.02	$60.13	5.02%	5.16%	4.50%	6.36%	5.00%	5.29%	9.64%	10.44%	11.54%
Ameren Corporation	AEE	$2.68	$71.69	3.74%	3.85%	6.50%	4.80%	6.50%	5.93%	8.63%	9.78%	10.36%
Avista Corporation	AVA	$1.90	$34.37	5.53%	5.70%	6.00%	6.20%	n/a	6.10%	11.69%	11.80%	11.90%
Black Hills Corporation	BKH	$2.60	$52.80	4.92%	4.98%	3.50%	0.70%	n/a	2.10%	5.64%	7.08%	8.51%
CenterPoint Energy, Inc.	CNP	$0.80	$28.11	2.85%	2.94%	6.00%	7.70%	7.00%	6.90%	8.93%	9.844%	10.66%
CMS Energy Corporation	CMS	$2.06	$58.21	3.54%	3.66%	5.00%	7.40%	7.40%	6.60%	8.63%	10.26%	11.07%
DTE Energy Company	DTE	$4.08	$108.26	3.77%	3.87%	4.50%	5.10%	6.00%	5.20%	8.35%	9.07%	9.88%
NorthWestern Energy Group, Inc.	NWE	$2.60	$49.20	5.28%	5.40%	4.00%	4.50%	n/a	4.25%	9.39%	9.65%	9.90%
Public Service Enterprise Group Inc.	PEG	$2.40	$62.51	3.84%	3.94%	4.00%	5.25%	6.20%	5.15%	7.92%	9.09%	10.16%
Southern Company	SO	$2.80	$69.61	4.02%	4.14%	6.50%	7.30%	4.00%	5.93%	8.10%	10.08%	11.47%
Wisconsin Energy Corporation	WEC	$3.34	$80.78	4.13%	4.26%	6.00%	5.84%	5.90%	5.91%	10.10%	10.17%	10.26%
GAS PROXY GROUP MEAN				3.95%	4.07%	6.67%	6.03%	5.80%	6.15%	9.13%	10.22%	11.49%
COMBINED PROXY GROUP MEAN				4.08%	4.20%	5.75%	5.68%	6.00%	5.69%	8.89%	9.88%	10.82%

Notes
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 90-day average as of April 30, 2024
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

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180-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth	Low DCF ROE	Mean DCF ROE	High DCF ROE
Atmos Energy Corporation	ATO	$3.22	$113.73	2.83%	2.93%	7.00%	7.50%	7.00%	7.17%	9.93%	10.10%	10.44%
New Jersey Resources Corporation	NJR	$1.68	$42.44	3.96%	4.07%	5.00%	6.00%	n/a	5.50%	9.06%	9.57%	10.08%
NiSource Inc.	NI	$1.06	$26.28	4.03%	4.19%	9.50%	7.30%	6.00%	7.60%	10.15%	11.79%	13.72%
ONE Gas, Inc.	OGS	$2.64	$64.57	4.09%	4.18%	4.00%	5.00%	5.00%	4.67%	8.17%	8.85%	9.19%
Southwest Gas Holding	SWX	$2.48	$63.94	3.88%	4.01%	10.00%	4.00%	6.00%	6.67%	7.96%	10.67%	14.07%
Spire, Inc.	SR	$3.02	$59.61	5.07%	5.20%	4.50%	6.36%	5.00%	5.29%	9.68%	10.49%	11.59%
Ameren Corporation	AEE	$2.68	$74.63	3.59%	3.70%	6.50%	4.80%	6.50%	5.93%	8.48%	9.63%	10.21%
Avista Corporation	AVA	$1.90	$34.00	5.59%	5.76%	6.00%	6.20%	n/a	6.10%	11.76%	11.86%	11.96%
Black Hills Corporation	BKH	$2.60	$52.55	4.95%	5.00%	3.50%	0.70%	n/a	2.10%	5.67%	7.10%	8.53%
CenterPoint Energy, Inc.	CNP	$0.80	$27.99	2.86%	2.96%	6.00%	7.70%	7.00%	6.90%	8.94%	9.86%	10.67%
CMS Energy Corporation	CMS	$2.06	$57.01	3.61%	3.73%	5.00%	7.40%	7.40%	6.60%	8.70%	10.33%	11.15%
DTE Energy Company	DTE	$4.08	$105.40	3.87%	3.97%	4.50%	5.10%	6.00%	5.20%	8.46%	9.17%	9.99%
NorthWestern Energy Group, Inc.	NWE	$2.60	$49.68	5.23%	5.34%	4.00%	4.50%	n/a	4.25%	9.34%	9.59%	9.85%
Public Service Enterprise Group Inc.	PEG	$2.40	$61.78	3.88%	3.98%	4.00%	5.25%	6.20%	5.15%	7.96%	9.13%	10.21%
Southern Company	SO	$2.80	$69.02	4.06%	4.18%	6.50%	7.30%	4.00%	5.93%	8.14%	10.11%	11.50%
Wisconsin Energy Corporation	WEC	$3.34	$81.94	4.08%	4.20%	6.00%	5.84%	5.90%	5.91%	10.04%	10.11%	10.20%
GAS PROXY GROUP MEAN				3.98%	4.10%	6.67%	6.03%	5.80%	6.15%	9.16%	10.24%	11.52%
COMBINED PROXY GROUP MEAN				4.10%	4.21%	5.75%	5.68%	6.00%	5.69%	8.90%	9.90%	10.83%

Notes
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 180-day average as of April 30, 2024
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of
James M. Coyne and Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 2504

June 4, 2024

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30-DAY MULTI-STAGE DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	Annualized Dividend	Stock Price	Growth Rate, Years 1-5	Year 6	Year 7	Year 8	Year 9	Year 10	GDP Growth (perpetuity)	ROE
Atmos Energy Corporation	ATO	$3.22	$116.44	7.17%	6.68%	6.19%	5.71%	5.22%	4.73%	4.24%	7.84%
New Jersey Resources Corporation	NJR	$1.68	$42.55	5.50%	5.29%	5.08%	4.87%	4.66%	4.45%	4.24%	8.88%
NiSource Inc.	NI	$1.06	$27.40	7.60%	7.04%	6.48%	5.92%	5.36%	4.80%	4.24%	9.41%
ONE Gas, Inc.	OGS	$2.64	$63.34	4.67%	4.60%	4.53%	4.46%	4.38%	4.31%	4.24%	8.89%
Southwest Gas Holding	SWX	$2.48	$73.96	6.67%	6.26%	5.86%	5.46%	5.05%	4.65%	4.24%	8.47%
Spire, Inc.	SR	$3.02	$60.13	5.29%	5.11%	4.94%	4.77%	4.59%	4.42%	4.24%	10.08%
Ameren Corporation	AEE	$2.68	$72.88	5.93%	5.65%	5.37%	5.09%	4.81%	4.53%	4.24%	8.68%
Avista Corporation	AVA	$1.90	$34.60	6.10%	5.79%	5.48%	5.17%	4.86%	4.55%	4.24%	10.96%
Black Hills Corporation	BKH	$2.60	$53.35	2.10%	2.46%	2.81%	3.17%	3.53%	3.89%	4.24%	8.87%
CenterPoint Energy, Inc.	CNP	$0.80	$28.19	6.90%	6.46%	6.01%	5.57%	5.13%	4.69%	4.24%	7.87%
CMS Energy Corporation	CMS	$2.06	$59.10	6.60%	6.21%	5.81%	5.42%	5.03%	4.64%	4.24%	8.62%
DTE Energy Company	DTE	$4.08	$108.98	5.20%	5.04%	4.88%	4.72%	4.56%	4.40%	4.24%	8.55%
NorthWestern Energy Group, Inc.	NWE	$2.60	$49.67	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.24%	9.96%
Public Service Enterprise Group Inc.	PEG	$2.40	$66.19	5.15%	5.00%	4.85%	4.70%	4.55%	4.40%	4.24%	8.40%
Southern Company	SO	$2.80	$70.95	5.93%	5.65%	5.37%	5.09%	4.81%	4.53%	4.24%	9.00%
Wisconsin Energy Corporation	WEC	$3.34	$80.85	5.91%	5.64%	5.36%	5.08%	4.80%	4.52%	4.24%	9.22%
GAS PROXY GROUP MEAN											8.93%
COMBINED PROXY GROUP MEAN											8.98%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 30-day average as of April 30, 2024
[3] Source: Exhibit NW Natural/405
[4] Equals [3] − ([3] − [9]) / 6
[5] Equals [4] − ([3] − [9]) / 6
[6] Equals [5] − ([3] − [9]) / 6
[7] Equals [6] − ([3] − [9]) / 6
[8] Equals [7] − ([3] − [9]) / 6
[9] Sources: Blue Chip Financial Forecasts 2030-2034 Real GDP growth (2.0%) and projected Inflation (2.2%) = ((1+GDP) x (1+ CPI)) - 1
[10] Internal rate of return

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90-DAY MULTI-STAGE DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	Annualized Dividend	Stock Price	Growth Rate, Years 1-5	Year 6	Year 7	Year 8	Year 9	Year 10	GDP Growth (perpetuity)	ROE
Atmos Energy Corporation	ATO	$3.22	$115.12	7.17%	6.68%	6.19%	5.71%	5.22%	4.73%	4.24%	7.88%
New Jersey Resources Corporation	NJR	$1.68	$42.50	5.50%	5.29%	5.08%	4.87%	4.66%	4.45%	4.24%	8.89%
NiSource Inc.	NI	$1.06	$26.58	7.60%	7.04%	6.48%	5.92%	5.36%	4.80%	4.24%	9.57%
ONE Gas, Inc.	OGS	$2.64	$62.10	4.67%	4.60%	4.53%	4.46%	4.38%	4.31%	4.24%	8.99%
Southwest Gas Holding	SWX	$2.48	$67.07	6.67%	6.26%	5.86%	5.46%	5.05%	4.65%	4.24%	8.91%
Spire, Inc.	SR	$3.02	$60.13	5.29%	5.11%	4.94%	4.77%	4.59%	4.42%	4.24%	10.08%
Ameren Corporation	AEE	$2.68	$71.69	5.93%	5.65%	5.37%	5.09%	4.81%	4.53%	4.24%	8.75%
Avista Corporation	AVA	$1.90	$34.37	6.10%	5.79%	5.48%	5.17%	4.86%	4.55%	4.24%	11.00%
Black Hills Corporation	BKH	$2.60	$52.80	2.10%	2.46%	2.81%	3.17%	3.53%	3.89%	4.24%	8.92%
CenterPoint Energy, Inc.	CNP	$0.80	$28.11	6.90%	6.46%	6.01%	5.57%	5.13%	4.69%	4.24%	7.88%
CMS Energy Corporation	CMS	$2.06	$58.21	6.60%	6.21%	5.81%	5.42%	5.03%	4.64%	4.24%	8.69%
DTE Energy Company	DTE	$4.08	$108.26	5.20%	5.04%	4.88%	4.72%	4.56%	4.40%	4.24%	8.58%
NorthWestern Energy Group, Inc.	NWE	$2.60	$49.20	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.24%	10.02%
Public Service Enterprise Group Inc.	PEG	$2.40	$62.51	5.15%	5.00%	4.85%	4.70%	4.55%	4.40%	4.24%	8.65%
Southern Company	SO	$2.80	$69.61	5.93%	5.65%	5.37%	5.09%	4.81%	4.53%	4.24%	9.10%
Wisconsin Energy Corporation	WEC	$3.34	$80.78	5.91%	5.64%	5.36%	5.08%	4.80%	4.52%	4.24%	9.23%
GAS PROXY GROUP MEAN											9.05%
COMBINED PROXY GROUP MEAN											9.07%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 90-day average as of April 30, 2024
[3] Source: Exhibit NW Natural/405
[4] Equals [3] − ([3] − [9]) / 6
[5] Equals [4] − ([3] − [9]) / 6
[6] Equals [5] − ([3] − [9]) / 6
[7] Equals [6] − ([3] − [9]) / 6
[8] Equals [7] − ([3] − [9]) / 6
[9] Sources: Blue Chip Financial Forecasts 2030-2034 Real GDP growth (2.0%) and projected Inflation (2.2%) = ((1+GDP) x (1+ CPI)) - 1
[10] Internal rate of return

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180-DAY MULTI-STAGE DCF

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Growth Rate, Years 1-5	[4] Year 6	[5] Year 7	[6] Year 8	[7] Year 9	[8] Year 10	[9] GDP Growth (perpetuity)	[10] ROE
Atmos Energy Corporation	ATO	$3.22	$113.73	7.17%	6.68%	6.19%	5.71%	5.22%	4.73%	4.24%	7.93%
New Jersey Resources Corporation	NJR	$1.68	$42.44	5.50%	5.29%	5.08%	4.87%	4.66%	4.45%	4.24%	8.89%
NiSource Inc.	NI	$1.06	$26.28	7.60%	7.04%	6.48%	5.92%	5.36%	4.80%	4.24%	9.63%
ONE Gas, Inc.	OGS	$2.64	$64.57	4.67%	4.60%	4.53%	4.46%	4.38%	4.31%	4.24%	8.80%
Southwest Gas Holding	SWX	$2.48	$63.94	6.67%	6.26%	5.86%	5.46%	5.05%	4.65%	4.24%	9.14%
Spire, Inc.	SR	$3.02	$59.61	5.29%	5.11%	4.94%	4.77%	4.59%	4.42%	4.24%	10.14%
Ameren Corporation	AEE	$2.68	$74.63	5.93%	5.65%	5.37%	5.09%	4.81%	4.53%	4.24%	8.57%
Avista Corporation	AVA	$1.90	$34.00	6.10%	5.79%	5.48%	5.17%	4.86%	4.55%	4.24%	11.08%
Black Hills Corporation	BKH	$2.60	$52.55	2.10%	2.46%	2.81%	3.17%	3.53%	3.89%	4.24%	8.95%
CenterPoint Energy, Inc.	CNP	$0.80	$27.99	6.90%	6.46%	6.01%	5.57%	5.13%	4.69%	4.24%	7.90%
CMS Energy Corporation	CMS	$2.06	$57.01	6.60%	6.21%	5.81%	5.42%	5.03%	4.64%	4.24%	8.79%
DTE Energy Company	DTE	$4.08	$105.40	5.20%	5.04%	4.88%	4.72%	4.56%	4.40%	4.24%	8.70%
NorthWestern Energy Group, Inc.	NWE	$2.60	$49.68	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.24%	9.96%
Public Service Enterprise Group Inc.	PEG	$2.40	$61.78	5.15%	5.00%	4.85%	4.70%	4.55%	4.40%	4.24%	8.70%
Southern Company	SO	$2.80	$69.02	5.93%	5.65%	5.37%	5.09%	4.81%	4.53%	4.24%	9.14%
Wisconsin Energy Corporation	WEC	$3.34	$81.94	5.91%	5.64%	5.36%	5.08%	4.80%	4.52%	4.24%	9.16%
GAS PROXY GROUP MEAN											9.09%
COMBINED PROXY GROUP MEAN											9.09%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 180-day average as of April 30, 2024
[3] Source: Exhibit NW Natural/405
[4] Equals [3] − ([3] − [9]) / 6
[5] Equals [4] − ([3] − [9]) / 6
[6] Equals [5] − ([3] − [9]) / 6
[7] Equals [6] − ([3] − [9]) / 6
[8] Equals [7] − ([3] − [9]) / 6
[9] Sources: Blue Chip Financial Forecasts 2030-2034 Real GDP growth (2.0%) and projected Inflation (2.2%) = ((1+GDP) x (1+ CPI)) - 1
[10] Internal rate of return

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of
James M. Coyne and Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 2505

June 4, 2024

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MARKET RISK PREMIUM DERIVED FROM S&P EARNINGS AND ESTIMATE REPORT

[1] S&P's estimate of the S&P 500 Dividend Yield	1.47%
[2] S&P's estimate of the S&P 500 Growth Rate	14.09%
[3] S&P 500 Estimated Required Market Return	15.66%

Notes:
[1] Source: S&P Dow Jones Indices, S&P 500 Earnings and Estimate Report, April 30, 2024
[2] Source: S&P Dow Jones Indices, S&P 500 Earnings and Estimate Report, April 30, 2024
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]

MARKET RISK PREMIUM CALCULATION USING CAP. WEIGHTED BLOOMBERG GROWTH RATES

[4] Cap. Weighted Estimate of the S&P 500 Dividend Yield	1.48%
[5] Cap. Weighted Estimate of the S&P 500 Growth Rate	14.08%
[6] Cap. Weighted S&P 500 Estimated Required Market Return	15.66%

Notes:
[4] Source: Bloomberg Professional, as of April 30, 2024
[5] Source: Bloomberg Professional, as of April 30, 2024
[6] Equals ([4] x (1 + (0.5 x [5]))) + [5]

Name	Ticker	Shares Outst'g	Price	Dividend Yield	Bloomberg Long-Term Growth Estimate	Market Cap Excl. n/a Growth	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
LyondellBasell Industries NV	LYB	325.62	99.97	5.00	8.00	32,552.43	0.08%	0.00%	0.63%
American Express Co	AXP	719.30	234.03	1.20	15.22	168,338.48	0.40%	0.00%	6.15%
Verizon Communications Inc	VZ	4209.26	39.49	6.74	1.22	166,223.48	0.40%	0.03%	0.48%
Broadcom Inc	AVGO	463.42	1300.27	1.62	14.20	602,572.42	1.45%	0.02%	20.54%
Boeing Co/The	BA	613.88	167.84	n/a	74.41	103,034.29	0.25%	n/a	18.40%
Solventum Corp	SOLV	172.71	65.01	n/a	-4.00	11,227.81	0.03%	n/a	-0.11%
Caterpillar Inc	CAT	489.05	334.57	1.55	15.00	163,622.46	0.39%	0.01%	5.89%
JPMorgan Chase & Co	JPM	2872.09	191.74	2.40	3.50	550,694.73	1.32%	0.03%	4.63%
Chevron Corp	CVX	1847.32	161.27	4.04	7.00	297,917.30	0.72%	0.03%	5.01%
Coca-Cola Co/The	KO	4311.19	61.77	3.14	6.36	266,302.27	0.64%	0.02%	4.07%
AbbVie Inc	ABBV	1770.65	162.64	3.81	8.62	287,978.03	0.69%	0.03%	5.96%
Walt Disney Co/The	DIS	1834.33	111.10	0.81	21.90	203,793.95	0.49%	0.00%	10.71%
Corpay Inc	CPAY	71.85	302.14	n/a	13.65	21,709.97	0.05%	n/a	0.71%
Extra Space Storage Inc	EXR	211.62	134.28	4.83	1.62	28,416.33	0.07%	0.00%	0.11%
Exxon Mobil Corp	XOM	3943.01	118.27	3.21	-12.00	466,339.44	1.12%	0.04%	-13.43%
Phillips 66	PSX	423.95	143.21	3.21	n/a	n/a	n/a	n/a	
General Electric Co	GE	1094.61	161.82	0.69	23.50	177,129.30	0.43%	0.00%	9.99%
HP Inc	HPQ	978.48	28.09	3.92	0.50	27,485.53	0.07%	0.00%	0.03%
Home Depot Inc/The	HD	991.03	334.22	2.69	4.31	331,222.38	0.79%	0.02%	3.43%
Monolithic Power Systems Inc	MPWR	48.66	669.33	0.75	16.00	32,570.27	0.08%	0.00%	1.25%
International Business Machines Corp	IBM	918.60	166.20	4.02	3.19	152,671.82	0.37%	0.01%	1.17%
Johnson & Johnson	JNJ	2409.78	144.59	3.43	5.05	348,430.52	0.84%	0.03%	4.22%
Lululemon Athletica Inc	LULU	120.89	360.60	n/a	n/a	n/a	n/a	n/a	
McDonald's Corp	MCD	721.01	273.04	2.45	7.79	196,863.21	0.47%	0.01%	3.68%
Merck & Co Inc	MRK	2533.03	129.22	2.38	39.45	327,317.88	0.79%	0.02%	30.99%
3M Co	MMM	553.36	96.51	6.26	0.00	53,404.87	0.13%	0.01%	0.00%
American Water Works Co Inc	AWK	194.76	122.32	2.31	7.70	23,822.43	0.06%	0.00%	0.44%
Bank of America Corp	BAC	7820.37	37.01	2.59	n/a	n/a	n/a	n/a	
Pfizer Inc	PFE	5646.78	25.62	6.56	9.59	144,670.45	0.35%	0.02%	3.33%
Procter & Gamble Co/The	PG	2360.14	163.20	2.47	8.09	385,174.03	0.92%	0.02%	7.48%
AT&T Inc	T	7170.00	16.89	6.57	2.78	121,101.30	0.29%	0.02%	0.81%
Travelers Cos Inc/The	TRV	228.99	212.16	1.98	18.24	48,583.15	0.12%	0.00%	2.13%
RTX Corp	RTX	1329.51	101.52	2.32	10.21	134,971.45	0.32%	0.01%	3.31%
Analog Devices Inc	ADI	495.91	200.61	1.83	4.50	99,484.10	0.24%	0.00%	1.07%
Walmart Inc	WMT	8058.05	59.35	1.40	7.00	478,245.21	1.15%	0.02%	8.03%
Cisco Systems Inc	CSCO	4049.19	46.98	3.41	7.50	190,230.81	0.46%	0.02%	3.42%
Intel Corp	INTC	4256.87	30.47	1.64	0.41	129,706.89	0.31%	0.01%	0.13%
General Motors Co	GM	1140.40	44.53	1.08	15.71	50,781.79	0.12%	0.00%	1.91%
Microsoft Corp	MSFT	7432.31	389.33	0.77	16.54	2,893,619.69	6.95%	0.05%	114.85%
Dollar General Corp	DG	219.67	139.19	1.70	-1.47	30,576.01	0.07%	0.00%	-0.11%
Cigna Group/The	CI	283.65	357.04	1.57	11.62	101,273.32	0.24%	0.00%	2.82%
Kinder Morgan Inc	KMI	2219.38	18.28	6.29	4.00	40,570.34	0.10%	0.01%	0.39%
Citigroup Inc	C	1911.37	61.33	3.46	17.34	117,224.14	0.28%	0.01%	4.88%
American International Group Inc	AIG	674.03	75.31	1.91	9.50	50,761.35	0.12%	0.00%	1.16%
Altria Group Inc	MO	1717.63	43.81	8.95	4.00	75,249.20	0.18%	0.02%	0.72%
HCA Healthcare Inc	HCA	264.49	309.82	0.85	9.57	81,942.74	0.20%	0.00%	1.88%
International Paper Co	IP	347.33	34.94	5.29	-2.00	12,135.78	0.03%	0.00%	-0.06%
Hewlett Packard Enterprise Co	HPE	1300.00	17.00	3.06	2.86	22,100.00	0.05%	0.00%	0.15%
Abbott Laboratories	ABT	1735.18	105.97	2.08	4.19	183,877.45	0.44%	0.01%	1.85%
Aflac Inc	AFL	575.41	83.65	2.39	6.69	48,132.88	0.12%	0.00%	0.77%
Air Products and Chemicals Inc	APD	222.31	236.34	3.00	9.40	52,539.80	0.13%	0.00%	1.19%
Super Micro Computer Inc	SMCI	58.55	858.80	n/a	54.91	50,282.74	0.12%	n/a	6.63%
Royal Caribbean Cruises Ltd	RCL	257.35	139.63	n/a	27.45	35,933.64	0.09%	n/a	2.37%
Hess Corp	HES	308.11	157.49	1.11	18.00	48,524.09	0.12%	0.00%	2.10%
Archer-Daniels-Midland Co	ADM	494.44	58.66	3.41	-2.35	29,003.73	0.07%	0.00%	-0.16%
Automatic Data Processing Inc	ADP	410.79	241.89	2.32	16.00	99,366.23	0.24%	0.01%	3.82%
Verisk Analytics Inc	VRSK	143.39	217.96	0.72	11.97	31,253.28	0.08%	0.00%	0.90%
AutoZone Inc	AZO	17.30	2956.40	n/a	14.75	51,154.59	0.12%	n/a	1.81%
Linde PLC	LIN	481.58	440.96	1.26	11.00	212,355.75	0.51%	0.01%	5.61%
Avery Dennison Corp	AVY	80.55	217.28	1.62	7.00	17,502.56	0.04%	0.00%	0.29%
Enphase Energy Inc	ENPH	136.06	108.76	n/a	19.27	14,798.21	0.04%	n/a	0.68%
MSCI Inc	MSCI	79.22	465.79	1.37	11.45	36,901.75	0.09%	0.00%	1.01%
Ball Corp	BALL	315.64	69.57	1.15	9.50	21,959.21	0.05%	0.00%	0.50%
Axon Enterprise Inc	AXON	75.46	313.66	n/a	n/a	n/a	n/a	n/a	
Dayforce Inc	DAY	156.60	61.37	n/a	n/a	n/a	n/a	n/a	

Name	Ticker	Shares Outst'g	Price	Dividend Yield	Bloomberg Long-Term Growth Estimate	Market Cap Excl. n/a Growth	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
Carrier Global Corp	CARR	901.01	61.49	1.24	7.87	55,403.23	0.13%	0.00%	1.05%
Bank of New York Mellon Corp/The	BK	747.82	56.49	2.97	10.00	42,244.13	0.10%	0.00%	1.01%
Otis Worldwide Corp	OTIS	404.32	91.20	1.71	9.00	36,874.26	0.09%	0.00%	0.80%
Baxter International Inc	BAX	508.00	40.37	2.87	2.73	20,507.96	0.05%	0.00%	0.13%
Becton Dickinson & Co	BDX	288.90	234.60	1.62	8.36	67,776.41	0.16%	0.00%	1.36%
Berkshire Hathaway Inc	BRK/B	1311.00	396.73	n/a	n/a	n/a	n/a	n/a	
Best Buy Co Inc	BBY	215.38	73.64	5.11	3.36	15,860.66	0.04%	0.00%	0.13%
Boston Scientific Corp	BSX	1469.90	71.87	n/a	12.08	105,641.35	0.25%	n/a	3.06%
Bristol-Myers Squibb Co	BMY	2027.10	43.94	5.46	-4.12	89,070.77	0.21%	0.01%	-0.88%
Brown-Forman Corp	BF/B	303.42	47.85	1.82	2.73	14,518.46	0.03%	0.00%	0.10%
Coterra Energy Inc	CTRA	751.85	27.36	3.07	n/a	n/a	n/a	n/a	
Campbell Soup Co	CPB	298.10	45.71	3.24	4.87	13,626.29	0.03%	0.00%	0.16%
Hilton Worldwide Holdings Inc	HLT	250.05	197.28	0.30	15.52	49,329.07	0.12%	0.00%	1.84%
Carnival Corp	CCL	1119.45	14.82	n/a	n/a	n/a	n/a	n/a	
Qorvo Inc	QRVO	96.55	116.84	n/a	17.72	11,280.67	0.03%	n/a	0.48%
Builders FirstSource Inc	BLDR	121.94	182.82	n/a	11.65	22,293.07	0.05%	n/a	0.62%
UDR Inc	UDR	329.33	38.08	4.46	6.06	12,540.85	0.03%	0.00%	0.18%
Clorox Co/The	CLX	124.19	147.87	3.25	13.23	18,363.68	0.04%	0.00%	0.58%
Paycom Software Inc	PAYC	58.15	187.98	0.80	5.50	10,931.04	0.03%	0.00%	0.14%
CMS Energy Corp	CMS	291.76	60.61	3.40	7.36	17,683.82	0.04%	0.00%	0.31%
Colgate-Palmolive Co	CL	820.44	91.92	2.18	8.18	75,414.94	0.18%	0.00%	1.48%
EPAM Systems Inc	EPAM	58.00	235.26	n/a	2.97	13,643.90	0.03%	n/a	0.10%
Comerica Inc	CMA	132.59	50.17	5.66	n/a	n/a	n/a	n/a	
Conagra Brands Inc	CAG	478.06	30.78	4.55	1.82	14,714.78	0.04%	0.00%	0.06%
Airbnb Inc	ABNB	438.09	158.57	n/a	19.82	69,467.46	0.17%	n/a	3.30%
Consolidated Edison Inc	ED	344.92	94.40	3.52	5.70	32,560.83	0.08%	0.00%	0.45%
Corning Inc	GLW	855.35	33.38	3.36	10.78	28,551.65	0.07%	0.00%	0.74%
Cummins Inc	CMI	141.86	282.49	2.38	6.07	40,073.18	0.10%	0.00%	0.58%
Caesars Entertainment Inc	CZR	216.42	35.82	n/a	-28.24	7,752.02	0.02%	n/a	-0.53%
Danaher Corp	DHR	740.69	246.62	0.44	-7.56	182,668.23	0.44%	0.00%	-3.31%
Target Corp	TGT	461.69	160.98	2.73	-2.13	74,322.86	0.18%	0.00%	-0.38%
Deere & Co	DE	278.36	391.41	1.50	-4.67	108,952.10	0.26%	0.00%	-1.22%
Dominion Energy Inc	D	837.59	50.98	5.24	10.65	42,700.49	0.10%	0.01%	1.09%
Dover Corp	DOV	137.43	179.30	1.14	9.50	24,641.20	0.06%	0.00%	0.56%
Alliant Energy Corp	LNT	252.72	49.80	3.86	7.00	12,585.41	0.03%	0.00%	0.21%
Steel Dynamics Inc	STLD	160.02	130.12	1.41	-1.63	20,821.54	0.05%	0.00%	-0.08%
Duke Energy Corp	DUK	771.00	98.26	4.17	6.65	75,758.46	0.18%	0.01%	1.21%
Regency Centers Corp	REG	184.58	59.22	4.53	3.63	10,930.89	0.03%	0.00%	0.10%
Eaton Corp PLC	ETN	399.89	318.26	1.18	15.00	127,269.63	0.31%	0.00%	4.58%
Ecolab Inc	ECL	285.91	226.15	1.01	12.50	64,659.00	0.16%	0.00%	1.94%
Revvity Inc	RVTY	123.53	102.47	0.27	8.26	12,657.61	0.03%	0.00%	0.25%
Emerson Electric Co	EMR	571.70	107.78	1.95	14.13	61,617.83	0.15%	0.00%	2.09%
EOG Resources Inc	EOG	580.00	132.13	2.75	5.00	76,635.66	0.18%	0.01%	0.92%
Aon PLC	AON	217.43	282.01	0.96	10.59	61,317.72	0.15%	0.00%	1.56%
Entergy Corp	ETR	213.27	106.67	4.24	7.02	22,749.83	0.05%	0.00%	0.38%
Equifax Inc	EFX	123.61	220.19	0.71	11.56	27,217.91	0.07%	0.00%	0.75%
EQT Corp	EQT	441.59	40.09	1.57	31.59	17,703.42	0.04%	0.00%	1.34%
IQVIA Holdings Inc	IQV	182.01	231.77	n/a	8.92	42,185.38	0.10%	n/a	0.90%
Gartner Inc	IT	77.63	412.59	n/a	10.78	32,029.36	0.08%	n/a	0.83%
FedEx Corp	FDX	246.08	261.78	1.93	13.00	64,419.08	0.15%	0.00%	2.01%
FMC Corp	FMC	124.82	59.01	3.93	8.00	7,365.45	0.02%	0.00%	0.14%
Brown & Brown Inc	BRO	285.25	81.54	0.64	9.56	23,259.20	0.06%	0.00%	0.53%
Ford Motor Co	F	3921.49	12.15	4.94	1.67	47,646.04	0.11%	0.01%	0.19%
NextEra Energy Inc	NEE	2023.71	66.97	3.08	8.10	135,528.13	0.33%	0.01%	2.63%
Franklin Resources Inc	BEN	526.09	22.84	5.43	n/a	n/a	n/a	n/a	
Garmin Ltd	GRMN	192.08	144.47	2.08	5.60	27,749.65	0.07%	0.00%	0.37%
Freeport-McMoRan Inc	FCX	1434.41	49.94	1.20	1.14	71,634.39	0.17%	0.00%	0.20%
Dexcom Inc	DXCM	397.68	127.39	n/a	30.31	50,660.96	0.12%	n/a	3.69%
General Dynamics Corp	GD	274.36	287.09	1.98	12.64	78,767.16	0.19%	0.00%	2.39%
General Mills Inc	GIS	564.55	70.46	3.35	4.00	39,778.12	0.10%	0.00%	0.38%
Genuine Parts Co	GPC	139.30	157.21	2.54	n/a	n/a	n/a	n/a	
Atmos Energy Corp	ATO	150.84	117.90	2.73	7.00	17,784.04	0.04%	0.00%	0.30%
WW Grainger Inc	GWW	49.07	921.35	0.89	n/a	n/a	n/a	n/a	
Halliburton Co	HAL	885.30	37.47	1.81	11.60	33,172.23	0.08%	0.00%	0.92%
Healthpeak Properties Inc	DOC	703.78	18.61	6.45	2.24	13,097.38	0.03%	0.00%	0.07%
L3Harris Technologies Inc	LHX	189.68	214.05	2.17	7.29	40,601.00	0.10%	0.00%	0.71%
Insulet Corp	PODD	70.02	171.94	n/a	33.03	12,039.58	0.03%	n/a	0.95%
Catalent Inc	CTLT	180.97	55.85	n/a	35.27	10,107.40	0.02%	n/a	0.86%
Fortive Corp	FTV	352.03	75.27	0.43	8.98	26,497.22	0.06%	0.00%	0.57%
Hershey Co/The	HSY	149.60	193.92	2.83	5.50	29,010.04	0.07%	0.00%	0.38%
Synchrony Financial	SYF	401.54	43.98	2.27	n/a	n/a	n/a	n/a	
Hormel Foods Corp	HRL	547.69	35.56	3.18	6.59	19,475.79	0.05%	0.00%	0.31%
Arthur J Gallagher & Co	AJG	216.80	234.69	1.02	12.32	50,880.79	0.12%	0.00%	1.50%
Mondelez International Inc	MDLZ	1341.36	71.94	2.36	8.55	96,497.37	0.23%	0.01%	1.98%
CenterPoint Energy Inc	CNP	633.03	29.14	2.75	7.95	18,446.55	0.04%	0.00%	0.35%
Humana Inc	HUM	120.50	302.09	1.17	-6.15	36,402.15	0.09%	0.00%	-0.54%
Willis Towers Watson PLC	WTW	102.24	251.14	1.40	12.37	25,675.55	0.06%	0.00%	0.76%
Illinois Tool Works Inc	ITW	298.75	244.11	2.29	7.27	72,926.64	0.18%	0.00%	1.27%
CDW Corp/DE	CDW	134.37	241.86	1.03	8.93	32,498.24	0.08%	0.00%	0.70%
Trane Technologies PLC	TT	226.35	317.34	1.06	13.47	71,830.54	0.17%	0.00%	2.32%
Interpublic Group of Cos Inc/The	IPG	377.42	30.44	4.34	4.94	11,488.79	0.03%	0.00%	0.14%
International Flavors & Fragrances Inc	IFF	255.32	84.65	1.89	-1.97	21,612.75	0.05%	0.00%	-0.10%
Generac Holdings Inc	GNRC	60.27	135.96	n/a	6.00	8,194.17	0.02%	n/a	0.12%
NXP Semiconductors NV	NXPI	255.68	256.19	1.58	20.00	65,503.68	0.16%	0.00%	3.14%

Name	Ticker	Shares Outst'g	Price	Dividend Yield	Bloomberg Long-Term Growth Estimate	Market Cap Excl. n/a Growth	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
Kellanova	K	340.68	57.86	3.87	8.42	19,711.63	0.05%	0.00%	0.40%
Broadridge Financial Solutions Inc	BR	117.77	193.41	1.65	n/a	n/a	n/a	n/a	
Kimberly-Clark Corp	KMB	336.71	136.53	3.57	7.72	45,970.88	0.11%	0.00%	0.85%
Kimco Realty Corp	KIM	674.13	18.63	5.15	2.80	12,559.10	0.03%	0.00%	0.08%
Oracle Corp	ORCL	2748.51	113.75	1.41	14.30	312,643.47	0.75%	0.01%	10.73%
Kroger Co/The	KR	721.69	55.38	2.09	4.76	39,967.08	0.10%	0.00%	0.46%
Lennar Corp	LEN	245.04	151.62	1.32	8.82	37,152.36	0.09%	0.00%	0.79%
Eli Lilly & Co	LLY	950.41	781.10	0.67	40.63	742,361.35	1.78%	0.01%	72.39%
Bath & Body Works Inc	BBWI	224.90	45.42	1.76	13.65	10,214.82	0.02%	0.00%	0.33%
Charter Communications Inc	CHTR	144.39	255.94	n/a	5.89	36,954.15	0.09%	n/a	0.52%
Loews Corp	L	222.07	75.15	0.33	n/a	n/a	n/a	n/a	
Lowe's Cos Inc	LOW	572.19	227.99	1.93	2.12	130,454.05	0.31%	0.01%	0.66%
Hubbell Inc	HUBB	53.68	370.52	1.32	18.00	19,890.63	0.05%	0.00%	0.86%
IDEX Corp	IEX	75.70	220.46	1.16	n/a	n/a	n/a	n/a	
Marsh & McLennan Cos Inc	MMC	492.72	199.43	1.42	6.90	98,263.95	0.24%	0.00%	1.63%
Masco Corp	MAS	220.24	68.45	1.69	8.64	15,075.70	0.04%	0.00%	0.31%
S&P Global Inc	SPGI	320.26	415.83	0.88	12.93	133,172.47	0.32%	0.00%	4.13%
Medtronic PLC	MDT	1327.82	80.24	3.44	3.83	106,544.52	0.26%	0.01%	0.98%
Viatris Inc	VTRS	1187.57	11.57	4.15	-1.69	13,740.17	0.03%	0.00%	-0.06%
CVS Health Corp	CVS	1260.48	67.71	3.93	7.62	85,347.10	0.20%	0.01%	1.56%
DuPont de Nemours Inc	DD	417.58	72.50	2.10	6.72	30,274.77	0.07%	0.00%	0.49%
Micron Technology Inc	MU	1107.37	112.96	0.41	-4.00	125,088.29	0.30%	0.00%	-1.20%
Motorola Solutions Inc	MSI	166.12	339.15	1.16	8.85	56,340.62	0.14%	0.00%	1.20%
Cboe Global Markets Inc	CBOE	105.58	181.15	1.21	14.28	19,126.18	0.05%	0.00%	0.66%
Laboratory Corp of America Holdings	LH	84.29	201.37	1.43	9.46	16,974.28	0.04%	0.00%	0.39%
Newmont Corp	NEM	1153.14	40.64	2.46	18.15	46,863.61	0.11%	0.00%	2.04%
NIKE Inc	NKE	1211.46	92.26	1.60	10.85	111,769.48	0.27%	0.00%	2.91%
NiSource Inc	NI	448.19	27.86	3.80	7.00	12,486.52	0.03%	0.00%	0.21%
Norfolk Southern Corp	NSC	225.91	230.32	2.34	n/a	n/a	n/a	n/a	
Principal Financial Group Inc	PFG	235.15	79.14	3.59	11.79	18,609.77	0.04%	0.00%	0.53%
Eversource Energy	ES	350.73	60.62	4.72	n/a	n/a	n/a	n/a	
Northrop Grumman Corp	NOC	147.99	485.03	1.54	18.93	71,779.59	0.17%	0.00%	3.26%
Wells Fargo & Co	WFC	3501.70	59.32	2.36	13.41	207,720.84	0.50%	0.01%	6.69%
Nucor Corp	NUE	239.98	168.53	1.28	0.83	40,443.83	0.10%	0.00%	0.08%
Occidental Petroleum Corp	OXY	879.50	66.14	1.33	20.00	58,170.06	0.14%	0.00%	2.79%
Omnicom Group Inc	OMC	195.83	92.84	3.02	7.46	18,181.23	0.04%	0.00%	0.33%
ONEOK Inc	OKE	583.64	79.12	5.01	1.56	46,177.60	0.11%	0.01%	0.17%
Raymond James Financial Inc	RJF	207.30	122.00	1.48	15.38	25,290.60	0.06%	0.00%	0.93%
PG&E Corp	PCG	2133.51	17.11	0.23	10.10	36,504.32	0.09%	0.00%	0.88%
Parker-Hannifin Corp	PH	128.41	544.91	1.20	16.28	69,972.44	0.17%	0.00%	2.73%
Rollins Inc	ROL	484.23	44.56	1.35	13.02	21,577.29	0.05%	0.00%	0.67%
PPL Corp	PPL	737.12	27.46	3.75	7.22	20,241.43	0.05%	0.00%	0.35%
ConocoPhillips	COP	1171.10	125.62	2.48	n/a	n/a	n/a	n/a	
PulteGroup Inc	PHM	210.34	111.42	0.72	7.65	23,436.31	0.06%	0.00%	0.43%
Pinnacle West Capital Corp	PNW	113.56	73.65	4.78	7.28	8,363.47	0.02%	0.00%	0.15%
PNC Financial Services Group Inc/The	PNC	397.85	153.26	4.05	15.32	60,973.72	0.15%	0.01%	2.24%
PPG Industries Inc	PPG	235.36	129.00	2.02	7.82	30,361.57	0.07%	0.00%	0.57%
Progressive Corp/The	PGR	585.70	208.25	0.19	32.49	121,972.03	0.29%	0.00%	9.51%
Veralto Corp	VLTO	246.85	93.68	0.38	n/a	n/a	n/a	n/a	
Public Service Enterprise Group Inc	PEG	498.59	69.08	3.47	6.28	34,442.39	0.08%	0.00%	0.52%
Robert Half Inc	RHI	105.12	69.14	3.07	7.15	7,267.79	0.02%	0.00%	0.12%
Cooper Cos Inc/The	COO	198.76	89.06	n/a	11.77	17,701.21	0.04%	n/a	0.50%
Edison International	EIX	383.93	71.06	4.39	7.80	27,281.71	0.07%	0.00%	0.51%
Schlumberger NV	SLB	1429.34	47.48	2.32	14.81	67,864.97	0.16%	0.00%	2.41%
Charles Schwab Corp/The	SCHW	1773.48	73.95	1.35	14.20	131,148.48	0.31%	0.00%	4.47%
Sherwin-Williams Co/The	SHW	253.55	299.61	0.95	9.56	75,965.82	0.18%	0.00%	1.74%
West Pharmaceutical Services Inc	WST	72.84	357.48	0.22	7.72	26,039.92	0.06%	0.00%	0.48%
J M Smucker Co/The	SJM	106.18	114.85	3.69	7.04	12,194.31	0.03%	0.00%	0.21%
Snap-on Inc	SNA	52.72	267.96	2.78	3.83	14,126.58	0.03%	0.00%	0.13%
AMETEK Inc	AME	231.21	174.66	0.64	7.56	40,383.31	0.10%	0.00%	0.73%
Uber Technologies Inc	UBER	2081.54	66.27	n/a	51.75	137,943.92	0.33%	n/a	17.13%
Southern Co/The	SO	1094.63	73.50	3.92	7.10	80,455.53	0.19%	0.01%	1.37%
Truist Financial Corp	TFC	1338.10	37.55	5.54	10.30	50,245.50	0.12%	0.01%	1.24%
Southwest Airlines Co	LUV	598.46	25.94	2.78	21.33	15,523.95	0.04%	0.00%	0.79%
W R Berkley Corp	WRB	256.55	76.97	0.57	11.50	19,746.58	0.05%	0.00%	0.55%
Stanley Black & Decker Inc	SWK	153.80	91.40	3.54	10.00	14,057.50	0.03%	0.00%	0.34%
Public Storage	PSA	175.83	259.45	4.63	3.51	45,618.83	0.11%	0.01%	0.38%
Arista Networks Inc	ANET	312.63	256.56	n/a	15.67	80,209.38	0.19%	n/a	3.02%
Sysco Corp	SYY	497.83	74.32	2.74	14.00	36,998.73	0.09%	0.00%	1.24%
Corteva Inc	CTVA	687.80	54.13	1.18	13.66	37,230.45	0.09%	0.00%	1.22%
Texas Instruments Inc	TXN	910.48	176.42	2.95	10.00	160,627.23	0.39%	0.01%	3.86%
Textron Inc	TXT	190.70	84.59	0.09	10.12	16,131.23	0.04%	0.00%	0.39%
Thermo Fisher Scientific Inc	TMO	381.31	568.72	0.27	n/a	n/a	n/a	n/a	
TJX Cos Inc/The	TJX	1132.97	94.09	1.59	10.00	106,601.52	0.26%	0.00%	2.56%
Globe Life Inc	GL	94.04	76.17	1.26	7.00	7,162.80	0.02%	0.00%	0.12%
Johnson Controls International plc	JCI	681.48	65.07	2.27	9.77	44,343.71	0.11%	0.00%	1.04%
Ulta Beauty Inc	ULTA	47.94	404.84	n/a	6.90	19,406.01	0.05%	n/a	0.32%
Union Pacific Corp	UNP	610.12	237.16	2.19	11.00	144,696.53	0.35%	0.01%	3.82%
Keysight Technologies Inc	KEYS	174.56	147.94	n/a	-0.99	25,823.81	0.06%	n/a	-0.06%
UnitedHealth Group Inc	UNH	920.08	483.70	1.55	11.58	445,042.70	1.07%	0.02%	12.37%
Blackstone Inc	BX	722.26	116.61	2.85	23.93	84,223.09	0.20%	0.01%	4.84%
Marathon Oil Corp	MRO	571.48	26.85	1.64	7.00	15,344.16	0.04%	0.00%	0.26%
Bio-Rad Laboratories Inc	BIO	23.42	269.75	n/a	n/a	n/a	n/a	n/a	
Ventas Inc	VTR	404.05	44.28	4.07	5.78	17,891.29	0.04%	0.00%	0.25%

Name	Ticker	Shares Outst'g	Price	Dividend Yield	Bloomberg Long-Term Growth Estimate	Market Cap Excl. n/a Growth	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
Vulcan Materials Co	VMC	132.27	257.63	0.71	15.78	34,077.24	0.08%	0.00%	1.29%
Weyerhaeuser Co	WY	729.62	30.17	2.65	n/a	n/a	n/a	n/a	
Williams Cos Inc/The	WMB	1218.43	38.36	4.95	2.50	46,738.78	0.11%	0.01%	0.28%
Constellation Energy Corp	CEG	315.12	185.94	0.76	9.00	58,593.60	0.14%	0.00%	1.27%
WEC Energy Group Inc	WEC	315.56	82.64	4.04	6.85	26,078.04	0.06%	0.00%	0.43%
Adobe Inc	ADBE	448.00	462.83	n/a	16.73	207,347.84	0.50%	n/a	8.32%
AES Corp/The	AES	710.29	17.90	3.85	7.85	12,714.14	0.03%	0.00%	0.24%
Expeditors International of Washington Inc	EXPD	143.90	111.31	1.24	2.85	16,017.40	0.04%	0.00%	0.11%
Amgen Inc	AMGN	536.38	273.94	3.29	4.49	146,934.84	0.35%	0.01%	1.58%
Apple Inc	AAPL	15441.88	170.33	0.56	13.00	2,630,215.59	6.31%	0.04%	82.07%
Autodesk Inc	ADSK	213.92	212.85	n/a	12.76	45,531.81	0.11%	n/a	1.39%
Cintas Corp	CTAS	101.46	658.34	0.82	10.83	66,797.15	0.16%	0.00%	1.74%
Comcast Corp	CMCSA	3914.18	38.11	3.25	8.67	149,169.48	0.36%	0.01%	3.10%
Molson Coors Beverage Co	TAP	197.55	57.26	3.07	4.67	11,311.77	0.03%	0.00%	0.13%
KLA Corp	KLAC	134.64	689.29	0.84	9.54	92,806.01	0.22%	0.00%	2.12%
Marriott International Inc/MD	MAR	288.26	236.13	0.88	4.74	68,066.60	0.16%	0.00%	0.77%
Fiserv Inc	FI	585.10	152.67	n/a	15.47	89,327.52	0.21%	n/a	3.32%
McCormick & Co Inc/MD	MKC	251.75	76.06	2.21	5.96	19,147.72	0.05%	0.00%	0.27%
PACCAR Inc	PCAR	524.01	106.11	1.13	12.00	55,602.81	0.13%	0.00%	1.60%
Costco Wholesale Corp	COST	443.50	722.90	0.64	10.16	320,609.04	0.77%	0.00%	7.82%
Stryker Corp	SYK	380.47	336.50	0.95	8.45	128,028.16	0.31%	0.00%	2.59%
Tyson Foods Inc	TSN	286.34	60.65	3.23	53.81	17,366.46	0.04%	0.00%	2.24%
Lamb Weston Holdings Inc	LW	144.39	83.34	1.73	11.56	12,033.55	0.03%	0.00%	0.33%
Applied Materials Inc	AMAT	830.90	198.65	0.81	14.23	165,057.69	0.40%	0.00%	5.64%
American Airlines Group Inc	AAL	653.54	13.51	n/a	-1.53	8,829.34	0.02%	n/a	-0.03%
Cardinal Health Inc	CAH	243.23	103.04	1.94	11.91	25,062.73	0.06%	0.00%	0.72%
Cincinnati Financial Corp	CINF	156.56	115.69	2.80	7.35	18,112.20	0.04%	0.00%	0.32%
Paramount Global	PARA	625.78	11.39	1.76	48.12	7,127.59	0.02%	0.00%	0.82%
DR Horton Inc	DHI	329.31	142.49	0.84	4.37	46,923.67	0.11%	0.00%	0.49%
Electronic Arts Inc	EA	267.35	126.82	0.60	12.50	33,905.33	0.08%	0.00%	1.02%
Fair Isaac Corp	FICO	24.71	1133.33	n/a	n/a	n/a	n/a	n/a	
Fastenal Co	FAST	572.55	67.94	2.30	n/a	n/a	n/a	n/a	
M&T Bank Corp	MTB	166.72	144.39	3.60	8.00	24,073.28	0.06%	0.00%	0.46%
Xcel Energy Inc	XEL	555.64	53.73	4.08	6.71	29,854.48	0.07%	0.00%	0.48%
Fifth Third Bancorp	FITB	683.81	36.46	3.84	25.00	24,931.79	0.06%	0.00%	1.50%
Gilead Sciences Inc	GILD	1246.97	65.20	4.72	13.35	81,302.38	0.20%	0.01%	2.61%
Hasbro Inc	HAS	138.79	61.30	4.57	17.10	8,507.89	0.02%	0.00%	0.35%
Huntington Bancshares Inc/OH	HBAN	1449.25	13.47	4.60	4.46	19,521.45	0.05%	0.00%	0.21%
Welltower Inc	WELL	597.92	95.28	2.56	14.52	56,969.44	0.14%	0.00%	1.99%
Biogen Inc	BIIB	145.60	214.82	n/a	4.62	31,277.15	0.08%	n/a	0.35%
Northern Trust Corp	NTRS	204.59	82.39	3.64	10.80	16,856.33	0.04%	0.00%	0.44%
Packaging Corp of America	PKG	89.76	172.98	2.89	3.00	15,525.82	0.04%	0.00%	0.11%
Paychex Inc	PAYX	359.96	118.81	3.00	7.00	42,767.20	0.10%	0.00%	0.72%
QUALCOMM Inc	QCOM	1116.00	165.85	2.05	10.65	185,088.60	0.44%	0.01%	4.73%
Ross Stores Inc	ROST	335.17	129.55	1.13	10.00	43,421.79	0.10%	0.00%	1.04%
IDEXX Laboratories Inc	IDXX	83.09	492.76	n/a	11.51	40,942.94	0.10%	n/a	1.13%
Starbucks Corp	SBUX	1132.20	88.49	2.58	13.62	100,188.38	0.24%	0.01%	3.28%
KeyCorp	KEY	942.78	14.49	5.66	9.83	13,660.82	0.03%	0.00%	0.32%
Fox Corp	FOXA	239.30	31.01	1.68	6.24	7,420.54	0.02%	0.00%	0.11%
Fox Corp	FOX	235.58	28.68	1.81	6.24	6,756.46	0.02%	0.00%	0.10%
State Street Corp	STT	301.50	72.49	3.81	8.06	21,856.02	0.05%	0.00%	0.42%
Norwegian Cruise Line Holdings Ltd	NCLH	425.66	18.92	n/a	48.23	8,053.43	0.02%	n/a	0.93%
US Bancorp	USB	1558.00	40.63	4.82	5.00	63,301.54	0.15%	0.01%	0.76%
A O Smith Corp	AOS	120.78	82.84	1.55	n/a	n/a	n/a	n/a	
Gen Digital Inc	GEN	636.91	20.14	2.48	11.51	12,827.37	0.03%	0.00%	0.35%
T Rowe Price Group Inc	TROW	223.30	109.57	4.53	5.88	24,466.98	0.06%	0.00%	0.35%
Waste Management Inc	WM	401.08	208.02	1.44	11.11	83,433.29	0.20%	0.00%	2.22%
Constellation Brands Inc	STZ	182.95	253.46	1.59	11.01	46,371.27	0.11%	0.00%	1.22%
Invesco Ltd	IVZ	449.80	14.17	5.79	8.71	6,373.67	0.02%	0.00%	0.13%
Intuit Inc	INTU	279.98	625.62	0.58	18.76	175,160.46	0.42%	0.00%	7.89%
Morgan Stanley	MS	1627.00	90.84	3.74	5.29	147,796.68	0.35%	0.01%	1.87%
Microchip Technology Inc	MCHP	540.39	91.98	1.96	2.30	49,704.89	0.12%	0.00%	0.27%
Chubb Ltd	CB	406.06	248.64	1.38	6.00	100,963.01	0.24%	0.00%	1.45%
Hologic Inc	HOLX	234.73	75.77	n/a	8.68	17,785.64	0.04%	n/a	0.37%
Citizens Financial Group Inc	CFG	458.49	34.11	4.93	-5.79	15,638.92	0.04%	0.00%	-0.22%
Jabil Inc	JBL	120.60	117.36	0.27	12.00	14,153.26	0.03%	0.00%	0.41%
O'Reilly Automotive Inc	ORLY	58.98	1013.26	n/a	10.51	59,764.10	0.14%	n/a	1.51%
Allstate Corp/The	ALL	263.76	170.06	2.16	53.70	44,854.86	0.11%	0.00%	5.78%
Equity Residential	EQR	378.94	64.40	4.19	4.75	24,403.74	0.06%	0.00%	0.28%
BorgWarner Inc	BWA	230.96	32.77	1.34	5.67	7,568.43	0.02%	0.00%	0.10%
Keurig Dr Pepper Inc	KDP	1355.57	33.70	2.55	7.12	45,682.84	0.11%	0.00%	0.78%
Host Hotels & Resorts Inc	HST	703.60	18.87	4.24	n/a	n/a	n/a	n/a	
Incyte Corp	INCY	224.54	52.05	n/a	25.33	11,687.36	0.03%	n/a	0.71%
Simon Property Group Inc	SPG	325.77	140.53	5.55	1.58	45,779.90	0.11%	0.01%	0.17%
Eastman Chemical Co	EMN	117.65	94.44	3.43	6.19	11,110.77	0.03%	0.00%	0.17%
AvalonBay Communities Inc	AVB	142.03	189.57	3.59	5.81	26,923.68	0.06%	0.00%	0.38%
Prudential Financial Inc	PRU	359.38	110.48	4.71	10.08	39,704.30	0.10%	0.00%	0.96%
United Parcel Service Inc	UPS	727.84	147.48	4.42	8.77	107,342.14	0.26%	0.01%	2.26%
Walgreens Boots Alliance Inc	WBA	862.71	17.73	5.64	-1.67	15,295.90	0.04%	0.00%	-0.06%
STERIS PLC	STE	98.81	204.56	1.02	n/a	n/a	n/a	n/a	
McKesson Corp	MCK	131.41	537.21	0.46	12.22	70,593.69	0.17%	0.00%	2.07%
Lockheed Martin Corp	LMT	239.94	464.93	2.71	2.39	111,554.37	0.27%	0.01%	0.64%
Cencora Inc	COR	199.48	239.05	0.85	10.10	47,686.17	0.11%	0.00%	1.16%
Capital One Financial Corp	COF	382.10	143.43	1.67	50.10	54,804.89	0.13%	0.00%	6.59%

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Waters Corp	WAT	59.31	309.04	n/a	7.23	18,329.16	0.04%	n/a	0.32%
Nordson Corp	NDSN	57.19	258.19	1.05	n/a	n/a	n/a	n/a	
Dollar Tree Inc	DLTR	217.98	118.25	n/a	14.10	25,776.49	0.06%	n/a	0.87%
Darden Restaurants Inc	DRI	119.36	153.41	3.42	10.97	18,310.86	0.04%	0.00%	0.48%
Evergy Inc	EVRG	229.75	52.45	4.90	5.00	12,050.18	0.03%	0.00%	0.14%
Match Group Inc	MTCH	268.01	30.82	n/a	36.66	8,260.13	0.02%	n/a	0.73%
Domino's Pizza Inc	DPZ	34.88	529.27	1.14	12.99	18,460.94	0.04%	0.00%	0.58%
NVR Inc	NVR	3.17	7438.85	n/a	4.87	23,566.28	0.06%	n/a	0.28%
NetApp Inc	NTAP	206.38	102.21	1.96	7.40	21,093.79	0.05%	0.00%	0.37%
Old Dominion Freight Line Inc	ODFL	217.67	181.71	0.57	13.12	39,553.54	0.09%	0.00%	1.25%
DaVita Inc	DVA	87.70	139.01	n/a	14.97	12,191.18	0.03%	n/a	0.44%
Hartford Financial Services Group Inc/The	HIG	295.76	96.89	1.94	7.00	28,655.70	0.07%	0.00%	0.48%
Iron Mountain Inc	IRM	293.10	77.52	3.35	n/a	n/a	n/a	n/a	
Estee Lauder Cos Inc/The	EL	232.93	146.71	1.80	17.63	34,173.31	0.08%	0.00%	1.45%
Cadence Design Systems Inc	CDNS	272.13	275.63	n/a	16.32	75,008.29	0.18%	n/a	2.94%
Tyler Technologies Inc	TYL	42.46	461.55	n/a	n/a	n/a	n/a	n/a	
Universal Health Services Inc	UHS	60.08	170.43	0.47	12.42	10,239.95	0.02%	0.00%	0.31%
Skyworks Solutions Inc	SWKS	160.44	106.59	2.55	5.08	17,101.73	0.04%	0.00%	0.21%
Quest Diagnostics Inc	DGX	111.09	138.18	2.17	-0.82	15,350.69	0.04%	0.00%	-0.03%
Rockwell Automation Inc	ROK	114.59	270.96	1.85	10.87	31,049.85	0.07%	0.00%	0.81%
Kraft Heinz Co/The	KHC	1215.64	38.61	4.14	3.87	46,935.78	0.11%	0.00%	0.44%
American Tower Corp	AMT	466.98	171.56	3.78	10.24	80,114.23	0.19%	0.01%	1.97%
Regeneron Pharmaceuticals Inc	REGN	107.94	890.66	n/a	13.00	96,141.40	0.23%	n/a	3.00%
Amazon.com Inc	AMZN	10387.38	175.00	n/a	24.94	1,817,791.68	4.36%	n/a	108.79%
Jack Henry & Associates Inc	JKHY	72.87	162.69	1.35	7.69	11,854.89	0.03%	0.00%	0.22%
Ralph Lauren Corp	RL	39.04	163.64	1.83	12.64	6,389.16	0.02%	0.00%	0.19%
Boston Properties Inc	BXP	157.05	61.89	6.33	0.37	9,719.76	0.02%	0.00%	0.01%
Amphenol Corp	APH	600.60	120.77	0.73	11.57	72,534.95	0.17%	0.00%	2.01%
Howmet Aerospace Inc	HWM	410.30	66.75	0.30	14.19	27,387.79	0.07%	0.00%	0.93%
Pioneer Natural Resources Co	PXD	233.62	269.32	3.80	-13.00	62,919.35	0.15%	0.01%	-1.96%
Valero Energy Corp	VLO	327.00	159.87	2.68	-24.00	52,276.85	0.13%	0.00%	-3.01%
Synopsys Inc	SNPS	152.54	530.59	n/a	18.70	80,938.32	0.19%	n/a	3.63%
Etsy Inc	ETSY	117.06	68.67	n/a	4.48	8,038.78	0.02%	n/a	0.09%
CH Robinson Worldwide Inc	CHRW	115.71	71.00	3.44	5.00	8,215.55	0.02%	0.00%	0.10%
Accenture PLC	ACN	670.42	300.91	1.71	10.00	201,736.68	0.48%	0.01%	4.84%
TransDigm Group Inc	TDG	55.61	1248.03	n/a	14.52	69,397.96	0.17%	n/a	2.42%
Yum! Brands Inc	YUM	281.50	141.25	1.90	8.59	39,761.88	0.10%	0.00%	0.82%
Prologis Inc	PLD	925.84	102.05	3.76	8.70	94,482.38	0.23%	0.01%	1.97%
FirstEnergy Corp	FE	575.52	38.34	4.43	6.65	22,065.28	0.05%	0.00%	0.35%
VeriSign Inc	VRSN	100.14	169.48	n/a	n/a	n/a	n/a	n/a	
Quanta Services Inc	PWR	145.75	258.56	0.14	10.00	37,684.86	0.09%	0.00%	0.90%
Henry Schein Inc	HSIC	128.48	69.28	n/a	9.38	8,901.16	0.02%	n/a	0.20%
Ameren Corp	AEE	266.51	73.87	3.63	6.00	19,687.17	0.05%	0.00%	0.28%
ANSYS Inc	ANSS	87.30	324.88	n/a	8.63	28,362.02	0.07%	n/a	0.59%
FactSet Research Systems Inc	FDS	38.12	416.89	0.94	10.32	15,890.18	0.04%	0.00%	0.39%
NVIDIA Corp	NVDA	2500.00	864.02	0.02	37.63	2,160,050.00	5.18%	0.00%	195.10%
Cognizant Technology Solutions Corp	CTSH	497.20	65.68	1.83	12.00	32,656.03	0.08%	0.00%	0.94%
Intuitive Surgical Inc	ISRG	354.71	370.62	n/a	16.21	131,461.14	0.32%	n/a	5.12%
Take-Two Interactive Software Inc	TTWO	170.75	142.81	n/a	22.73	24,384.24	0.06%	n/a	1.33%
Republic Services Inc	RSG	314.98	191.70	1.12	9.04	60,380.71	0.14%	0.00%	1.31%
eBay Inc	EBAY	518.00	51.54	2.10	1.99	26,697.72	0.06%	0.00%	0.13%
Goldman Sachs Group Inc/The	GS	324.53	426.71	2.58	9.31	138,478.92	0.33%	0.01%	3.09%
SBA Communications Corp	SBAC	108.02	186.12	2.11	8.00	20,104.87	0.05%	0.00%	0.39%
Sempra	SRE	632.15	71.63	3.46	3.85	45,280.90	0.11%	0.00%	0.42%
Moody's Corp	MCO	182.50	370.33	0.92	9.45	67,585.23	0.16%	0.00%	1.53%
ON Semiconductor Corp	ON	430.23	70.16	n/a	3.32	30,185.08	0.07%	n/a	0.24%
Booking Holdings Inc	BKNG	34.17	3452.03	1.01	22.55	117,959.32	0.28%	0.00%	6.38%
F5 Inc	FFIV	58.81	165.31	n/a	7.81	9,721.22	0.02%	n/a	0.18%
Akamai Technologies Inc	AKAM	153.21	100.93	n/a	8.33	15,463.59	0.04%	n/a	0.31%
Charles River Laboratories International Inc	CRL	51.35	229.00	n/a	14.00	11,759.15	0.03%	n/a	0.40%
MarketAxess Holdings Inc	MKTX	37.87	200.09	1.48	5.09	7,577.01	0.02%	0.00%	0.09%
Devon Energy Corp	DVN	635.00	51.18	3.44	n/a	n/a	n/a	n/a	
Bio-Techne Corp	TECH	157.19	63.21	0.51	2.00	9,936.11	0.02%	0.00%	0.05%
Alphabet Inc	GOOGL	5874.00	162.78	0.49	15.01	956,169.72	2.29%	0.01%	34.45%
Teleflex Inc	TFX	47.10	208.75	0.65	7.21	9,832.33	0.02%	0.00%	0.17%
Allegion plc	ALLE	87.44	121.56	1.58	7.25	10,629.33	0.03%	0.00%	0.18%
Netflix Inc	NFLX	430.97	550.64	n/a	35.61	237,306.57	0.57%	n/a	20.28%
Warner Bros Discovery Inc	WBD	2450.13	7.36	n/a	35.28	18,032.96	0.04%	n/a	1.53%
Agilent Technologies Inc	A	293.06	137.04	0.69	n/a	n/a	n/a	n/a	
Trimble Inc	TRMB	244.21	60.07	n/a	n/a	n/a	n/a	n/a	
Elevance Health Inc	ELV	232.42	528.58	1.23	10.02	122,851.51	0.29%	0.00%	2.95%
CME Group Inc	CME	360.03	209.64	2.19	4.90	75,475.64	0.18%	0.00%	0.89%
Juniper Networks Inc	JNPR	324.99	34.82	2.53	4.78	11,316.08	0.03%	0.00%	0.13%
BlackRock Inc	BLK	148.76	754.64	2.70	11.89	112,260.25	0.27%	0.01%	3.20%
DTE Energy Co	DTE	206.93	110.32	3.70	6.50	22,827.97	0.05%	0.00%	0.36%
Celanese Corp	CE	108.91	153.61	1.82	4.32	16,729.05	0.04%	0.00%	0.17%
Nasdaq Inc	NDAQ	575.21	59.85	1.60	5.72	34,426.14	0.08%	0.00%	0.47%
Philip Morris International Inc	PM	1554.56	94.94	5.48	8.23	147,589.64	0.35%	0.02%	2.92%
Ingersoll Rand Inc	IR	403.44	93.32	0.09	n/a	n/a	n/a	n/a	
Salesforce Inc	CRM	970.00	268.94	0.59	22.50	260,871.80	0.63%	0.00%	14.09%
Roper Technologies Inc	ROP	107.02	511.46	0.59	n/a	n/a	n/a	n/a	
Huntington Ingalls Industries Inc	HII	39.61	276.93	1.88	40.00	10,968.92	0.03%	0.00%	1.05%
MetLife Inc	MET	723.02	71.08	3.07	14.63	51,392.26	0.12%	0.00%	1.80%
Tapestry Inc	TPR	229.37	39.92	3.51	11.00	9,156.29	0.02%	0.00%	0.24%

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CSX Corp	CSX	1954.93	33.22	1.44	10.76	64,942.67	0.16%	0.00%	1.68%
Edwards Lifesciences Corp	EW	601.30	84.67	n/a	10.03	50,912.07	0.12%	n/a	1.23%
Ameriprise Financial Inc	AMP	100.19	411.79	1.44	n/a	n/a	n/a	n/a	
Zebra Technologies Corp	ZBRA	51.42	314.56	n/a	n/a	n/a	n/a	n/a	
Zimmer Biomet Holdings Inc	ZBH	205.08	120.28	0.80	6.89	24,667.50	0.06%	0.00%	0.41%
Camden Property Trust	CPT	106.97	99.68	4.13	5.93	10,662.67	0.03%	0.00%	0.15%
CBRE Group Inc	CBRE	305.70	86.89	n/a	n/a	n/a	n/a	n/a	
Mastercard Inc	MA	925.72	451.20	0.59	16.78	417,686.22	1.00%	0.01%	16.82%
CarMax Inc	KMX	157.39	67.97	n/a	25.76	10,697.66	0.03%	n/a	0.66%
Intercontinental Exchange Inc	ICE	572.62	128.76	1.40	10.83	73,730.04	0.18%	0.00%	1.92%
Fidelity National Information Services Inc	FIS	576.47	67.92	2.12	16.00	39,153.57	0.09%	0.00%	1.50%
Chipotle Mexican Grill Inc	CMG	27.47	3159.60	n/a	22.81	86,784.73	0.21%	n/a	4.75%
Wynn Resorts Ltd	WYNN	112.07	91.65	1.09	n/a	n/a	n/a	n/a	
Live Nation Entertainment Inc	LYV	230.80	88.91	n/a	n/a	n/a	n/a	n/a	
Assurant Inc	AIZ	51.98	174.40	1.65	5.04	9,064.96	0.02%	0.00%	0.11%
NRG Energy Inc	NRG	208.02	72.67	2.24	3.00	15,116.89	0.04%	0.00%	0.11%
Monster Beverage Corp	MNST	1040.64	53.45	n/a	12.45	55,621.99	0.13%	n/a	1.66%
Regions Financial Corp	RF	918.86	19.27	4.98	1.71	17,706.51	0.04%	0.00%	0.07%
Baker Hughes Co	BKR	998.00	32.62	2.58	27.93	32,554.69	0.08%	0.00%	2.18%
Mosaic Co/The	MOS	321.69	31.39	2.68	16.00	10,097.82	0.02%	0.00%	0.39%
Expedia Group Inc	EXPE	130.77	134.63	n/a	19.47	17,604.89	0.04%	n/a	0.82%
CF Industries Holdings Inc	CF	188.34	78.97	2.53	2.50	14,873.05	0.04%	0.00%	0.09%
APA Corp	APA	370.89	31.44	3.18	-2.00	11,660.72	0.03%	0.00%	-0.06%
Leidos Holdings Inc	LDOS	135.21	140.22	1.08	9.66	18,959.43	0.05%	0.00%	0.44%
Alphabet Inc	GOOG	5617.00	164.64	0.49	15.01	924,782.88	2.22%	0.01%	33.32%
First Solar Inc	FSLR	107.03	176.30	n/a	29.52	18,868.68	0.05%	n/a	1.34%
TE Connectivity Ltd	TEL	306.23	141.48	1.84	5.04	43,325.14	0.10%	0.00%	0.52%
Discover Financial Services	DFS	251.00	126.73	2.21	61.27	31,809.23	0.08%	0.00%	4.68%
Visa Inc	V	1574.15	268.61	0.77	13.53	422,832.97	1.01%	0.01%	13.73%
Mid-America Apartment Communities Inc	MAA	116.69	130.00	4.52	2.99	15,169.44	0.04%	0.00%	0.11%
Xylem Inc/NY	XYL	241.77	130.70	1.10	n/a	n/a	n/a	n/a	
Marathon Petroleum Corp	MPC	352.33	181.72	1.82	-12.00	64,025.41	0.15%	0.00%	-1.84%
Tractor Supply Co	TSCO	107.93	273.08	1.61	5.54	29,474.07	0.07%	0.00%	0.39%
Advanced Micro Devices Inc	AMD	1615.79	158.38	n/a	33.38	255,908.35	0.61%	n/a	20.50%
ResMed Inc	RMD	146.91	213.99	0.90	8.30	31,436.63	0.08%	0.00%	0.63%
Mettler-Toledo International Inc	MTD	21.39	1229.70	n/a	9.18	26,300.82	0.06%	n/a	0.58%
VICI Properties Inc	VICI	1043.14	28.55	5.81	1.98	29,781.56	0.07%	0.00%	0.14%
Copart Inc	CPRT	961.46	54.31	n/a	n/a	n/a	n/a	n/a	
Jacobs Solutions Inc	J	125.65	143.53	0.81	12.41	18,034.69	0.04%	0.00%	0.54%
Albemarle Corp	ALB	117.53	120.31	1.33	-19.50	14,139.43	0.03%	0.00%	-0.66%
Fortinet Inc	FTNT	763.03	63.18	n/a	18.05	48,208.30	0.12%	n/a	2.09%
Moderna Inc	MRNA	382.88	110.31	n/a	17.62	42,235.49	0.10%	n/a	1.79%
Essex Property Trust Inc	ESS	64.21	246.25	3.98	4.48	15,810.73	0.04%	0.00%	0.17%
CoStar Group Inc	CSGP	408.34	91.53	n/a	20.00	37,375.54	0.09%	n/a	1.79%
Realty Income Corp	O	861.15	53.54	5.76	4.82	46,105.97	0.11%	0.01%	0.53%
Westrock Co	WRK	258.15	47.96	2.52	5.28	12,380.78	0.03%	0.00%	0.16%
Westinghouse Air Brake Technologies Corp	WAB	176.39	161.08	0.50	15.49	28,412.10	0.07%	0.00%	1.06%
Pool Corp	POOL	38.33	362.53	1.21	4.73	13,895.41	0.03%	0.00%	0.16%
Western Digital Corp	WDC	326.53	70.83	n/a	-11.96	23,127.77	0.06%	n/a	-0.66%
PepsiCo Inc	PEP	1374.79	175.91	3.08	7.91	241,838.61	0.58%	0.02%	4.59%
Diamondback Energy Inc	FANG	178.34	201.13	6.13	2.00	35,869.52	0.09%	0.01%	0.17%
Palo Alto Networks Inc	PANW	323.10	290.89	n/a	20.50	93,986.56	0.23%	n/a	4.62%
ServiceNow Inc	NOW	205.38	693.33	n/a	25.00	142,397.50	0.34%	n/a	8.54%
Church & Dwight Co Inc	CHD	243.91	107.89	1.05	7.35	26,314.91	0.06%	0.00%	0.46%
Federal Realty Investment Trust	FRT	82.78	104.17	4.19	5.18	8,622.67	0.02%	0.00%	0.11%
MGM Resorts International	MGM	317.02	39.44	n/a	9.87	12,503.11	0.03%	n/a	0.30%
American Electric Power Co Inc	AEP	526.59	86.03	4.09	5.93	45,302.54	0.11%	0.00%	0.64%
Invitation Homes Inc	INVH	611.96	34.20	3.27	6.43	20,928.96	0.05%	0.00%	0.32%
PTC Inc	PTC	119.55	177.44	n/a	21.10	21,213.31	0.05%	n/a	1.07%
JB Hunt Transport Services Inc	JBHT	103.20	162.57	1.06	12.00	16,776.74	0.04%	0.00%	0.48%
Lam Research Corp	LRCX	130.74	894.41	0.89	11.92	116,931.59	0.28%	0.00%	3.34%
Mohawk Industries Inc	MHK	63.86	115.32	n/a	2.74	7,364.68	0.02%	n/a	0.05%
GE HealthCare Technologies Inc	GEHC	456.47	76.24	0.16	11.53	34,800.89	0.08%	0.00%	0.96%
Pentair PLC	PNR	166.03	79.09	1.16	13.13	13,130.92	0.03%	0.00%	0.41%
Vertex Pharmaceuticals Inc	VRTX	258.46	392.81	n/a	16.71	101,525.28	0.24%	n/a	4.07%
Amcor PLC	AMCR	1445.34	8.94	5.59	2.63	12,921.37	0.03%	0.00%	0.08%
Meta Platforms Inc	META	2191.45	430.17	0.46	18.58	942,694.33	2.26%	0.01%	42.03%
T-Mobile US Inc	TMUS	1171.85	164.17	1.58	5.00	192,383.27	0.46%	0.01%	2.31%
United Rentals Inc	URI	66.59	667.99	0.98	5.27	44,481.45	0.11%	0.00%	0.56%
Alexandria Real Estate Equities Inc	ARE	174.88	115.87	4.38	5.49	20,263.69	0.05%	0.00%	0.27%
Honeywell International Inc	HON	651.19	192.73	2.24	8.50	125,503.08	0.30%	0.01%	2.56%
Delta Air Lines Inc	DAL	645.31	50.07	0.80	12.00	32,310.77	0.08%	0.00%	0.93%
United Airlines Holdings Inc	UAL	328.80	51.46	n/a	12.79	16,920.20	0.04%	n/a	0.52%
Seagate Technology Holdings PLC	STX	209.99	85.91	3.26	1.21	18,040.15	0.04%	0.00%	0.05%
News Corp	NWS	191.10	24.54	0.81	n/a	n/a	n/a	n/a	
Centene Corp	CNC	534.91	73.06	n/a	5.16	39,080.23	0.09%	n/a	0.48%
Martin Marietta Materials Inc	MLM	61.64	587.07	0.50	9.71	36,186.99	0.09%	0.00%	0.84%
Teradyne Inc	TER	152.97	116.32	0.41	-1.44	17,793.94	0.04%	0.00%	-0.06%
PayPal Holdings Inc	PYPL	1046.05	67.92	n/a	6.02	71,047.44	0.17%	n/a	1.03%
Tesla Inc	TSLA	3189.20	183.28	n/a	-11.00	584,515.84	1.40%	n/a	-15.43%
Arch Capital Group Ltd	ACGL	374.15	93.54	n/a	6.00	34,998.08	0.08%	n/a	0.50%
Dow Inc	DOW	703.27	56.90	4.92	2.46	40,015.95	0.10%	0.00%	0.24%
Everest Group Ltd	EG	43.38	366.41	1.91	3.93	15,895.60	0.04%	0.00%	0.15%
Teledyne Technologies Inc	TDY	47.42	381.48	n/a	7.49	18,090.54	0.04%	n/a	0.33%

Name	Ticker	Shares Outst'g	Price	Dividend Yield	Bloomberg Long-Term Growth Estimate	Market Cap Excl. n/a Growth	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
GE Vernova Inc	GEV	274.09	153.71	n/a	n/a	n/a	n/a	n/a	
News Corp	NWSA	380.02	23.80	0.84	n/a	n/a	n/a	n/a	
Exelon Corp	EXC	999.74	37.58	4.04	5.25	37,570.04	0.09%	0.00%	0.47%
Global Payments Inc	GPN	257.99	122.77	0.81	11.98	31,672.82	0.08%	0.00%	0.91%
Crown Castle Inc	CCI	435.00	93.78	6.68	7.00	40,794.30	0.10%	0.01%	0.69%
Aptiv PLC	APTV	272.68	71.00	n/a	11.44	19,360.21	0.05%	n/a	0.53%
Align Technology Inc	ALGN	75.28	282.38	n/a	6.87	21,257.28	0.05%	n/a	0.35%
Illumina Inc	ILMN	158.90	123.05	n/a	3.00	19,552.65	0.05%	n/a	0.14%
Kenvue Inc	KVUE	1914.65	18.82	4.25	15.35	36,033.68	0.09%	0.00%	1.33%
Targa Resources Corp	TRGP	223.16	114.06	2.63	9.00	25,453.06	0.06%	0.00%	0.55%
Bunge Global SA	BG	141.60	101.76	2.60	-8.30	14,408.71	0.03%	0.00%	-0.29%
LKQ Corp	LKQ	266.78	43.13	2.78	n/a	n/a	n/a	n/a	
Deckers Outdoor Corp	DECK	25.67	818.47	n/a	19.98	21,008.49	0.05%	n/a	1.01%
Zoetis Inc	ZTS	456.95	159.24	1.09	10.10	72,764.24	0.17%	0.00%	1.76%
Equinix Inc	EQIX	94.91	711.11	2.40	12.49	67,487.89	0.16%	0.00%	2.02%
Digital Realty Trust Inc	DLR	311.61	138.78	3.52	4.80	43,244.96	0.10%	0.00%	0.50%
Molina Healthcare Inc	MOH	59.00	342.10	n/a	11.72	20,183.90	0.05%	n/a	0.57%
Las Vegas Sands Corp	LVS	745.05	44.36	1.80	n/a	n/a	n/a	n/a	

MARKET RISK PREMIUM CALCULATION USING CAP. WEIGHTED VALUE LINE GROWTH RATES

[7] Cap. Weighted Estimate of the S&P 500 Dividend Yield	1.49%
[8] Cap. Weighted Estimate of the S&P 500 Growth Rate	12.61%
[9] Cap. Weighted S&P 500 Estimated Required Market Return	14.20%

Notes:
[7] Source: Bloomberg Professional, as of April 30, 2024
[8] Source: Value Line, as of April 30, 2024
[9] Equals ([7] x (1 + (0.5 x [8]))) + [8]

Name	Ticker	Shares Outst'g	Price	Dividend Yield	Value Line Long-Term Growth Estimate	Market Cap Excl. n/a Growth	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
LyondellBasell Industries NV	LYB	325.62	99.97	5.00	0.00	32,552.43	0.08%	0.39%	0.00%
American Express Co	AXP	719.30	234.03	1.20	9.00	168,338.48	0.40%	0.48%	3.63%
Verizon Communications Inc	VZ	4209.26	39.49	6.74	1.50	166,223.48	0.40%	2.68%	0.60%
Broadcom Inc	AVGO	463.42	1300.27	1.62	30.00	602,572.42	1.44%	2.33%	43.31%
Boeing Co/The	BA	613.88	167.84	n/a		0.00	0.00%		
Solventum Corp	SOLV	172.71	65.01	n/a		0.00	0.00%		
Caterpillar Inc	CAT	489.05	334.57	1.55	13.00	163,622.46	0.39%	0.61%	5.10%
JPMorgan Chase & Co	JPM	2872.09	191.74	2.40	7.00	550,694.73	1.32%	3.17%	9.24%
Chevron Corp	CVX	1847.32	161.27	4.04	16.50	297,917.30	0.71%	2.89%	11.78%
Coca-Cola Co/The	KO	4311.19	61.77	3.14	7.00	266,302.27	0.64%	2.00%	4.47%
AbbVie Inc	ABBV	1770.65	162.64	3.81	4.00	287,978.03	0.69%	2.63%	2.76%
Walt Disney Co/The	DIS	1834.33	111.10	0.81	21.50	203,793.95	0.49%	0.40%	10.50%
Corpay Inc	CPAY	71.85	302.14	n/a	14.00	21,709.97	0.05%		0.73%
Extra Space Storage Inc	EXR	211.62	134.28	4.83	5.00	28,416.33	0.07%	0.33%	0.34%
Exxon Mobil Corp	XOM	3943.01	118.27	3.21	8.00	466,339.44	1.12%	3.59%	8.94%
Phillips 66	PSX	423.95	143.21	3.21	17.50	60,714.17	0.15%	0.47%	2.55%
General Electric Co	GE	1094.61	161.82	0.69	24.00	177,129.30	0.42%	0.29%	10.19%
HP Inc	HPQ	978.48	28.09	3.92	12.50	27,485.53	0.07%	0.26%	0.82%
Home Depot Inc/The	HD	991.03	334.22	2.69	6.50	331,222.38	0.79%	2.14%	5.16%
Monolithic Power Systems Inc	MPWR	48.66	669.33	0.75	10.50	32,570.27	0.08%	0.06%	0.82%
International Business Machines Corp	IBM	918.60	166.20	4.02	3.00	152,671.82	0.37%	1.47%	1.10%
Johnson & Johnson	JNJ	2409.78	144.59	3.43	4.50	348,430.52	0.83%	2.86%	3.76%
Lululemon Athletica Inc	LULU	120.89	360.60	n/a	16.00	43,593.66	0.10%		1.67%
McDonald's Corp	MCD	721.01	273.04	2.45	10.00	196,863.21	0.47%	1.15%	4.72%
Merck & Co Inc	MRK	2533.03	129.22	2.38	15.50	327,317.88	0.78%	1.87%	12.16%
3M Co	MMM	553.36	96.51	6.26	30.50	53,404.87	0.13%	0.80%	3.90%
American Water Works Co Inc	AWK	194.76	122.32	2.31	3.00	23,822.43	0.06%	0.13%	0.17%
Bank of America Corp	BAC	7820.37	37.01	2.59	5.00	289,431.89	0.69%	1.80%	3.47%
Pfizer Inc	PFE	5646.78	25.62	6.56	2.50	144,670.45	0.35%	2.27%	0.87%
Procter & Gamble Co/The	PG	2360.14	163.20	2.47	6.00	385,174.03	0.92%	2.28%	5.54%
AT&T Inc	T	7170.00	16.89	6.57	2.00	121,101.30	0.29%	1.91%	0.58%
Travelers Cos Inc/The	TRV	228.99	212.16	1.98	10.50	48,583.15	0.12%	0.23%	1.22%
RTX Corp	RTX	1329.51	101.52	2.32	12.00	134,971.45	0.32%	0.75%	3.88%
Analog Devices Inc	ADI	495.91	200.61	1.83	11.50	99,484.10	0.24%	0.44%	2.74%
Walmart Inc	WMT	8058.05	59.35	1.40	7.00	478,245.21	1.15%	1.60%	8.02%
Cisco Systems Inc	CSCO	4049.19	46.98	3.41	4.50	190,230.81	0.46%	1.55%	2.05%
Intel Corp	INTC	4256.87	30.47	1.64	6.00	129,706.89	0.31%	0.51%	1.86%
General Motors Co	GM	1140.40	44.53	1.08	8.50	50,781.79	0.12%	0.13%	1.03%
Microsoft Corp	MSFT	7432.31	389.33	0.77	14.00	2,893,619.69	6.93%	5.34%	97.06%
Dollar General Corp	DG	219.67	139.19	1.70	3.50	30,576.01	0.07%	0.12%	0.26%
Cigna Group/The	CI	283.65	357.04	1.57	12.00	101,273.32	0.24%	0.38%	2.91%
Kinder Morgan Inc	KMI	2219.38	18.28	6.29	15.00	40,570.34	0.10%	0.61%	1.46%
Citigroup Inc	C	1911.37	61.33	3.46	2.50	117,224.14	0.28%	0.97%	0.70%
American International Group Inc	AIG	674.03	75.31	1.91	11.50	50,761.35	0.12%	0.23%	1.40%
Altria Group Inc	MO	1717.63	43.81	8.95	6.00	75,249.20	0.18%	1.61%	1.08%
HCA Healthcare Inc	HCA	264.49	309.82	0.85	10.00	81,942.74	0.20%	0.17%	1.96%
International Paper Co	IP	347.33	34.94	5.29	6.00	12,135.78	0.03%	0.15%	0.17%
Hewlett Packard Enterprise Co	HPE	1300.00	17.00	3.06	7.50	22,100.00	0.05%	0.16%	0.40%
Abbott Laboratories	ABT	1735.18	105.97	2.08	4.00	183,877.45	0.44%	0.91%	1.76%
Aflac Inc	AFL	575.41	83.65	2.39	7.50	48,132.88	0.12%	0.28%	0.86%
Air Products and Chemicals Inc	APD	222.31	236.34	3.00	10.50	52,539.80	0.13%	0.38%	1.32%
Super Micro Computer Inc	SMCI	58.55	858.80	n/a	39.00	50,282.74	0.12%		4.70%
Royal Caribbean Cruises Ltd	RCL	257.35	139.63	n/a		0.00	0.00%		
Hess Corp	HES	308.11	157.49	1.11	19.50	48,524.09	0.12%	0.13%	2.27%
Archer-Daniels-Midland Co	ADM	494.44	58.66	3.41	7.50	29,003.73	0.07%	0.24%	0.52%
Automatic Data Processing Inc	ADP	410.79	241.89	2.32	10.50	99,366.23	0.24%	0.55%	2.50%
Verisk Analytics Inc	VRSK	143.39	217.96	0.72	8.00	31,253.28	0.07%	0.05%	0.60%
AutoZone Inc	AZO	17.30	2956.40	n/a	12.50	51,154.59	0.12%		1.53%
Linde PLC	LIN	481.58	440.96	1.26	8.50	212,355.75	0.51%	0.64%	4.32%
Avery Dennison Corp	AVY	80.55	217.28	1.62	9.50	17,502.56	0.04%	0.07%	0.40%
Enphase Energy Inc	ENPH	136.06	108.76	n/a	14.00	14,798.21	0.04%		0.50%
MSCI Inc	MSCI	79.22	465.79	1.37	12.50	36,901.75	0.09%	0.12%	1.11%
Ball Corp	BALL	315.64	69.57	1.15	10.50	21,959.21	0.05%	0.06%	0.55%
Axon Enterprise Inc	AXON	75.46	313.66	n/a	21.50	23,669.72	0.06%		1.22%
Dayforce Inc	DAY	156.60	61.37	n/a		0.00	0.00%		

Name	Ticker	Shares Outst'g	Price	Dividend Yield	Value Line Long-Term Growth Estimate	Market Cap Excl. n/a Growth	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
Carrier Global Corp	CARR	901.01	61.49	1.24	14.00	55,403.23	0.13%	0.16%	1.86%
Bank of New York Mellon Corp/The	BK	747.82	56.49	2.97	7.00	42,244.13	0.10%	0.30%	0.71%
Otis Worldwide Corp	OTIS	404.32	91.20	1.71	12.00	36,874.26	0.09%	0.15%	1.06%
Baxter International Inc	BAX	508.00	40.37	2.87	4.00	20,507.96	0.05%	0.14%	0.20%
Becton Dickinson & Co	BDX	288.90	234.60	1.62	5.50	67,776.41	0.16%	0.26%	0.89%
Berkshire Hathaway Inc	BRK/B	1311.00	396.73	n/a	6.00	520,111.05	1.25%		7.48%
Best Buy Co Inc	BBY	215.38	73.64	5.11	0.00	15,860.66	0.04%	0.19%	0.00%
Boston Scientific Corp	BSX	1469.90	71.87	n/a	15.00	105,641.35	0.25%		3.80%
Bristol-Myers Squibb Co	BMY	2027.10	43.94	5.46		0.00	0.00%	0.00%	
Brown-Forman Corp	BF/B	303.42	47.85	1.82	15.50	14,518.46	0.03%	0.06%	0.54%
Coterra Energy Inc	CTRA	751.85	27.36	3.07		0.00	0.00%	0.00%	
Campbell Soup Co	CPB	298.10	45.71	3.24	5.00	13,626.29	0.03%	0.11%	0.16%
Hilton Worldwide Holdings Inc	HLT	250.05	197.28	0.30		0.00	0.00%	0.00%	
Carnival Corp	CCL	1119.45	14.82	n/a		0.00	0.00%		
Qorvo Inc	QRVO	96.55	116.84	n/a	9.50	11,280.67	0.03%		0.26%
Builders FirstSource Inc	BLDR	121.94	182.82	n/a	11.00	22,293.07	0.05%		0.59%
UDR Inc	UDR	329.33	38.08	4.46	2.50	12,540.85	0.03%	0.13%	0.08%
Clorox Co/The	CLX	124.19	147.87	3.25	9.50	18,363.68	0.04%	0.14%	0.42%
Paycom Software Inc	PAYC	58.15	187.98	0.80	21.00	10,931.04	0.03%	0.02%	0.55%
CMS Energy Corp	CMS	291.76	60.61	3.40	5.00	17,683.82	0.04%	0.14%	0.21%
Colgate-Palmolive Co	CL	820.44	91.92	2.18	8.00	75,414.94	0.18%	0.39%	1.45%
EPAM Systems Inc	EPAM	58.00	235.26	n/a	20.50	13,643.90	0.03%		0.67%
Comerica Inc	CMA	132.59	50.17	5.66	0.50	6,651.89	0.02%	0.09%	0.01%
Conagra Brands Inc	CAG	478.06	30.78	4.55	3.50	14,714.78	0.04%	0.16%	0.12%
Airbnb Inc	ABNB	438.09	158.57	n/a	23.00	69,467.46	0.17%		3.83%
Consolidated Edison Inc	ED	344.92	94.40	3.52	6.00	32,560.83	0.08%	0.27%	0.47%
Corning Inc	GLW	855.35	33.38	3.36	17.50	28,551.65	0.07%	0.23%	1.20%
Cummins Inc	CMI	141.86	282.49	2.38	7.50	40,073.18	0.10%	0.23%	0.72%
Caesars Entertainment Inc	CZR	216.42	35.82	n/a		0.00	0.00%		
Danaher Corp	DHR	740.69	246.62	0.44	7.00	182,668.23	0.44%	0.19%	3.06%
Target Corp	TGT	461.69	160.98	2.73	11.00	74,322.86	0.18%	0.49%	1.96%
Deere & Co	DE	278.36	391.41	1.50	5.00	108,952.10	0.26%	0.39%	1.31%
Dominion Energy Inc	D	837.59	50.98	5.24	0.50	42,700.49	0.10%	0.54%	0.05%
Dover Corp	DOV	137.43	179.30	1.14	6.00	24,641.20	0.06%	0.07%	0.35%
Alliant Energy Corp	LNT	252.72	49.80	3.86	6.50	12,585.41	0.03%	0.12%	0.20%
Steel Dynamics Inc	STLD	160.02	130.12	1.41	2.00	20,821.54	0.05%	0.07%	0.10%
Duke Energy Corp	DUK	771.00	98.26	4.17	5.00	75,758.46	0.18%	0.76%	0.91%
Regency Centers Corp	REG	184.58	59.22	4.53	14.50	10,930.89	0.03%	0.12%	0.38%
Eaton Corp PLC	ETN	399.89	318.26	1.18	12.50	127,269.63	0.30%	0.36%	3.81%
Ecolab Inc	ECL	285.91	226.15	1.01	7.00	64,659.00	0.15%	0.16%	1.08%
Revvity Inc	RVTY	123.53	102.47	0.27	-2.50	12,657.61	0.03%	0.01%	-0.08%
Emerson Electric Co	EMR	571.70	107.78	1.95	7.00	61,617.83	0.15%	0.29%	1.03%
EOG Resources Inc	EOG	580.00	132.13	2.75	15.00	76,635.66	0.18%	0.51%	2.75%
Aon PLC	AON	217.43	282.01	0.96	10.50	61,317.72	0.15%	0.14%	1.54%
Entergy Corp	ETR	213.27	106.67	4.24	0.50	22,749.83	0.05%	0.23%	0.03%
Equifax Inc	EFX	123.61	220.19	0.71	5.50	27,217.91	0.07%	0.05%	0.36%
EQT Corp	EQT	441.59	40.09	1.57		0.00	0.00%	0.00%	
IQVIA Holdings Inc	IQV	182.01	231.77	n/a	11.50	42,185.38	0.10%		1.16%
Gartner Inc	IT	77.63	412.59	n/a	7.50	32,029.36	0.08%		0.58%
FedEx Corp	FDX	246.08	261.78	1.93	7.00	64,419.08	0.15%	0.30%	1.08%
FMC Corp	FMC	124.82	59.01	3.93	5.00	7,365.45	0.02%	0.07%	0.09%
Brown & Brown Inc	BRO	285.25	81.54	0.64	9.00	23,259.20	0.06%	0.04%	0.50%
Ford Motor Co	F	3921.49	12.15	4.94	37.00	47,646.04	0.11%	0.56%	4.22%
NextEra Energy Inc	NEE	2023.71	66.97	3.08	8.50	135,528.13	0.32%	1.00%	2.76%
Franklin Resources Inc	BEN	526.09	22.84	5.43	2.00	12,015.92	0.03%	0.16%	0.06%
Garmin Ltd	GRMN	192.08	144.47	2.08	5.00	27,749.65	0.07%	0.14%	0.33%
Freeport-McMoRan Inc	FCX	1434.41	49.94	1.20	12.50	71,634.39	0.17%	0.21%	2.15%
Dexcom Inc	DXCM	397.68	127.39	n/a		0.00	0.00%		
General Dynamics Corp	GD	274.36	287.09	1.98	10.00	78,767.16	0.19%	0.37%	1.89%
General Mills Inc	GIS	564.55	70.46	3.35	5.50	39,778.12	0.10%	0.32%	0.52%
Genuine Parts Co	GPC	139.30	157.21	2.54	9.00	21,899.20	0.05%	0.13%	0.47%
Atmos Energy Corp	ATO	150.84	117.90	2.73	7.00	17,784.04	0.04%	0.12%	0.30%
WW Grainger Inc	GWW	49.07	921.35	0.89	7.00	45,209.72	0.11%	0.10%	0.76%
Halliburton Co	HAL	885.30	37.47	1.81	20.50	33,172.23	0.08%	0.14%	1.63%
Healthpeak Properties Inc	DOC	703.78	18.61	6.45	18.50	13,097.38	0.03%	0.20%	0.58%
L3Harris Technologies Inc	LHX	189.68	214.05	2.17	10.50	40,601.00	0.10%	0.21%	1.02%
Insulet Corp	PODD	70.02	171.94	n/a		0.00	0.00%		
Catalent Inc	CTLT	180.97	55.85	n/a	21.00	10,107.40	0.02%		0.51%
Fortive Corp	FTV	352.03	75.27	0.43	15.00	26,497.22	0.06%	0.03%	0.95%
Hershey Co/The	HSY	149.60	193.92	2.83	7.00	29,010.04	0.07%	0.20%	0.49%
Synchrony Financial	SYF	401.54	43.98	2.27	47.00	17,659.91	0.04%	0.10%	1.99%
Hormel Foods Corp	HRL	547.69	35.56	3.18	7.50	19,475.79	0.05%	0.15%	0.35%
Arthur J Gallagher & Co	AJG	216.80	234.69	1.02	22.00	50,880.79	0.12%	0.12%	2.68%
Mondelez International Inc	MDLZ	1341.36	71.94	2.36	10.50	96,497.37	0.23%	0.55%	2.43%
CenterPoint Energy Inc	CNP	633.03	29.14	2.75	8.50	18,446.55	0.04%	0.12%	0.38%
Humana Inc	HUM	120.50	302.09	1.17	8.50	36,402.15	0.09%	0.10%	0.74%
Willis Towers Watson PLC	WTW	102.24	251.14	1.40	10.00	25,675.55	0.06%	0.09%	0.62%
Illinois Tool Works Inc	ITW	298.75	244.11	2.29	9.00	72,926.64	0.17%	0.40%	1.57%
CDW Corp/DE	CDW	134.37	241.86	1.03	7.00	32,498.24	0.08%	0.08%	0.55%
Trane Technologies PLC	TT	226.35	317.34	1.06	12.50	71,830.54	0.17%	0.18%	2.15%
Interpublic Group of Cos Inc/The	IPG	377.42	30.44	4.34	8.50	11,488.79	0.03%	0.12%	0.23%
International Flavors & Fragrances Inc	IFF	255.32	84.65	1.89	0.50	21,612.75	0.05%	0.10%	0.03%
Generac Holdings Inc	GNRC	60.27	135.96	n/a	12.50	8,194.17	0.02%		0.25%
NXP Semiconductors NV	NXPI	255.68	256.19	1.58	10.00	65,503.68	0.16%	0.25%	1.57%

Name	Ticker	Shares Outst'g	Price	Dividend Yield	Value Line Long-Term Growth Estimate	Market Cap Excl. n/a Growth	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
Kellanova	K	340.68	57.86	3.87		0.00	0.00%	0.00%	
Broadridge Financial Solutions Inc	BR	117.77	193.41	1.65	9.50	22,778.28	0.05%	0.09%	0.52%
Kimberly-Clark Corp	KMB	336.71	136.53	3.57	7.50	45,970.88	0.11%	0.39%	0.83%
Kimco Realty Corp	KIM	674.13	18.63	5.15	18.00	12,559.10	0.03%	0.16%	0.54%
Oracle Corp	ORCL	2748.51	113.75	1.41	10.00	312,643.47	0.75%	1.05%	7.49%
Kroger Co/The	KR	721.69	55.38	2.09	6.00	39,967.08	0.10%	0.20%	0.57%
Lennar Corp	LEN	245.04	151.62	1.32	5.00	37,152.36	0.09%	0.12%	0.45%
Eli Lilly & Co	LLY	950.41	781.10	0.67	27.50	742,361.35	1.78%	1.18%	48.91%
Bath & Body Works Inc	BBWI	224.90	45.42	1.76	26.50	10,214.82	0.02%	0.04%	0.65%
Charter Communications Inc	CHTR	144.39	255.94	n/a	8.50	36,954.15	0.09%		0.75%
Loews Corp	L	222.07	75.15	0.33	12.00	16,688.71	0.04%	0.01%	0.48%
Lowe's Cos Inc	LOW	572.19	227.99	1.93	6.50	130,454.05	0.31%	0.60%	2.03%
Hubbell Inc	HUBB	53.68	370.52	1.32	9.00	19,890.63	0.05%	0.06%	0.43%
IDEX Corp	IEX	75.70	220.46	1.16	8.00	16,687.72	0.04%	0.05%	0.32%
Marsh & McLennan Cos Inc	MMC	492.72	199.43	1.42	11.00	98,263.95	0.24%	0.34%	2.59%
Masco Corp	MAS	220.24	68.45	1.69	6.00	15,075.70	0.04%	0.06%	0.22%
S&P Global Inc	SPGI	320.26	415.83	0.88	7.50	133,172.47	0.32%	0.28%	2.39%
Medtronic PLC	MDT	1327.82	80.24	3.44	6.50	106,544.52	0.26%	0.88%	1.66%
Viatris Inc	VTRS	1187.57	11.57	4.15		0.00	0.00%	0.00%	
CVS Health Corp	CVS	1260.48	67.71	3.93	5.00	85,347.10	0.20%	0.80%	1.02%
DuPont de Nemours Inc	DD	417.58	72.50	2.10	9.00	30,274.77	0.07%	0.15%	0.65%
Micron Technology Inc	MU	1107.37	112.96	0.41	19.50	125,088.29	0.30%	0.12%	5.84%
Motorola Solutions Inc	MSI	166.12	339.15	1.16	10.50	56,340.62	0.13%	0.16%	1.42%
Cboe Global Markets Inc	CBOE	105.58	181.15	1.21	15.00	19,126.18	0.05%	0.06%	0.69%
Laboratory Corp of America Holdings	LH	84.29	201.37	1.43	-2.00	16,974.28	0.04%	0.06%	-0.08%
Newmont Corp	NEM	1153.14	40.64	2.46	5.00	46,863.61	0.11%	0.28%	0.56%
NIKE Inc	NKE	1211.46	92.26	1.60	17.00	111,769.48	0.27%	0.43%	4.55%
NiSource Inc	NI	448.19	27.86	3.80	9.50	12,486.52	0.03%	0.11%	0.28%
Norfolk Southern Corp	NSC	225.91	230.32	2.34	7.50	52,032.51	0.12%	0.29%	0.93%
Principal Financial Group Inc	PFG	235.15	79.14	3.59	4.00	18,609.77	0.04%	0.16%	0.18%
Eversource Energy	ES	350.73	60.62	4.72	5.50	21,261.07	0.05%	0.24%	0.28%
Northrop Grumman Corp	NOC	147.99	485.03	1.54	8.00	71,779.59	0.17%	0.27%	1.38%
Wells Fargo & Co	WFC	3501.70	59.32	2.36	9.50	207,720.84	0.50%	1.17%	4.73%
Nucor Corp	NUE	239.98	168.53	1.28	2.00	40,443.83	0.10%	0.12%	0.19%
Occidental Petroleum Corp	OXY	879.50	66.14	1.33	15.50	58,170.06	0.14%	0.19%	2.16%
Omnicom Group Inc	OMC	195.83	92.84	3.02	7.00	18,181.23	0.04%	0.13%	0.30%
ONEOK Inc	OKE	583.64	79.12	5.01	15.00	46,177.60	0.11%	0.55%	1.66%
Raymond James Financial Inc	RJF	207.30	122.00	1.48	15.00	25,290.60	0.06%	0.09%	0.91%
PG&E Corp	PCG	2133.51	17.11	0.23	9.00	36,504.32	0.09%	0.02%	0.79%
Parker-Hannifin Corp	PH	128.41	544.91	1.20	11.50	69,972.44	0.17%	0.20%	1.93%
Rollins Inc	ROL	484.23	44.56	1.35	9.00	21,577.29	0.05%	0.07%	0.47%
PPL Corp	PPL	737.12	27.46	3.75	7.50	20,241.43	0.05%	0.18%	0.36%
ConocoPhillips	COP	1171.10	125.62	2.48	4.00	147,113.71	0.35%	0.88%	1.41%
PulteGroup Inc	PHM	210.34	111.42	0.72	6.50	23,436.31	0.06%	0.04%	0.36%
Pinnacle West Capital Corp	PNW	113.56	73.65	4.78	4.50	8,363.47	0.02%	0.10%	0.09%
PNC Financial Services Group Inc/The	PNC	397.85	153.26	4.05	6.50	60,973.72	0.15%	0.59%	0.95%
PPG Industries Inc	PPG	235.36	129.00	2.02	9.00	30,361.57	0.07%	0.15%	0.65%
Progressive Corp/The	PGR	585.70	208.25	0.19	14.50	121,972.03	0.29%	0.06%	4.24%
Veralto Corp	VLTO	246.85	93.68	0.38		0.00	0.00%	0.00%	
Public Service Enterprise Group Inc	PEG	498.59	69.08	3.47	4.00	34,442.39	0.08%	0.29%	0.33%
Robert Half Inc	RHI	105.12	69.14	3.07	7.00	7,267.79	0.02%	0.05%	0.12%
Cooper Cos Inc/The	COO	198.76	89.06	n/a	9.50	17,701.21	0.04%		0.40%
Edison International	EIX	383.93	71.06	4.39	6.00	27,281.71	0.07%	0.29%	0.39%
Schlumberger NV	SLB	1429.34	47.48	2.32	21.50	67,864.97	0.16%	0.38%	3.50%
Charles Schwab Corp/The	SCHW	1773.48	73.95	1.35	10.50	131,148.48	0.31%	0.42%	3.30%
Sherwin-Williams Co/The	SHW	253.55	299.61	0.95	11.00	75,965.82	0.18%	0.17%	2.00%
West Pharmaceutical Services Inc	WST	72.84	357.48	0.22	7.50	26,039.92	0.06%	0.01%	0.47%
J M Smucker Co/The	SJM	106.18	114.85	3.69	7.00	12,194.31	0.03%	0.11%	0.20%
Snap-on Inc	SNA	52.72	267.96	2.78	6.00	14,126.58	0.03%	0.09%	0.20%
AMETEK Inc	AME	231.21	174.66	0.64	10.00	40,383.31	0.10%	0.06%	0.97%
Uber Technologies Inc	UBER	2081.54	66.27	n/a		0.00	0.00%		
Southern Co/The	SO	1094.63	73.50	3.92	6.50	80,455.53	0.19%	0.76%	1.25%
Truist Financial Corp	TFC	1338.10	37.55	5.54	1.50	50,245.50	0.12%	0.67%	0.18%
Southwest Airlines Co	LUV	598.46	25.94	2.78		0.00	0.00%	0.00%	
W R Berkley Corp	WRB	256.55	76.97	0.57	15.00	19,746.58	0.05%	0.03%	0.71%
Stanley Black & Decker Inc	SWK	153.80	91.40	3.54	1.00	14,057.50	0.03%	0.12%	0.03%
Public Storage	PSA	175.83	259.45	4.63	7.00	45,618.83	0.11%	0.51%	0.77%
Arista Networks Inc	ANET	312.63	256.56	n/a	10.50	80,209.38	0.19%		2.02%
Sysco Corp	SYY	497.83	74.32	2.74	16.00	36,998.73	0.09%	0.24%	1.42%
Corteva Inc	CTVA	687.80	54.13	1.18	9.00	37,230.45	0.09%	0.11%	0.80%
Texas Instruments Inc	TXN	910.48	176.42	2.95	3.00	160,627.23	0.38%	1.13%	1.15%
Textron Inc	TXT	190.70	84.59	0.09	16.00	16,131.23	0.04%	0.00%	0.62%
Thermo Fisher Scientific Inc	TMO	381.31	568.72	0.27	6.50	216,859.76	0.52%	0.14%	3.38%
TJX Cos Inc/The	TJX	1132.97	94.09	1.59	17.00	106,601.52	0.26%	0.41%	4.34%
Globe Life Inc	GL	94.04	76.17	1.26	8.00	7,162.80	0.02%	0.02%	0.14%
Johnson Controls International plc	JCI	681.48	65.07	2.27	9.50	44,343.71	0.11%	0.24%	1.01%
Ulta Beauty Inc	ULTA	47.94	404.84	n/a	8.00	19,406.01	0.05%		0.37%
Union Pacific Corp	UNP	610.12	237.16	2.19	6.00	144,696.53	0.35%	0.76%	2.08%
Keysight Technologies Inc	KEYS	174.56	147.94	n/a	13.00	25,823.81	0.06%		0.80%
UnitedHealth Group Inc	UNH	920.08	483.70	1.55	13.00	445,042.70	1.07%	1.66%	13.86%
Blackstone Inc	BX	722.26	116.61	2.85	16.00	84,223.09	0.20%	0.57%	3.23%
Marathon Oil Corp	MRO	571.48	26.85	1.64	13.50	15,344.16	0.04%	0.06%	0.50%
Bio-Rad Laboratories Inc	BIO	23.42	269.75	n/a	11.50	6,318.35	0.02%		0.17%
Ventas Inc	VTR	404.05	44.28	4.07	23.00	17,891.29	0.04%	0.17%	0.99%

Name	Ticker	Shares Outst'g	Price	Dividend Yield	Value Line Long-Term Growth Estimate	Market Cap Excl. n/a Growth	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
Vulcan Materials Co	VMC	132.27	257.63	0.71	8.00	34,077.24	0.08%	0.06%	0.65%
Weyerhaeuser Co	WY	729.62	30.17	2.65	-1.00	22,012.54	0.05%	0.14%	-0.05%
Williams Cos Inc/The	WMB	1218.43	38.36	4.95	10.00	46,738.78	0.11%	0.55%	1.12%
Constellation Energy Corp	CEG	315.12	185.94	0.76		0.00	0.00%	0.00%	
WEC Energy Group Inc	WEC	315.56	82.64	4.04	6.00	26,078.04	0.06%	0.25%	0.37%
Adobe Inc	ADBE	448.00	462.83	n/a	13.50	207,347.84	0.50%		6.71%
AES Corp/The	AES	710.29	17.90	3.85	14.00	12,714.14	0.03%	0.12%	0.43%
Expeditors International of Washington Inc	EXPD	143.90	111.31	1.24	-1.00	16,017.40	0.04%	0.05%	-0.04%
Amgen Inc	AMGN	536.38	273.94	3.29	5.00	146,934.84	0.35%	1.16%	1.76%
Apple Inc	AAPL	15441.88	170.33	0.56	6.50	2,630,215.59	6.30%	3.55%	40.96%
Autodesk Inc	ADSK	213.92	212.85	n/a	10.00	45,531.81	0.11%		1.09%
Cintas Corp	CTAS	101.46	658.34	0.82	14.00	66,797.15	0.16%	0.13%	2.24%
Comcast Corp	CMCSA	3914.18	38.11	3.25	8.00	149,169.48	0.36%	1.16%	2.86%
Molson Coors Beverage Co	TAP	197.55	57.26	3.07	11.50	11,311.77	0.03%	0.08%	0.31%
KLA Corp	KLAC	134.64	689.29	0.84	10.50	92,806.01	0.22%	0.19%	2.33%
Marriott International Inc/MD	MAR	288.26	236.13	0.88	11.00	68,066.60	0.16%	0.14%	1.79%
Fiserv Inc	FI	585.10	152.67	n/a	9.50	89,327.52	0.21%		2.03%
McCormick & Co Inc/MD	MKC	251.75	76.06	2.21	4.50	19,147.72	0.05%	0.10%	0.21%
PACCAR Inc	PCAR	524.01	106.11	1.13	5.00	55,602.81	0.13%	0.15%	0.67%
Costco Wholesale Corp	COST	443.50	722.90	0.64	9.00	320,609.04	0.77%	0.49%	6.91%
Stryker Corp	SYK	380.47	336.50	0.95	10.00	128,028.16	0.31%	0.29%	3.07%
Tyson Foods Inc	TSN	286.34	60.65	3.23	6.00	17,366.46	0.04%	0.13%	0.25%
Lamb Weston Holdings Inc	LW	144.39	83.34	1.73	14.50	12,033.55	0.03%	0.05%	0.42%
Applied Materials Inc	AMAT	830.90	198.65	0.81	7.50	165,057.69	0.40%	0.32%	2.97%
American Airlines Group Inc	AAL	653.54	13.51	n/a		0.00	0.00%		
Cardinal Health Inc	CAH	243.23	103.04	1.94	6.50	25,062.73	0.06%	0.12%	0.39%
Cincinnati Financial Corp	CINF	156.56	115.69	2.80	10.50	18,112.20	0.04%	0.12%	0.46%
Paramount Global	PARA	625.78	11.39	1.76	-2.50	7,127.59	0.02%	0.03%	-0.04%
DR Horton Inc	DHI	329.31	142.49	0.84	4.00	46,923.67	0.11%	0.09%	0.45%
Electronic Arts Inc	EA	267.35	126.82	0.60	16.50	33,905.33	0.08%	0.05%	1.34%
Fair Isaac Corp	FICO	24.71	1133.33	n/a	19.50	28,005.72	0.07%		1.31%
Fastenal Co	FAST	572.55	67.94	2.30	9.00	38,898.84	0.09%	0.21%	0.84%
M&T Bank Corp	MTB	166.72	144.39	3.60		0.00	0.00%	0.00%	
Xcel Energy Inc	XEL	555.64	53.73	4.08	7.00	29,854.48	0.07%	0.29%	0.50%
Fifth Third Bancorp	FITB	683.81	36.46	3.84	4.00	24,931.79	0.06%	0.23%	0.24%
Gilead Sciences Inc	GILD	1246.97	65.20	4.72	8.50	81,302.38	0.19%	0.92%	1.66%
Hasbro Inc	HAS	138.79	61.30	4.57	8.50	8,507.89	0.02%	0.09%	0.17%
Huntington Bancshares Inc/OH	HBAN	1449.25	13.47	4.60	8.00	19,521.45	0.05%	0.22%	0.37%
Welltower Inc	WELL	597.92	95.28	2.56	25.50	56,969.44	0.14%	0.35%	3.48%
Biogen Inc	BIIB	145.60	214.82	n/a	-1.00	31,277.15	0.07%		-0.07%
Northern Trust Corp	NTRS	204.59	82.39	3.64	4.00	16,856.33	0.04%	0.15%	0.16%
Packaging Corp of America	PKG	89.76	172.98	2.89	9.00	15,525.82	0.04%	0.11%	0.33%
Paychex Inc	PAYX	359.96	118.81	3.00	9.00	42,767.20	0.10%	0.31%	0.92%
QUALCOMM Inc	QCOM	1116.00	165.85	2.05	7.50	185,088.60	0.44%	0.91%	3.33%
Ross Stores Inc	ROST	335.17	129.55	1.13	14.00	43,421.79	0.10%	0.12%	1.46%
IDEXX Laboratories Inc	IDXX	83.09	492.76	n/a	11.00	40,942.94	0.10%		1.08%
Starbucks Corp	SBUX	1132.20	88.49	2.58	9.00	100,188.38	0.24%	0.62%	2.16%
KeyCorp	KEY	942.78	14.49	5.66		0.00	0.00%	0.00%	
Fox Corp	FOXA	239.30	31.01	1.68	13.50	7,420.54	0.02%	0.03%	0.24%
Fox Corp	FOX	235.58	28.68	1.81		0.00	0.00%	0.00%	
State Street Corp	STT	301.50	72.49	3.81		0.00	0.00%	0.00%	
Norwegian Cruise Line Holdings Ltd	NCLH	425.66	18.92	n/a		0.00	0.00%		
US Bancorp	USB	1558.00	40.63	4.82	4.50	63,301.54	0.15%	0.73%	0.68%
A O Smith Corp	AOS	120.78	82.84	1.55	11.50	10,005.75	0.02%	0.04%	0.28%
Gen Digital Inc	GEN	636.91	20.14	2.48	10.50	12,827.37	0.03%	0.08%	0.32%
T Rowe Price Group Inc	TROW	223.30	109.57	4.53	1.50	24,466.98	0.06%	0.27%	0.09%
Waste Management Inc	WM	401.08	208.02	1.44	6.00	83,433.29	0.20%	0.29%	1.20%
Constellation Brands Inc	STZ	182.95	253.46	1.59	6.50	46,371.27	0.11%	0.18%	0.72%
Invesco Ltd	IVZ	449.80	14.17	5.79	3.00	6,373.67	0.02%	0.09%	0.05%
Intuit Inc	INTU	279.98	625.62	0.58	13.50	175,160.46	0.42%	0.24%	5.67%
Morgan Stanley	MS	1627.00	90.84	3.74	7.00	147,796.68	0.35%	1.33%	2.48%
Microchip Technology Inc	MCHP	540.39	91.98	1.96	6.00	49,704.89	0.12%	0.23%	0.71%
Chubb Ltd	CB	406.06	248.64	1.38	16.00	100,963.01	0.24%	0.33%	3.87%
Hologic Inc	HOLX	234.73	75.77	n/a	-1.00	17,785.64	0.04%		-0.04%
Citizens Financial Group Inc	CFG	458.49	34.11	4.93	7.50	15,638.92	0.04%	0.18%	0.28%
Jabil Inc	JBL	120.60	117.36	0.27	15.00	14,153.26	0.03%	0.01%	0.51%
O'Reilly Automotive Inc	ORLY	58.98	1013.26	n/a	10.50	59,764.10	0.14%		1.50%
Allstate Corp/The	ALL	263.76	170.06	2.16	11.00	44,854.86	0.11%	0.23%	1.18%
Equity Residential	EQR	378.94	64.40	4.19	-4.50	24,403.74	0.06%	0.25%	-0.26%
BorgWarner Inc	BWA	230.96	32.77	1.34	6.50	7,568.43	0.02%	0.02%	0.12%
Keurig Dr Pepper Inc	KDP	1355.57	33.70	2.55	10.00	45,682.84	0.11%	0.28%	1.09%
Host Hotels & Resorts Inc	HST	703.60	18.87	4.24	51.00	13,276.93	0.03%	0.13%	1.62%
Incyte Corp	INCY	224.54	52.05	n/a	8.50	11,687.36	0.03%		0.24%
Simon Property Group Inc	SPG	325.77	140.53	5.55	3.50	45,779.90	0.11%	0.61%	0.38%
Eastman Chemical Co	EMN	117.65	94.44	3.43	3.50	11,110.77	0.03%	0.09%	0.09%
AvalonBay Communities Inc	AVB	142.03	189.57	3.59	5.50	26,923.68	0.06%	0.23%	0.35%
Prudential Financial Inc	PRU	359.38	110.48	4.71	3.00	39,704.30	0.10%	0.45%	0.29%
United Parcel Service Inc	UPS	727.84	147.48	4.42	2.50	107,342.14	0.26%	1.14%	0.64%
Walgreens Boots Alliance Inc	WBA	862.71	17.73	5.64	-1.50	15,295.90	0.04%	0.21%	-0.05%
STERIS PLC	STE	98.81	204.56	1.02	10.00	20,213.39	0.05%	0.05%	0.48%
McKesson Corp	MCK	131.41	537.21	0.46	8.00	70,593.69	0.17%	0.08%	1.35%
Lockheed Martin Corp	LMT	239.94	464.93	2.71	9.00	111,554.37	0.27%	0.72%	2.41%
Cencora Inc	COR	199.48	239.05	0.85	8.00	47,686.17	0.11%	0.10%	0.91%
Capital One Financial Corp	COF	382.10	143.43	1.67	5.50	54,804.89	0.13%	0.22%	0.72%

Name	Ticker	Shares Outst'g	Price	Dividend Yield	Value Line Long-Term Growth Estimate	Market Cap Excl. n/a Growth	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
Waters Corp	WAT	59.31	309.04	n/a	10.00	18,329.16	0.04%		0.44%
Nordson Corp	NDSN	57.19	258.19	1.05	8.50	14,766.40	0.04%	0.04%	0.30%
Dollar Tree Inc	DLTR	217.98	118.25	n/a	25.00	25,776.49	0.06%		1.54%
Darden Restaurants Inc	DRI	119.36	153.41	3.42	13.00	18,310.86	0.04%	0.15%	0.57%
Evergy Inc	EVRG	229.75	52.45	4.90	7.50	12,050.18	0.03%	0.14%	0.22%
Match Group Inc	MTCH	268.01	30.82	n/a	13.50	8,260.13	0.02%		0.27%
Domino's Pizza Inc	DPZ	34.88	529.27	1.14	11.50	18,460.94	0.04%	0.05%	0.51%
NVR Inc	NVR	3.17	7438.85	n/a	1.50	23,566.28	0.06%		0.08%
NetApp Inc	NTAP	206.38	102.21	1.96	8.50	21,093.79	0.05%	0.10%	0.43%
Old Dominion Freight Line Inc	ODFL	217.67	181.71	0.57	8.50	39,553.54	0.09%	0.05%	0.81%
DaVita Inc	DVA	87.70	139.01	n/a	11.50	12,191.18	0.03%		0.34%
Hartford Financial Services Group Inc/The	HIG	295.76	96.89	1.94	7.00	28,655.70	0.07%	0.13%	0.48%
Iron Mountain Inc	IRM	293.10	77.52	3.35	5.50	22,720.80	0.05%	0.18%	0.30%
Estee Lauder Cos Inc/The	EL	232.93	146.71	1.80	2.50	34,173.31	0.08%	0.15%	0.20%
Cadence Design Systems Inc	CDNS	272.13	275.63	n/a	12.00	75,008.29	0.18%		2.16%
Tyler Technologies Inc	TYL	42.46	461.55	n/a	8.00	19,595.11	0.05%		0.38%
Universal Health Services Inc	UHS	60.08	170.43	0.47	6.00	10,239.95	0.02%	0.01%	0.15%
Skyworks Solutions Inc	SWKS	160.44	106.59	2.55	1.50	17,101.73	0.04%	0.10%	0.06%
Quest Diagnostics Inc	DGX	111.09	138.18	2.17	2.50	15,350.69	0.04%	0.08%	0.09%
Rockwell Automation Inc	ROK	114.59	270.96	1.85	9.50	31,049.85	0.07%	0.14%	0.71%
Kraft Heinz Co/The	KHC	1215.64	38.61	4.14	4.50	46,935.78	0.11%	0.47%	0.51%
American Tower Corp	AMT	466.98	171.56	3.78	5.50	80,114.23	0.19%	0.73%	1.06%
Regeneron Pharmaceuticals Inc	REGN	107.94	890.66	n/a		0.00	0.00%		
Amazon.com Inc	AMZN	10387.38	175.00	n/a	24.50	1,817,791.68	4.36%		106.71%
Jack Henry & Associates Inc	JKHY	72.87	162.69	1.35	6.50	11,854.89	0.03%	0.04%	0.18%
Ralph Lauren Corp	RL	39.04	163.64	1.83	13.00	6,389.16	0.02%	0.03%	0.20%
Boston Properties Inc	BXP	157.05	61.89	6.33	0.50	9,719.76	0.02%	0.15%	0.01%
Amphenol Corp	APH	600.60	120.77	0.73	13.00	72,534.95	0.17%	0.13%	2.26%
Howmet Aerospace Inc	HWM	410.30	66.75	0.30	17.00	27,387.79	0.07%	0.02%	1.12%
Pioneer Natural Resources Co	PXD	233.62	269.32	3.80	2.50	62,919.35	0.15%	0.57%	0.38%
Valero Energy Corp	VLO	327.00	159.87	2.68	9.50	52,276.85	0.13%	0.34%	1.19%
Synopsys Inc	SNPS	152.54	530.59	n/a	12.50	80,938.32	0.19%		2.42%
Etsy Inc	ETSY	117.06	68.67	n/a	4.50	8,038.78	0.02%		0.09%
CH Robinson Worldwide Inc	CHRW	115.71	71.00	3.44	3.50	8,215.55	0.02%	0.07%	0.07%
Accenture PLC	ACN	670.42	300.91	1.71	8.50	201,736.68	0.48%	0.83%	4.11%
TransDigm Group Inc	TDG	55.61	1248.03	n/a	21.00	69,397.96	0.17%		3.49%
Yum! Brands Inc	YUM	281.50	141.25	1.90	10.50	39,761.88	0.10%	0.18%	1.00%
Prologis Inc	PLD	925.84	102.05	3.76	0.50	94,482.38	0.23%	0.85%	0.11%
FirstEnergy Corp	FE	575.52	38.34	4.43	4.50	22,065.28	0.05%	0.23%	0.24%
VeriSign Inc	VRSN	100.14	169.48	n/a	13.00	16,971.56	0.04%		0.53%
Quanta Services Inc	PWR	145.75	258.56	0.14	15.00	37,684.86	0.09%	0.01%	1.35%
Henry Schein Inc	HSIC	128.48	69.28	n/a	7.50	8,901.16	0.02%		0.16%
Ameren Corp	AEE	266.51	73.87	3.63	6.50	19,687.17	0.05%	0.17%	0.31%
ANSYS Inc	ANSS	87.30	324.88	n/a	8.50	28,362.02	0.07%		0.58%
FactSet Research Systems Inc	FDS	38.12	416.89	0.94	11.00	15,890.18	0.04%	0.04%	0.42%
NVIDIA Corp	NVDA	2500.00	864.02	0.02	33.00	2,160,050.00	5.18%	0.10%	170.79%
Cognizant Technology Solutions Corp	CTSH	497.20	65.68	1.83	8.00	32,656.03	0.08%	0.14%	0.63%
Intuitive Surgical Inc	ISRG	354.71	370.62	n/a	13.50	131,461.14	0.31%		4.25%
Take-Two Interactive Software Inc	TTWO	170.75	142.81	n/a	52.50	24,384.24	0.06%		3.07%
Republic Services Inc	RSG	314.98	191.70	1.12	10.50	60,380.71	0.14%	0.16%	1.52%
eBay Inc	EBAY	518.00	51.54	2.10	7.00	26,697.72	0.06%	0.13%	0.45%
Goldman Sachs Group Inc/The	GS	324.53	426.71	2.58	1.50	138,478.92	0.33%	0.86%	0.50%
SBA Communications Corp	SBAC	108.02	186.12	2.11	22.00	20,104.87	0.05%	0.10%	1.06%
Sempra	SRE	632.15	71.63	3.46	6.00	45,280.90	0.11%	0.38%	0.65%
Moody's Corp	MCO	182.50	370.33	0.92	6.50	67,585.23	0.16%	0.15%	1.05%
ON Semiconductor Corp	ON	430.23	70.16	n/a	8.50	30,185.08	0.07%		0.61%
Booking Holdings Inc	BKNG	34.17	3452.03	1.01	22.00	117,959.32	0.28%	0.29%	6.22%
F5 Inc	FFIV	58.81	165.31	n/a	10.00	9,721.22	0.02%		0.23%
Akamai Technologies Inc	AKAM	153.21	100.93	n/a	5.00	15,463.59	0.04%		0.19%
Charles River Laboratories International Inc	CRL	51.35	229.00	n/a	7.00	11,759.15	0.03%		0.20%
MarketAxess Holdings Inc	MKTX	37.87	200.09	1.48	10.00	7,577.01	0.02%	0.03%	0.18%
Devon Energy Corp	DVN	635.00	51.18	3.44	9.50	32,499.30	0.08%	0.27%	0.74%
Bio-Techne Corp	TECH	157.19	63.21	0.51	11.00	9,936.11	0.02%	0.01%	0.26%
Alphabet Inc	GOOGL	5874.00	162.78	0.49		0.00	0.00%	0.00%	
Teleflex Inc	TFX	47.10	208.75	0.65	9.00	9,832.33	0.02%	0.02%	0.21%
Allegion plc	ALLE	87.44	121.56	1.58	8.50	10,629.33	0.03%	0.04%	0.22%
Netflix Inc	NFLX	430.97	550.64	n/a	13.00	237,306.57	0.57%		7.39%
Warner Bros Discovery Inc	WBD	2450.13	7.36	n/a		0.00	0.00%		
Agilent Technologies Inc	A	293.06	137.04	0.69	8.00	40,160.26	0.10%	0.07%	0.77%
Trimble Inc	TRMB	244.21	60.07	n/a	5.50	14,669.57	0.04%		0.19%
Elevance Health Inc	ELV	232.42	528.58	1.23	12.50	122,851.51	0.29%	0.36%	3.68%
CME Group Inc	CME	360.03	209.64	2.19	7.00	75,475.64	0.18%	0.40%	1.27%
Juniper Networks Inc	JNPR	324.99	34.82	2.53	8.50	11,316.08	0.03%	0.07%	0.23%
BlackRock Inc	BLK	148.76	754.64	2.70	8.00	112,260.25	0.27%	0.73%	2.15%
DTE Energy Co	DTE	206.93	110.32	3.70	4.50	22,827.97	0.05%	0.20%	0.25%
Celanese Corp	CE	108.91	153.61	1.82	4.50	16,729.05	0.04%	0.07%	0.18%
Nasdaq Inc	NDAQ	575.21	59.85	1.60	6.00	34,426.14	0.08%	0.13%	0.49%
Philip Morris International Inc	PM	1554.56	94.94	5.48	5.00	147,589.64	0.35%	1.94%	1.77%
Ingersoll Rand Inc	IR	403.44	93.32	0.09	10.00	37,648.65	0.09%	0.01%	0.90%
Salesforce Inc	CRM	970.00	268.94	0.59	18.00	260,871.80	0.63%	0.37%	11.25%
Roper Technologies Inc	ROP	107.02	511.46	0.59	6.50	54,737.47	0.13%	0.08%	0.85%
Huntington Ingalls Industries Inc	HII	39.61	276.93	1.88	10.00	10,968.92	0.03%	0.05%	0.26%
MetLife Inc	MET	723.02	71.08	3.07	7.00	51,392.26	0.12%	0.38%	0.86%
Tapestry Inc	TPR	229.37	39.92	3.51	16.50	9,156.29	0.02%	0.08%	0.36%

Name	Ticker	Shares Outst'g	Price	Dividend Yield	Value Line Long-Term Growth Estimate	Market Cap Excl. n/a Growth	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
CSX Corp	CSX	1954.93	33.22	1.44	7.50	64,942.67	0.16%	0.22%	1.17%
Edwards Lifesciences Corp	EW	601.30	84.67	n/a	10.50	50,912.07	0.12%		1.28%
Ameriprise Financial Inc	AMP	100.19	411.79	1.44	10.00	41,257.65	0.10%	0.14%	0.99%
Zebra Technologies Corp	ZBRA	51.42	314.56	n/a	-2.50	16,174.36	0.04%		-0.10%
Zimmer Biomet Holdings Inc	ZBH	205.08	120.28	0.80	6.50	24,667.50	0.06%	0.05%	0.38%
Camden Property Trust	CPT	106.97	99.68	4.13	-6.50	10,662.67	0.03%	0.11%	-0.17%
CBRE Group Inc	CBRE	305.70	86.89	n/a	5.00	26,561.93	0.06%		0.32%
Mastercard Inc	MA	925.72	451.20	0.59	14.50	417,686.22	1.00%	0.59%	14.51%
CarMax Inc	KMX	157.39	67.97	n/a	3.50	10,697.66	0.03%		0.09%
Intercontinental Exchange Inc	ICE	572.62	128.76	1.40	7.00	73,730.04	0.18%	0.25%	1.24%
Fidelity National Information Services Inc	FIS	576.47	67.92	2.12	2.50	39,153.57	0.09%	0.20%	0.23%
Chipotle Mexican Grill Inc	CMG	27.47	3159.60	n/a	22.50	86,784.73	0.21%		4.68%
Wynn Resorts Ltd	WYNN	112.07	91.65	1.09	27.00	10,270.94	0.02%	0.03%	0.66%
Live Nation Entertainment Inc	LYV	230.80	88.91	n/a		0.00	0.00%		
Assurant Inc	AIZ	51.98	174.40	1.65	9.50	9,064.96	0.02%	0.04%	0.21%
NRG Energy Inc	NRG	208.02	72.67	2.24	-2.00	15,116.89	0.04%	0.08%	-0.07%
Monster Beverage Corp	MNST	1040.64	53.45	n/a	12.00	55,621.99	0.13%		1.60%
Regions Financial Corp	RF	918.86	19.27	4.98	4.50	17,706.51	0.04%	0.21%	0.19%
Baker Hughes Co	BKR	998.00	32.62	2.58	28.00	32,554.69	0.08%	0.20%	2.18%
Mosaic Co/The	MOS	321.69	31.39	2.68	-6.00	10,097.82	0.02%	0.06%	-0.15%
Expedia Group Inc	EXPE	130.77	134.63	n/a	39.00	17,604.89	0.04%		1.65%
CF Industries Holdings Inc	CF	188.34	78.97	2.53	2.00	14,873.05	0.04%	0.09%	0.07%
APA Corp	APA	370.89	31.44	3.18	6.50	11,660.72	0.03%	0.09%	0.18%
Leidos Holdings Inc	LDOS	135.21	140.22	1.08	7.50	18,959.43	0.05%	0.05%	0.34%
Alphabet Inc	GOOG	5617.00	164.64	0.49	12.00	924,782.88	2.22%	1.08%	26.59%
First Solar Inc	FSLR	107.03	176.30	n/a	34.00	18,868.68	0.05%		1.54%
TE Connectivity Ltd	TEL	306.23	141.48	1.84	10.50	43,325.14	0.10%	0.19%	1.09%
Discover Financial Services	DFS	251.00	126.73	2.21	4.00	31,809.23	0.08%	0.17%	0.30%
Visa Inc	V	1574.15	268.61	0.77	13.50	422,832.97	1.01%	0.78%	13.68%
Mid-America Apartment Communities Inc	MAA	116.69	130.00	4.52	-11.00	15,169.44	0.04%	0.16%	-0.40%
Xylem Inc/NY	XYL	241.77	130.70	1.10	6.00	31,599.34	0.08%	0.08%	0.45%
Marathon Petroleum Corp	MPC	352.33	181.72	1.82	15.50	64,025.41	0.15%	0.28%	2.38%
Tractor Supply Co	TSCO	107.93	273.08	1.61	11.50	29,474.07	0.07%	0.11%	0.81%
Advanced Micro Devices Inc	AMD	1615.79	158.38	n/a	17.50	255,908.35	0.61%		10.73%
ResMed Inc	RMD	146.91	213.99	0.90	11.50	31,436.63	0.08%	0.07%	0.87%
Mettler-Toledo International Inc	MTD	21.39	1229.70	n/a	9.00	26,300.82	0.06%		0.57%
VICI Properties Inc	VICI	1043.14	28.55	5.81	9.50	29,781.56	0.07%	0.41%	0.68%
Copart Inc	CPRT	961.46	54.31	n/a	9.00	52,217.00	0.13%		1.13%
Jacobs Solutions Inc	J	125.65	143.53	0.81	10.00	18,034.69	0.04%	0.03%	0.43%
Albemarle Corp	ALB	117.53	120.31	1.33	-3.50	14,139.43	0.03%	0.05%	-0.12%
Fortinet Inc	FTNT	763.03	63.18	n/a	24.00	48,208.30	0.12%		2.77%
Moderna Inc	MRNA	382.88	110.31	n/a	-20.00	42,235.49	0.10%		-2.02%
Essex Property Trust Inc	ESS	64.21	246.25	3.98	1.00	15,810.73	0.04%	0.15%	0.04%
CoStar Group Inc	CSGP	408.34	91.53	n/a	14.00	37,375.54	0.09%		1.25%
Realty Income Corp	O	861.15	53.54	5.76	5.50	46,105.97	0.11%	0.64%	0.61%
Westrock Co	WRK	258.15	47.96	2.52	8.50	12,380.78	0.03%	0.07%	0.25%
Westinghouse Air Brake Technologies Corp	WAB	176.39	161.08	0.50	12.00	28,412.10	0.07%	0.03%	0.82%
Pool Corp	POOL	38.33	362.53	1.21	14.00	13,895.41	0.03%	0.04%	0.47%
Western Digital Corp	WDC	326.53	70.83	n/a	18.00	23,127.77	0.06%		1.00%
PepsiCo Inc	PEP	1374.79	175.91	3.08	6.50	241,838.61	0.58%	1.79%	3.77%
Diamondback Energy Inc	FANG	178.34	201.13	6.13	2.50	35,869.52	0.09%	0.53%	0.21%
Palo Alto Networks Inc	PANW	323.10	290.89	n/a		0.00	0.00%		
ServiceNow Inc	NOW	205.38	693.33	n/a	32.50	142,397.50	0.34%		11.09%
Church & Dwight Co Inc	CHD	243.91	107.89	1.05	5.50	26,314.91	0.06%	0.07%	0.35%
Federal Realty Investment Trust	FRT	82.78	104.17	4.19	2.50	8,622.67	0.02%	0.09%	0.05%
MGM Resorts International	MGM	317.02	39.44	n/a	25.00	12,503.11	0.03%		0.75%
American Electric Power Co Inc	AEP	526.59	86.03	4.09	6.50	45,302.54	0.11%	0.44%	0.71%
Invitation Homes Inc	INVH	611.96	34.20	3.27	8.50	20,928.96	0.05%	0.16%	0.43%
PTC Inc	PTC	119.55	177.44	n/a	11.00	21,213.31	0.05%		0.56%
JB Hunt Transport Services Inc	JBHT	103.20	162.57	1.06	8.50	16,776.74	0.04%	0.04%	0.34%
Lam Research Corp	LRCX	130.74	894.41	0.89	9.00	116,931.59	0.28%	0.25%	2.52%
Mohawk Industries Inc	MHK	63.86	115.32	n/a	1.00	7,364.68	0.02%		0.02%
GE HealthCare Technologies Inc	GEHC	456.47	76.24	0.16		0.00	0.00%	0.00%	
Pentair PLC	PNR	166.03	79.09	1.16	11.00	13,130.92	0.03%	0.04%	0.35%
Vertex Pharmaceuticals Inc	VRTX	258.46	392.81	n/a	9.50	101,525.28	0.24%		2.31%
Amcor PLC	AMCR	1445.34	8.94	5.59	11.50	12,921.37	0.03%	0.17%	0.36%
Meta Platforms Inc	META	2191.45	430.17	0.46	17.50	942,694.33	2.26%	1.05%	39.53%
T-Mobile US Inc	TMUS	1171.85	164.17	1.58	19.50	192,383.27	0.46%	0.73%	8.99%
United Rentals Inc	URI	66.59	667.99	0.98	17.00	44,481.45	0.11%	0.10%	1.81%
Alexandria Real Estate Equities Inc	ARE	174.88	115.87	4.38	8.50	20,263.69	0.05%	0.21%	0.41%
Honeywell International Inc	HON	651.19	192.73	2.24	10.00	125,503.08	0.30%	0.67%	3.01%
Delta Air Lines Inc	DAL	645.31	50.07	0.80		0.00	0.00%	0.00%	
United Airlines Holdings Inc	UAL	328.80	51.46	n/a		0.00	0.00%		
Seagate Technology Holdings PLC	STX	209.99	85.91	3.26	18.50	18,040.15	0.04%	0.14%	0.80%
News Corp	NWS	191.10	24.54	0.81		0.00	0.00%	0.00%	
Centene Corp	CNC	534.91	73.06	n/a	12.50	39,080.23	0.09%		1.17%
Martin Marietta Materials Inc	MLM	61.64	587.07	0.50	12.50	36,186.99	0.09%	0.04%	1.08%
Teradyne Inc	TER	152.97	116.32	0.41	5.50	17,793.94	0.04%	0.02%	0.23%
PayPal Holdings Inc	PYPL	1046.05	67.92	n/a	12.00	71,047.44	0.17%		2.04%
Tesla Inc	TSLA	3189.20	183.28	n/a	13.50	584,515.84	1.40%		18.91%
Arch Capital Group Ltd	ACGL	374.15	93.54	n/a	24.00	34,998.08	0.08%		2.01%
Dow Inc	DOW	703.27	56.90	4.92	1.50	40,015.95	0.10%	0.47%	0.14%
Everest Group Ltd	EG	43.38	366.41	1.91	10.50	15,895.60	0.04%	0.07%	0.40%
Teledyne Technologies Inc	TDY	47.42	381.48	n/a	8.00	18,090.54	0.04%		0.35%

Name	Ticker	Shares Outst'g	Price	Dividend Yield	Value Line Long-Term Growth Estimate	Market Cap Excl. n/a Growth	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
GE Vernova Inc	GEV	274.09	153.71	n/a		0.00	0.00%		
News Corp	NWSA	380.02	23.80	0.84	13.50	9,044.57	0.02%	0.02%	0.29%
Exelon Corp	EXC	999.74	37.58	4.04		0.00	0.00%	0.00%	
Global Payments Inc	GPN	257.99	122.77	0.81	12.00	31,672.82	0.08%	0.06%	0.91%
Crown Castle Inc	CCI	435.00	93.78	6.68	7.00	40,794.30	0.10%	0.65%	0.68%
Aptiv PLC	APTV	272.68	71.00	n/a	33.50	19,360.21	0.05%		1.55%
Align Technology Inc	ALGN	75.28	282.38	n/a	17.00	21,257.28	0.05%		0.87%
Illumina Inc	ILMN	158.90	123.05	n/a	-6.00	19,552.65	0.05%		-0.28%
Kenvue Inc	KVUE	1914.65	18.82	4.25		0.00	0.00%	0.00%	
Targa Resources Corp	TRGP	223.16	114.06	2.63		0.00	0.00%	0.00%	
Bunge Global SA	BG	141.60	101.76	2.60	0.00	14,408.71	0.03%	0.09%	0.00%
LKQ Corp	LKQ	266.78	43.13	2.78	7.00	11,506.05	0.03%	0.08%	0.19%
Deckers Outdoor Corp	DECK	25.67	818.47	n/a	14.00	21,008.49	0.05%		0.70%
Zoetis Inc	ZTS	456.95	159.24	1.09	7.50	72,764.24	0.17%	0.19%	1.31%
Equinix Inc	EQIX	94.91	711.11	2.40	16.00	67,487.89	0.16%	0.39%	2.59%
Digital Realty Trust Inc	DLR	311.61	138.78	3.52	-5.00	43,244.96	0.10%	0.36%	-0.52%
Molina Healthcare Inc	MOH	59.00	342.10	n/a	12.50	20,183.90	0.05%		0.60%
Las Vegas Sands Corp	LVS	745.05	44.36	1.80		0.00	0.00%	0.00%	

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE, BLENDED MRP, & VL BETA
K = Rf + β (Rm − Rf)

Company	Ticker	[1] 30-day Average of 30-Year U.S. Treasury Bond Yield	[2] Beta (β)	[3] Forward Market Return (Rm)	[4] Average Forward and Historical Market Risk Premium (Rm − Rf)	[5] ROE (K)
Atmos Energy Corporation	ATO	4.59%	0.85	15.17%	8.88%	12.14%
New Jersey Resources Corporation	NJR	4.59%	0.95	15.17%	8.88%	13.02%
NiSource Inc.	NI	4.59%	0.90	15.17%	8.88%	12.58%
ONE Gas, Inc.	OGS	4.59%	0.85	15.17%	8.88%	12.14%
Southwest Gas Holding	SWX	4.59%	0.90	15.17%	8.88%	12.58%
Spire, Inc.	SR	4.59%	0.85	15.17%	8.88%	12.14%
Ameren Corporation	AEE	4.59%	0.90	15.17%	8.88%	12.58%
Avista Corporation	AVA	4.59%	0.95	15.17%	8.88%	13.02%
Black Hills Corporation	BKH	4.59%	1.05	15.17%	8.88%	13.91%
CenterPoint Energy, Inc.	CNP	4.59%	1.15	15.17%	8.88%	14.80%
CMS Energy Corporation	CMS	4.59%	0.85	15.17%	8.88%	12.14%
DTE Energy Company	DTE	4.59%	1.00	15.17%	8.88%	13.47%
NorthWestern Energy Group, Inc.	NWE	4.59%	0.95	15.17%	8.88%	13.02%
Public Service Enterprise Group Inc.	PEG	4.59%	0.95	15.17%	8.88%	13.02%
Southern Company	SO	4.59%	0.95	15.17%	8.88%	13.02%
Wisconsin Energy Corporation	WEC	4.59%	0.85	15.17%	8.88%	12.14%
Gas Proxy Group Mean			0.88			12.43%
Combined Proxy Group Mean			0.93			12.86%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Value Line, as of April 30, 2024
[3] Source: Average of Market Returns presented in Exh. 407 page 1-15
[4] Equals Average of ([3] - [1], 7.17%)
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE, BLENDED MRP, & BLOOMBERG BETA
K = Rf + β (Rm − Rf)

Company	Ticker	[1] 30-day Average of 30-Year U.S. Treasury Bond Yield	[2] Beta (β)	[3] Forward Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)
Atmos Energy Corporation	ATO	4.59%	0.828	15.17%	8.88%	11.94%
New Jersey Resources Corporation	NJR	4.59%	0.852	15.17%	8.88%	12.16%
NiSource Inc.	NI	4.59%	0.880	15.17%	8.88%	12.40%
ONE Gas, Inc.	OGS	4.59%	0.834	15.17%	8.88%	11.99%
Southwest Gas Holding	SWX	4.59%	0.912	15.17%	8.88%	12.69%
Spire, Inc.	SR	4.59%	0.862	15.17%	8.88%	12.24%
Ameren Corporation	AEE	4.59%	0.840	15.17%	8.88%	12.04%
Avista Corporation	AVA	4.59%	0.837	15.17%	8.88%	12.02%
Black Hills Corporation	BKH	4.59%	1.023	15.17%	8.88%	13.67%
CenterPoint Energy, Inc.	CNP	4.59%	1.106	15.17%	8.88%	14.41%
CMS Energy Corporation	CMS	4.59%	0.838	15.17%	8.88%	12.03%
DTE Energy Company	DTE	4.59%	0.932	15.17%	8.88%	12.87%
NorthWestern Energy Group, Inc.	NWE	4.59%	0.995	15.17%	8.88%	13.42%
Public Service Enterprise Group Inc.	PEG	4.59%	0.949	15.17%	8.88%	13.01%
Southern Company	SO	4.59%	0.893	15.17%	8.88%	12.51%
Wisconsin Energy Corporation	WEC	4.59%	0.82	15.17%	8.88%	11.86%
Gas Proxy Group Mean			0.86			12.24%
Combined Proxy Group Mean			0.90			12.58%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 5-Year Betas as of January 31, 2024
[3] Source: Average of Market Returns presented in Exh. 407 page 1-15
[4] Equals Average of ([3] - [1], 7.17%)
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE, BLENDED MRP, & VL BETA
K = Rf + β (Rm − Rf)

Company	Ticker	[1] Projected 30-year U.S. Treasury bond yield (2025 - 2029)	[2] Beta (β)	[3] Forward Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)
Atmos Energy Corporation	ATO	4.10%	0.85	15.17%	9.12%	11.85%
New Jersey Resources Corporation	NJR	4.10%	0.95	15.17%	9.12%	12.77%
NiSource Inc.	NI	4.10%	0.90	15.17%	9.12%	12.31%
ONE Gas, Inc.	OGS	4.10%	0.85	15.17%	9.12%	11.85%
Southwest Gas Holding	SWX	4.10%	0.90	15.17%	9.12%	12.31%
Spire, Inc.	SR	4.10%	0.85	15.17%	9.12%	11.85%
Ameren Corporation	AEE	4.10%	0.90	15.17%	9.12%	12.31%
Avista Corporation	AVA	4.10%	0.95	15.17%	9.12%	12.77%
Black Hills Corporation	BKH	4.10%	1.05	15.17%	9.12%	13.68%
CenterPoint Energy, Inc.	CNP	4.10%	1.15	15.17%	9.12%	14.59%
CMS Energy Corporation	CMS	4.10%	0.85	15.17%	9.12%	11.85%
DTE Energy Company	DTE	4.10%	1.00	15.17%	9.12%	13.22%
NorthWestern Energy Group, Inc.	NWE	4.10%	0.95	15.17%	9.12%	12.77%
Public Service Enterprise Group Inc.	PEG	4.10%	0.95	15.17%	9.12%	12.77%
Southern Company	SO	4.10%	0.95	15.17%	9.12%	12.77%
Wisconsin Energy Corporation	WEC	4.10%	0.85	15.17%	9.12%	11.85%
Gas Proxy Group Mean			0.88			12.16%
Combined Proxy Group Mean			0.93			12.59%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 42, No. 12, December 1, 2023 at 14
[2] Source: Value Line, as of April 30, 2024
[3] Source: Average of Market Returns presented in Exh. 407 page 1-15
[4] Equals Average of ([3] - [1], 7.17%)
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE, BLENDED MRP, & BLOOMBERG BETA
K = Rf + β (Rm − Rf)

Company	Ticker	[1] Projected 30-year U.S. Treasury bond yield (2025 - 2029)	[2] Beta (β)	[3] Forward Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)
Atmos Energy Corporation	ATO	4.10%	0.828	15.17%	9.12%	11.65%
New Jersey Resources Corporation	NJR	4.10%	0.852	15.17%	9.12%	11.87%
NiSource Inc.	NI	4.10%	0.880	15.17%	9.12%	12.13%
ONE Gas, Inc.	OGS	4.10%	0.834	15.17%	9.12%	11.70%
Southwest Gas Holding	SWX	4.10%	0.912	15.17%	9.12%	12.42%
Spire, Inc.	SR	4.10%	0.862	15.17%	9.12%	11.96%
Ameren Corporation	AEE	4.10%	0.840	15.17%	9.12%	11.76%
Avista Corporation	AVA	4.10%	0.837	15.17%	9.12%	11.74%
Black Hills Corporation	BKH	4.10%	1.023	15.17%	9.12%	13.43%
CenterPoint Energy, Inc.	CNP	4.10%	1.106	15.17%	9.12%	14.19%
CMS Energy Corporation	CMS	4.10%	0.838	15.17%	9.12%	11.74%
DTE Energy Company	DTE	4.10%	0.932	15.17%	9.12%	12.60%
NorthWestern Energy Group, Inc.	NWE	4.10%	0.995	15.17%	9.12%	13.18%
Public Service Enterprise Group Inc.	PEG	4.10%	0.949	15.17%	9.12%	12.75%
Southern Company	SO	4.10%	0.893	15.17%	9.12%	12.24%
Wisconsin Energy Corporation	WEC	4.10%	0.819	15.17%	9.12%	11.57%
Gas Proxy Group Mean			0.86			11.96%
Combined Proxy Group Mean			0.90			12.31%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 42, No. 12, December 1, 2023 at 14
[2] Source: Bloomberg Professional, 5-Year Betas as of January 31, 2024
[3] Source: Average of Market Returns presented in Exh. 407 page 1-15
[4] Equals Average of ([3] - [1], 7.17%)
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE, HISTORICAL MRP, & VL BETA
K = Rf + β (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)
Atmos Energy Corporation	ATO	4.59%	0.85	11.76%	7.17%	10.69%
New Jersey Resources Corporation	NJR	4.59%	0.95	11.76%	7.17%	11.40%
NiSource Inc.	NI	4.59%	0.90	11.76%	7.17%	11.05%
ONE Gas, Inc.	OGS	4.59%	0.85	11.76%	7.17%	10.69%
Southwest Gas Holding	SWX	4.59%	0.90	11.76%	7.17%	11.05%
Spire, Inc.	SR	4.59%	0.85	11.76%	7.17%	10.69%
Ameren Corporation	AEE	4.59%	0.90	11.76%	7.17%	11.05%
Avista Corporation	AVA	4.59%	0.95	11.76%	7.17%	11.40%
Black Hills Corporation	BKH	4.59%	1.05	11.76%	7.17%	12.12%
CenterPoint Energy, Inc.	CNP	4.59%	1.15	11.76%	7.17%	12.84%
CMS Energy Corporation	CMS	4.59%	0.85	11.76%	7.17%	10.69%
DTE Energy Company	DTE	4.59%	1.00	11.76%	7.17%	11.76%
NorthWestern Energy Group, Inc.	NWE	4.59%	0.95	11.76%	7.17%	11.40%
Public Service Enterprise Group Inc.	PEG	4.59%	0.95	11.76%	7.17%	11.40%
Southern Company	SO	4.59%	0.95	11.76%	7.17%	11.40%
Wisconsin Energy Corporation	WEC	4.59%	0.85	11.76%	7.17%	10.69%
Gas Proxy Group Mean			0.88			10.93%
Combined Proxy Group Mean			0.93			11.27%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Value Line, as of April 30, 2024
[3] Equals [1] + [4]
[4] Source: Kroll, arithmetic average MRP 1926-2023
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE, HISTORICAL MRP, & BLOOMBERG BETA
K = Rf + β (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)
Atmos Energy Corporation	ATO	4.59%	0.828	11.76%	7.17%	10.53%
New Jersey Resources Corporation	NJR	4.59%	0.852	11.76%	7.17%	10.70%
NiSource Inc.	NI	4.59%	0.880	11.76%	7.17%	10.90%
ONE Gas, Inc.	OGS	4.59%	0.834	11.76%	7.17%	10.57%
Southwest Gas Holding	SWX	4.59%	0.912	11.76%	7.17%	11.13%
Spire, Inc.	SR	4.59%	0.862	11.76%	7.17%	10.77%
Ameren Corporation	AEE	4.59%	0.840	11.76%	7.17%	10.61%
Avista Corporation	AVA	4.59%	0.837	11.76%	7.17%	10.59%
Black Hills Corporation	BKH	4.59%	1.023	11.76%	7.17%	11.93%
CenterPoint Energy, Inc.	CNP	4.59%	1.106	11.76%	7.17%	12.52%
CMS Energy Corporation	CMS	4.59%	0.838	11.76%	7.17%	10.60%
DTE Energy Company	DTE	4.59%	0.932	11.76%	7.17%	11.28%
NorthWestern Energy Group, Inc.	NWE	4.59%	0.995	11.76%	7.17%	11.73%
Public Service Enterprise Group Inc.	PEG	4.59%	0.949	11.76%	7.17%	11.40%
Southern Company	SO	4.59%	0.893	11.76%	7.17%	10.99%
Wisconsin Energy Corporation	WEC	4.59%	0.819	11.76%	7.17%	10.47%
Gas Proxy Group Mean			0.86			10.77%
Combined Proxy Group Mean			0.90			11.05%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 5-Year Betas as of January 31, 2024
[3] Equals [1] + [4]
[4] Source: Kroll, arithmetic average MRP 1926-2023
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE, HISTORICAL MRP, & VL BETA
K = Rf + β (Rm − Rf)

Company	Ticker	[1] Projected 30-year U.S. Treasury bond yield (2025 - 2029)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)
Atmos Energy Corporation	ATO	4.10%	0.85	11.76%	7.17%	10.20%
New Jersey Resources Corporation	NJR	4.10%	0.95	11.76%	7.17%	10.91%
NiSource Inc.	NI	4.10%	0.90	11.76%	7.17%	10.55%
ONE Gas, Inc.	OGS	4.10%	0.85	11.76%	7.17%	10.20%
Southwest Gas Holding	SWX	4.10%	0.90	11.76%	7.17%	10.55%
Spire, Inc.	SR	4.10%	0.85	11.76%	7.17%	10.20%
Ameren Corporation	AEE	4.10%	0.90	11.76%	7.17%	10.55%
Avista Corporation	AVA	4.10%	0.95	11.76%	7.17%	10.91%
Black Hills Corporation	BKH	4.10%	1.05	11.76%	7.17%	11.63%
CenterPoint Energy, Inc.	CNP	4.10%	1.15	11.76%	7.17%	12.35%
CMS Energy Corporation	CMS	4.10%	0.85	11.76%	7.17%	10.20%
DTE Energy Company	DTE	4.10%	1.00	11.76%	7.17%	11.27%
NorthWestern Energy Group, Inc.	NWE	4.10%	0.95	11.76%	7.17%	10.91%
Public Service Enterprise Group Inc.	PEG	4.10%	0.95	11.76%	7.17%	10.91%
Southern Company	SO	4.10%	0.95	11.76%	7.17%	10.91%
Wisconsin Energy Corporation	WEC	4.10%	0.85	11.76%	7.17%	10.20%
Gas Proxy Group Mean			0.88			10.44%
Combined Proxy Group Mean			0.93			10.78%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 42, No. 12, December 1, 2023 at 14
[2] Source: Value Line, as of April 30, 2024
[3] Equals [1] + [4]
[4] Source: Kroll, arithmetic average MRP 1926-2023
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE, HISTORICAL MRP, & BLOOMBERG BETA
K = Rf + β (Rm − Rf)

Company	Ticker	[1] Projected 30-year U.S. Treasury bond yield (2025 - 2029)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)
Atmos Energy Corporation	ATO	4.10%	0.828	11.76%	7.17%	10.04%
New Jersey Resources Corporation	NJR	4.10%	0.852	11.76%	7.17%	10.21%
NiSource Inc.	NI	4.10%	0.880	11.76%	7.17%	10.41%
ONE Gas, Inc.	OGS	4.10%	0.834	11.76%	7.17%	10.08%
Southwest Gas Holding	SWX	4.10%	0.912	11.76%	7.17%	10.64%
Spire, Inc.	SR	4.10%	0.862	11.76%	7.17%	10.28%
Ameren Corporation	AEE	4.10%	0.840	11.76%	7.17%	10.12%
Avista Corporation	AVA	4.10%	0.837	11.76%	7.17%	10.10%
Black Hills Corporation	BKH	4.10%	1.023	11.76%	7.17%	11.43%
CenterPoint Energy, Inc.	CNP	4.10%	1.106	11.76%	7.17%	12.03%
CMS Energy Corporation	CMS	4.10%	0.838	11.76%	7.17%	10.11%
DTE Energy Company	DTE	4.10%	0.932	11.76%	7.17%	10.79%
NorthWestern Energy Group, Inc.	NWE	4.10%	0.995	11.76%	7.17%	11.24%
Public Service Enterprise Group Inc.	PEG	4.10%	0.949	11.76%	7.17%	10.90%
Southern Company	SO	4.10%	0.893	11.76%	7.17%	10.50%
Wisconsin Energy Corporation	WEC	4.10%	0.819	11.76%	7.17%	9.98%
Gas Proxy Group Mean			0.86			10.28%
Combined Proxy Group Mean			0.90			10.55%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 42, No. 12, December 1, 2023 at 14
[2] Source: Bloomberg Professional, 5-Year Betas as of January 31, 2024
[3] Equals [1] + [4]
[4] Source: Kroll, arithmetic average MRP 1926-2023
[5] Equals [1] + [2] x [4]

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of
James M. Coyne and Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 2506

June 4, 2024

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Risk Premium -- Natural Gas Utilities

	[1] Average Authorized Gas ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
1992.1	12.42%	7.80%	4.62%
1992.2	11.98%	7.89%	4.09%
1992.3	11.87%	7.45%	4.42%
1992.4	11.94%	7.52%	4.42%
1993.1	11.75%	7.07%	4.68%
1993.2	11.71%	6.86%	4.85%
1993.3	11.39%	6.31%	5.07%
1993.4	11.16%	6.14%	5.02%
1994.1	11.12%	6.57%	4.55%
1994.2	10.84%	7.35%	3.48%
1994.3	10.87%	7.58%	3.28%
1994.4	11.53%	7.96%	3.57%
1995.2	11.00%	6.94%	4.06%
1995.3	11.07%	6.71%	4.35%
1995.4	11.61%	6.23%	5.37%
1996.1	11.45%	6.29%	5.16%
1996.2	10.88%	6.92%	3.96%
1996.3	11.25%	6.96%	4.29%
1996.4	11.19%	6.62%	4.58%
1997.1	11.31%	6.81%	4.49%
1997.2	11.70%	6.93%	4.77%
1997.3	12.00%	6.53%	5.47%
1997.4	10.92%	6.14%	4.78%
1998.2	11.37%	5.85%	5.52%
1998.3	11.41%	5.47%	5.94%
1998.4	11.69%	5.10%	6.59%
1999.1	10.82%	5.37%	5.44%
1999.2	11.25%	5.79%	5.46%
1999.4	10.38%	6.25%	4.12%
2000.1	10.66%	6.29%	4.36%
2000.2	11.03%	5.97%	5.06%
2000.3	11.33%	5.79%	5.55%
2000.4	12.10%	5.69%	6.41%
2001.1	11.38%	5.44%	5.93%
2001.2	10.75%	5.70%	5.05%
2001.4	10.65%	5.30%	5.35%
2002.1	10.67%	5.51%	5.15%
2002.2	11.64%	5.61%	6.03%
2002.3	11.50%	5.08%	6.42%
2002.4	11.01%	4.93%	6.08%
2003.1	11.38%	4.85%	6.53%
2003.2	11.36%	4.60%	6.76%
2003.3	10.61%	5.11%	5.50%
2003.4	10.84%	5.11%	5.73%
2004.1	11.06%	4.88%	6.18%
2004.2	10.57%	5.32%	5.25%
2004.3	10.37%	5.06%	5.31%
2004.4	10.66%	4.86%	5.79%
2005.1	10.65%	4.69%	5.96%
2005.2	10.54%	4.47%	6.07%
2005.3	10.47%	4.44%	6.03%
2005.4	10.32%	4.68%	5.63%
2006.1	10.68%	4.63%	6.05%
2006.2	10.60%	5.14%	5.46%
2006.3	10.34%	4.99%	5.34%
2006.4	10.14%	4.74%	5.40%
2007.1	10.52%	4.80%	5.72%
2007.2	10.13%	4.99%	5.14%
2007.3	10.03%	4.95%	5.08%
2007.4	10.12%	4.61%	5.50%
2008.1	10.38%	4.41%	5.97%
2008.2	10.17%	4.57%	5.60%

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Risk Premium -- Natural Gas Utilities

	[1] Average Authorized Gas ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
2008.3	10.55%	4.44%	6.11%
2008.4	10.34%	3.65%	6.69%
2009.1	10.24%	3.44%	6.81%
2009.2	10.11%	4.17%	5.94%
2009.3	9.88%	4.32%	5.56%
2009.4	10.31%	4.34%	5.97%
2010.1	10.24%	4.62%	5.61%
2010.2	9.99%	4.36%	5.62%
2010.3	10.43%	3.86%	6.57%
2010.4	10.09%	4.17%	5.93%
2011.1	10.10%	4.56%	5.54%
2011.2	9.85%	4.34%	5.51%
2011.3	9.65%	3.69%	5.96%
2011.4	9.88%	3.04%	6.84%
2012.1	9.63%	3.14%	6.50%
2012.2	9.83%	2.93%	6.90%
2012.3	9.75%	2.74%	7.01%
2012.4	10.06%	2.86%	7.19%
2013.1	9.57%	3.13%	6.44%
2013.2	9.47%	3.14%	6.33%
2013.3	9.60%	3.71%	5.89%
2013.4	9.83%	3.79%	6.04%
2014.1	9.54%	3.69%	5.85%
2014.2	9.84%	3.44%	6.39%
2014.3	9.45%	3.26%	6.19%
2014.4	10.28%	2.96%	7.32%
2015.1	9.47%	2.55%	6.91%
2015.2	9.43%	2.88%	6.55%
2015.3	9.75%	2.96%	6.79%
2015.4	9.68%	2.96%	6.72%
2016.1	9.48%	2.72%	6.76%
2016.2	9.42%	2.57%	6.85%
2016.3	9.47%	2.28%	7.19%
2016.4	9.67%	2.83%	6.84%
2017.1	9.60%	3.04%	6.56%
2017.2	9.47%	2.90%	6.58%
2017.3	10.14%	2.82%	7.32%
2017.4	9.70%	2.82%	6.88%
2018.1	9.68%	3.02%	6.66%
2018.2	9.43%	3.09%	6.34%
2018.3	9.71%	3.06%	6.65%
2018.4	9.53%	3.27%	6.26%
2019.1	9.55%	3.01%	6.54%
2019.2	9.73%	2.78%	6.94%
2019.3	9.95%	2.29%	7.66%
2019.4	9.74%	2.25%	7.48%
2020.1	9.35%	1.89%	7.46%
2020.2	9.55%	1.38%	8.17%
2020.3	9.52%	1.37%	8.15%
2020.4	9.50%	1.62%	7.88%
2021.1	9.71%	2.07%	7.64%
2021.2	9.48%	2.25%	7.22%
2021.3	9.43%	1.93%	7.50%
2021.4	9.59%	1.94%	7.65%
2022.1	9.38%	2.25%	7.12%
2022.2	9.23%	3.03%	6.19%
2022.3	9.52%	3.26%	6.26%
2022.4	9.65%	3.88%	5.77%
2023.1	9.64%	3.74%	5.89%
2023.2	9.40%	3.80%	5.60%
2023.3	9.53%	4.23%	5.30%
2023.4	9.62%	4.58%	5.04%
2024.1	9.62%	4.32%	5.29%
2024.2	10.16%	4.65%	5.50%
AVERAGE	10.38%	4.48%	5.89%
MEDIAN	10.24%	4.51%	5.93%

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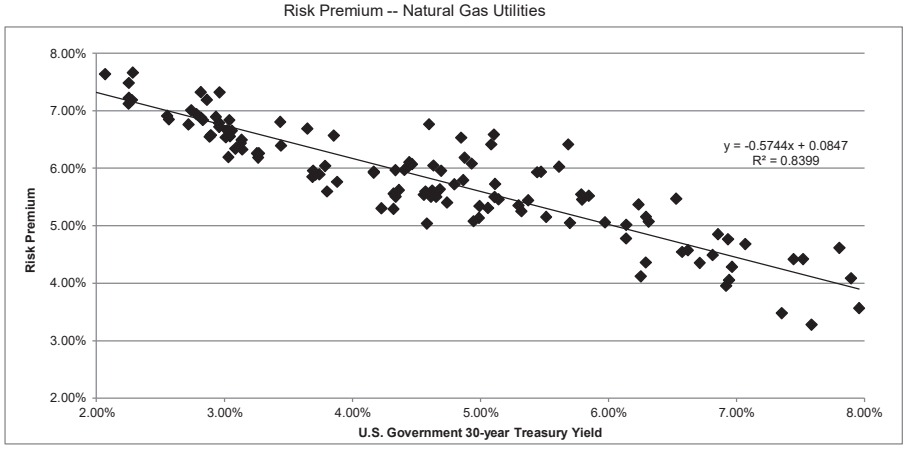

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.91645
R Square	0.83987
Adjusted R Square	0.83858
Standard Error	0.00406
Observations	126

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.0107	0.0107	650.3830	0.0000
Residual	124	0.0020	0.0000		
Total	125	0.0127			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	0.0847	0.00107	78.97794	0.00000	0.08257	0.08681
U.S. Govt. 30-year Treasury	-0.5744	0.02252	-25.50261	0.00000	-0.61903	-0.52986

	[7] U.S. Govt. 30-year Treasury	[8] Risk Premium	[9] ROE
Current 30-day average of 30-year U.S. Treasury bond yield [4]	4.59%	5.83%	10.42%
Blue Chip Near-Term Projected Forecast (Q3 2024 - Q3 2025) [5]	4.32%	5.99%	10.31%
Blue Chip Long-Term Projected Forecast (2025-2029) [6]	4.10%	6.11%	10.21%
AVERAGE			10.31%

Notes:
[1] Source: Regulatory Research Associates, rate cases through April 30, 2024
[2] Source: Bloomberg Professional, quarterly bond yields are the average of each trading day in the quarter
[3] Equals Column [1] − Column [2]
[4] Source: Bloomberg Professional, 30-day average as of April 30, 2024
[5] Source: Blue Chip Financial Forecasts, Vol. 43, No. 5, May 1, 2024 at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 42, No. 12, December 1, 2023 at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.084688 + (-0.574443 x Column [7])
[9] Equals Column [7] + Column [8]

Risk Premium -- Electric Utilities (US)

	[1] Average Authorized Electric ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
1992.1	12.38%	7.80%	4.58%
1992.2	11.83%	7.89%	3.93%
1992.3	12.03%	7.45%	4.59%
1992.4	12.14%	7.52%	4.62%
1993.1	11.84%	7.07%	4.77%
1993.2	11.64%	6.86%	4.79%
1993.3	11.15%	6.31%	4.84%
1993.4	11.04%	6.14%	4.90%
1994.1	11.07%	6.57%	4.49%
1994.2	11.13%	7.35%	3.78%
1994.3	12.75%	7.58%	5.17%
1994.4	11.24%	7.96%	3.28%
1995.1	11.96%	7.63%	4.34%
1995.2	11.32%	6.94%	4.37%
1995.3	11.37%	6.71%	4.66%
1995.4	11.58%	6.23%	5.35%
1996.1	11.46%	6.29%	5.17%
1996.2	11.46%	6.92%	4.54%
1996.3	10.70%	6.96%	3.74%
1996.4	11.56%	6.62%	4.94%
1997.1	11.08%	6.81%	4.27%
1997.2	11.62%	6.93%	4.68%
1997.3	12.00%	6.53%	5.47%
1997.4	11.06%	6.14%	4.92%
1998.1	11.31%	5.88%	5.43%
1998.2	12.20%	5.85%	6.35%
1998.3	11.65%	5.47%	6.18%
1998.4	12.30%	5.10%	7.20%
1999.1	10.40%	5.37%	5.03%
1999.2	10.94%	5.79%	5.15%
1999.3	10.75%	6.04%	4.71%
1999.4	11.10%	6.25%	4.85%
2000.1	11.21%	6.29%	4.92%
2000.2	11.00%	5.97%	5.03%
2000.3	11.68%	5.79%	5.89%
2000.4	12.50%	5.69%	6.81%
2001.1	11.38%	5.44%	5.93%
2001.2	10.88%	5.70%	5.18%
2001.3	10.76%	5.52%	5.23%
2001.4	11.57%	5.30%	6.27%
2002.1	10.05%	5.51%	4.54%
2002.2	11.41%	5.61%	5.79%
2002.3	11.25%	5.08%	6.17%
2002.4	11.57%	4.93%	6.64%
2003.1	11.43%	4.85%	6.58%
2003.2	11.16%	4.60%	6.56%
2003.3	9.88%	5.11%	4.76%
2003.4	11.09%	5.11%	5.98%
2004.1	11.00%	4.88%	6.12%
2004.2	10.64%	5.32%	5.32%
2004.3	10.75%	5.06%	5.69%
2004.4	10.91%	4.86%	6.04%
2005.1	10.56%	4.69%	5.87%
2005.2	10.13%	4.47%	5.66%
2005.3	10.85%	4.44%	6.41%
2005.4	10.59%	4.68%	5.91%
2006.1	10.38%	4.63%	5.75%
2006.2	10.63%	5.14%	5.49%
2006.3	10.06%	4.99%	5.07%
2006.4	10.39%	4.74%	5.65%
2007.1	10.39%	4.80%	5.59%
2007.2	10.27%	4.99%	5.28%
2007.3	10.02%	4.95%	5.07%
2007.4	10.43%	4.61%	5.81%
2008.1	10.15%	4.41%	5.75%
2008.2	10.54%	4.57%	5.97%
2008.3	10.38%	4.44%	5.94%
2008.4	10.39%	3.65%	6.74%
2009.1	10.45%	3.44%	7.01%
2009.2	10.58%	4.17%	6.42%
2009.3	10.41%	4.32%	6.09%
2009.4	10.54%	4.34%	6.21%
2010.1	10.45%	4.62%	5.82%
2010.2	10.08%	4.36%	5.71%
2010.3	10.29%	3.86%	6.43%
2010.4	10.34%	4.17%	6.17%
2011.1	9.96%	4.56%	5.40%
2011.2	10.12%	4.34%	5.78%
2011.3	10.36%	3.69%	6.67%
2011.4	10.34%	3.04%	7.31%
2012.1	10.30%	3.14%	7.17%
2012.2	9.92%	2.93%	6.98%

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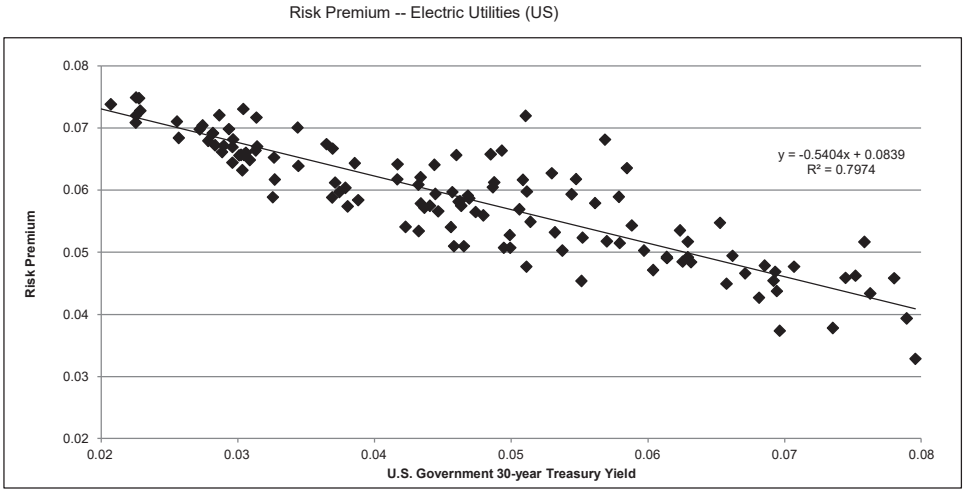
Risk Premium -- Electric Utilities (US)

	[1] Average Authorized Electric ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
2012.3	9.78%	2.74%	7.04%
2012.4	10.07%	2.86%	7.21%
2013.1	9.77%	3.13%	6.64%
2013.2	9.84%	3.14%	6.70%
2013.3	9.83%	3.71%	6.12%
2013.4	9.82%	3.79%	6.04%
2014.1	9.57%	3.69%	5.88%
2014.2	9.83%	3.44%	6.39%
2014.3	9.79%	3.26%	6.52%
2014.4	9.78%	2.96%	6.81%
2015.1	9.66%	2.55%	7.11%
2015.2	9.50%	2.88%	6.61%
2015.3	9.40%	2.96%	6.44%
2015.4	9.65%	2.96%	6.69%
2016.1	9.70%	2.72%	6.98%
2016.2	9.41%	2.57%	6.84%
2016.3	9.76%	2.28%	7.48%
2016.4	9.55%	2.83%	6.72%
2017.1	9.61%	3.04%	6.57%
2017.2	9.61%	2.90%	6.71%
2017.3	9.73%	2.82%	6.91%
2017.4	9.74%	2.82%	6.92%
2018.1	9.59%	3.02%	6.57%
2018.2	9.57%	3.09%	6.49%
2018.3	9.66%	3.06%	6.60%
2018.4	9.44%	3.27%	6.17%
2019.1	9.57%	3.01%	6.56%
2019.2	9.58%	2.78%	6.79%
2019.3	9.57%	2.29%	7.28%
2019.4	9.74%	2.25%	7.49%
2020.1	9.45%	1.89%	7.56%
2020.2	9.52%	1.38%	8.14%
2020.3	9.34%	1.37%	7.98%
2020.4	9.32%	1.62%	7.70%
2021.1	9.45%	2.07%	7.38%
2021.2	9.46%	2.25%	7.20%
2021.3	9.37%	1.93%	7.44%
2021.4	9.37%	1.94%	7.43%
2022.1	9.34%	2.25%	7.09%
2022.2	9.35%	3.03%	6.32%
2022.3	9.14%	3.26%	5.88%
2022.4	9.72%	3.88%	5.84%
2023.1	9.71%	3.74%	5.97%
2023.2	9.54%	3.80%	5.74%
2023.3	9.63%	4.23%	5.41%
2023.4	9.68%	4.58%	5.09%
2024.1	9.66%	4.32%	5.34%
2024.2	9.75%	4.65%	5.10%
AVERAGE	10.47%	4.54%	5.93%
MEDIAN	10.38%	4.58%	5.95%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.892945751
R Square	0.797352114
Adjusted R Square	0.795768928
Standard Error	0.004435103
Observations	130

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.009906621	0.009906621	503.6374813	3.36752E-46
Residual	128	0.002517778	1.96701E-05		
Total	129	0.012424399			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	0.083865706	0.001159715	72.31579959	1.1485E-105	0.081571012	0.0861604
U.S. Govt. 30-year Treasury	-0.540413521	0.024080593	-22.44186893	3.36752E-46	-0.588061089	-0.492766

	[7] U.S. Govt. 30-year Treasury	[8] Risk Premium	[9] ROE
Current 30-day average of 30-year U.S. Treasury bond yield [4]	4.59%	5.91%	10.50%
Blue Chip Near-Term Projected Forecast (Q3 2024 - Q3 2025) [5]	4.32%	6.05%	10.37%
Blue Chip Long-Term Projected Forecast (2025-2029) [6]	4.10%	6.17%	10.27%
AVERAGE			10.38%

Notes:
[1] Source: Regulatory Research Associates, rate cases through April 30, 2024
[2] Source: Bloomberg Professional, quarterly bond yields are the average of each trading day in the quarter
[3] Equals Column [1] − Column [2]
[4] Source: Bloomberg Professional, 30-day average as of April 30, 2024
[5] Source: Blue Chip Financial Forecasts, Vol. 43, No. 5, May 1, 2024 at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 42, No. 12, December 1, 2023 at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.083866 + (-0.540414 x Column [7])
[9] Equals Column [7] + Column [8]

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of
James M. Coyne and Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 2507

June 4, 2024

NW Natural/2507
Coyne-Nelson/Page 1

Exhibit NW Natural/2507
Page 1 of 1

EXPECTED EARNINGS ANALYSIS

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	Value Line ROE 2027-2029	Value Line Total Capital 2023	Value Line Common Equity Ratio 2023	Total Equity 2023	Value Line Total Capital 2027-2029	Value Line Common Equity Ratio 2027-2029	Total Equity 2027-2029	Compound Annual Growth Rate	Adjustment Factor	Adjusted Return on Common Equity
Atmos Energy Corporation	ATO	10.00%	17,509	62.10%	10,873	24,350	60.00%	14,610	6.09%	1.030	10.30%
New Jersey Resources Corporation	NJR	13.00%	4,759	41.80%	1,989	6,000	45.00%	2,700	6.30%	1.031	13.40%
NiSource Inc.	NI	11.00%	19,000	35.00%	6,650	22,500	37.50%	8,438	4.88%	1.024	11.26%
ONE Gas, Inc.	OGS	8.50%	4,500	58.00%	2,610	7,000	49.00%	3,430	5.62%	1.027	8.73%
Southwest Gas Holding	SWX	7.50%	9,000	40.00%	3,600	10,000	43.00%	4,300	3.62%	1.018	7.63%
Spire, Inc.	SR	8.50%	6,471	41.30%	2,673	9,100	45.00%	4,095	8.91%	1.043	8.86%
Ameren Corporation	AEE	10.00%	24,950	43.80%	10,928	29,500	48.50%	14,308	5.54%	1.027	10.27%
Avista Corporation	AVA	8.50%	5,091	48.80%	2,485	6,000	49.50%	2,970	3.63%	1.018	8.65%
Black Hills Corporation	BKH	8.50%	7,017	45.80%	3,214	9,525	44.00%	4,191	5.45%	1.027	8.73%
CenterPoint Energy, Inc.	CNP	9.50%	27,226	35.50%	9,665	32,100	40.00%	12,840	5.85%	1.028	9.77%
CMS Energy Corporation	CMS	13.00%	22,114	33.10%	7,320	24,400	36.50%	8,906	4.00%	1.020	13.25%
DTE Energy Company	DTE	12.50%	26,282	38.00%	9,987	32,200	39.00%	12,558	4.69%	1.023	12.79%
NorthWestern Energy Group, Inc.	NWE	8.00%	5,475	50.90%	2,787	6,700	49.50%	3,317	3.54%	1.017	8.14%
Public Service Enterprise Group Inc.	PEG	12.50%	31,200	46.00%	14,352	40,200	45.00%	18,090	4.74%	1.023	12.79%
Southern Company	SO	14.50%	83,500	36.00%	30,060	93,500	37.00%	34,595	2.85%	1.014	14.70%
Wisconsin Energy Corporation	WEC	13.00%	26,279	44.50%	11,694	29,800	44.50%	13,261	2.55%	1.013	13.16%
Gas Proxy Group Mean											10.03%
Gas Proxy Group Median											9.58%
Combined Proxy Group Mean											10.78%
Combined Proxy Group Median											10.28%

Notes:
[1] Source: Value Line
[2] Source: Value Line
[3] Source: Value Line
[4] Equals [2] x [3]
[5] Source: Value Line
[6] Source: Value Line
[7] Equals [5] x [6]
[8] Equals ([7] / [4]) ^ (1/5) - 1
[9] Equals 2 x (1 + [8]) / (2 + [8])
[10] Equals [1] x [9]

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

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RETURN ON EQUITY
EXHIBIT 2508

June 4, 2024

NW Natural/2508
Coyne-Nelson/Page 1

				STAFF/101, Muldoon/4 - AS FILED				Spot Closing Price from Yahoo! Finance			
				Yahoo Finance Q1 2024				Yahoo Finance Q1 2024			
				$ Stock Closing Price 1st Trading Day of Month			*3-Day Avg $ Stock Price*	$ Stock Closing Price 1st Trading Day of Month			*3-Day Avg $ Stock Price*
Line No.	#	Abbreviated Utility	Ticker	Feb. 2/1/2023	Mar. 3/1/2024	Apr. 4/1/2024		Feb. 2/1/2024	Mar. 3/1/2024	Apr. 4/1/2024	
1	**1**	Atmos	ATO	112.91	118.87	116.23	116.00	115.79	112.73	117.85	115.46
2	**3**	New Jersey	NJR	41.61	42.91	42.78	42.43	41.46	41.77	42.66	41.96
3	**4**	NiSource	NI	26.06	27.66	27.19	26.97	26.35	26.13	27.48	26.65
4	**5**	NW Natural	NWN	36.74	37.22	26.41	33.46	37.03	36.93	37.12	37.03
5	**6**	ONE Gas	OGS	59.60	64.53	63.72	62.62	61.90	59.48	63.62	61.67
6	**8**	Southwest Gas	SWX	68.15	76.13	74.54	72.94	59.93	69.61	75.58	68.37
7	**9**	Spire	SR	59.32	61.37	59.34	60.01	59.27	59.61	60.95	59.94

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

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RETURN ON EQUITY
EXHIBIT 2509

June 4, 2024

NW Natural/2509
Coyne-Nelson/Page 1

Gross Domestic Product by Industry

Industry	1947	2023	CAGR
Agriculture, forestry, fishing, and hunting	19.9	251.7	3.40%
Mining	5.8	380.9	5.66%
Utilities	3.5	434.3	6.55%
Construction	8.9	1,203.8	6.67%
Manufacturing	63.4	2,804.7	5.11%
Wholesale trade	15.6	1,613.7	6.29%
Retail trade	23.2	1,738.5	5.84%
Transportation and warehousing	14.1	970.5	5.73%
Information	7.7	1,475.1	7.16%
Finance, insurance, real estate, rental, and leasing	25.8	5,656.5	7.35%
Professional and business services	8.2	3,543.9	8.31%
Educational services, health care, and social assistance	4.6	2,351.6	8.55%
Arts, entertainment, recreation, accommodation, and food services	8.0	1,231.3	6.85%
Other services, except government	7.5	597.0	5.93%
Government	33.5	3,107.4	6.14%
Total Gross Domestic Product	249.7	27,360.9	6.37%

Source: Bureau of Economic Analysis.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

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RETURN ON EQUITY
EXHIBIT 2510

June 4, 2024

NW Natural/2510
Coyne-Nelson/Page 1

Staff's CAPM Analysis Corrected to Use Staff's Historical Arithmetic Average Total Market Return (1993-2023)

Company	Ticker	NWN Proxy Group [1]	Staff Proxy Group	Staff Risk-Free Rate	VL Beta	Staff Market Return (As Filed)	Staff CAPM ROE (As Filed)	Staff's Arithmetic Average Total Market Return (NWN DR No. 22)	Staff Corrected CAPM ROE
Atmos Energy Corporation	ATO	Yes	Yes	4.555%	0.85	9.90%	9.10%	10.83%	9.89%
New Jersey Resources Corporation	NJR	Yes	No	4.555%	0.95	9.90%	9.63%	10.83%	10.51%
NiSource Inc.	NI	Yes	Yes	4.555%	0.90	9.90%	9.37%	10.83%	10.20%
Northwest Natural Holding Company	NWN	No	Yes	4.555%	0.85	9.90%	9.10%	10.83%	9.89%
ONE Gas, Inc.	OGS	Yes	Yes	4.555%	0.85	9.90%	9.10%	10.83%	9.89%
Southwest Gas Holding	SWX	Yes	Yes	4.555%	0.90	9.90%	9.37%	10.83%	10.20%
Spire Inc.	SR	Yes	Yes	4.555%	0.85	9.90%	9.10%	10.83%	9.89%
Average CAPM ROE Using Staff's Proxy Group							9.19%		9.99%
Average CAPM ROE Using NWN's Proxy Group							9.28%		10.10%

Sources: Staff/104, Muldoon/1 and Staff's response NWN DR 22 Attachment A

[1] Staff's analysis includes NWN in the Company's proxy group in error. The error has been corrected here.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of
James M. Coyne and Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 2511

June 4, 2024

NW Natural/2511
Coyne-Nelson/Page 1

Staff's Single Stage DCF Analysis Corrected to Use Value Line's Published Dividend Growth Rate Projections

		As Filed in Staff/105, Muldoon/1							Corrected	
Company	Ticker	NWN Proxy [1]	Staff Proxy	Recent Stock Price [2]	Next VL Annual Dividend	Anticpated Dividend Yield	Staff's Calculated VL Dividend Growth	Staff's Constant Growth DCF ROE	Corrected VL 3-to 5-yr Proj. Dividend Growth [3]	Corrected Constant Growth DCF ROE
Atmos Energy Corporation	ATO	Yes	Yes	$ 116.00	$ 3.22	2.8%	7.3%	10.1%	7.50%	10.28%
New Jersey Resources Corporation	NJR	Yes	No	$ 42.43	$ 1.68	4.0%	5.0%	8.9%	5.00%	8.96%
NiSource Inc.	NI	Yes	Yes	$ 26.97	$ 1.06	3.9%	4.2%	8.1%	4.50%	8.43%
Northwest Natural Holding Company	NWN	No	Yes	$ 33.46	$ 1.95	5.8%	0.4%	6.2%	0.50%	6.33%
ONE Gas, Inc.	OGS	Yes	Yes	$ 62.62	$ 2.64	4.2%	2.4%	6.7%	3.00%	7.22%
Southwest Gas Holding	SWX	Yes	Yes	$ 72.94	$ 2.48	3.4%	1.1%	4.5%	5.50%	8.90%
Spire Inc.	SR	Yes	Yes	$ 60.01	$ 3.02	5.0%	4.7%	9.7%	4.50%	9.53%
										Difference
Average CAPM ROE Using Staff's Proxy Group								7.54%		8.45% 0.91%
Average CAPM ROE Using NWN's Proxy Group								7.99%		8.89% 0.89%

Sources:
Staff/105, Muldoon/1

Notes:
[1] Staff's analysis includes NWN in the Company's Proxy Group in error. The error has been corrected here.

[2] As shown in Exhibit NW Natural/2508, Staff's 3-day average stock prices do not reconcile with the closing prices on Staff's selected dates. This analysis uses Staff's stock prices as filed.

[3] Source: Value Line Investment Survey quarterly company reports published as of 4/30/2024

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of
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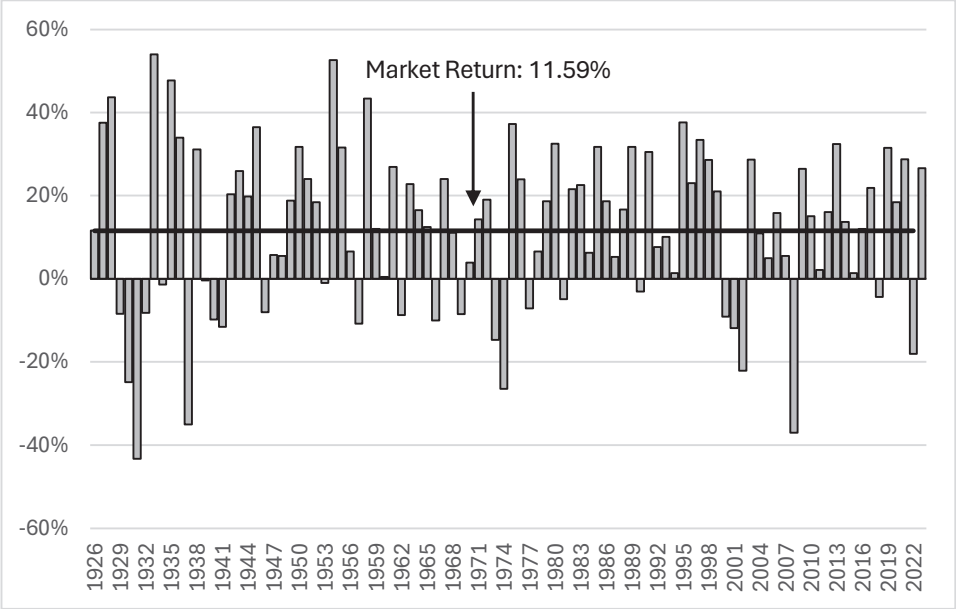
RETURN ON EQUITY
EXHIBIT 2512

June 4, 2024

Annual Total Return on Large Company Stocks, 1926 - 2023



Source: Kroll, 2023 SBBI Yearbook, Appendix A-1, A-7 (years 1926-2022); Cost of Capital Navigator (2023 data)

	Large Company Stocks Total Returns	Long-Term Government Bond Income Returns	**Annual MRP**
Year	**Jan-Dec***	**Jan-Dec***	
1926	0.1162	0.0373	0.0789
1927	0.3749	0.0341	0.3408
1928	0.4361	0.0322	0.4039
1929	-0.0842	0.0347	-0.1189
1930	-0.2490	0.0332	-0.2822
1931	-0.4334	0.0333	-0.4667
1932	-0.0819	0.0369	-0.1188
1933	0.5399	0.0312	0.5087
1934	-0.0144	0.0318	-0.0462
1935	0.4767	0.0281	0.4486
1936	0.3392	0.0277	0.3115
1937	-0.3503	0.0266	-0.3769
1938	0.3112	0.0264	0.2848
1939	-0.0041	0.0240	-0.0281
1940	-0.0978	0.0223	-0.1201
1941	-0.1159	0.0194	-0.1353
1942	0.2034	0.0246	0.1788
1943	0.2590	0.0244	0.2346
1944	0.1975	0.0246	0.1729
1945	0.3644	0.0234	0.3410

1946	-0.0807	0.0204	-0.1011
1947	0.0571	0.0213	0.0358
1948	0.0550	0.0240	0.0310
1949	0.1879	0.0225	0.1654
1950	0.3171	0.0212	0.2959
1951	0.2402	0.0238	0.2164
1952	0.1837	0.0266	0.1571
1953	-0.0099	0.0284	-0.0383
1954	0.5262	0.0279	0.4983
1955	0.3156	0.0275	0.2881
1956	0.0656	0.0299	0.0357
1957	-0.1078	0.0344	-0.1422
1958	0.4336	0.0327	0.4009
1959	0.1196	0.0401	0.0795
1960	0.0047	0.0426	-0.0379
1961	0.2689	0.0383	0.2306
1962	-0.0873	0.0400	-0.1273
1963	0.2280	0.0389	0.1891
1964	0.1648	0.0415	0.1233
1965	0.1245	0.0419	0.0826
1966	-0.1006	0.0449	-0.1455
1967	0.2398	0.0459	0.1939
1968	0.1106	0.0550	0.0556
1969	-0.0850	0.0595	-0.1445
1970	0.0386	0.0674	-0.0288
1971	0.1430	0.0632	0.0798
1972	0.1900	0.0587	0.1313
1973	-0.1469	0.0651	-0.2120
1974	-0.2647	0.0727	-0.3374
1975	0.3723	0.0799	0.2924
1976	0.2393	0.0789	0.1604
1977	-0.0716	0.0714	-0.1430
1978	0.0657	0.0790	-0.0133
1979	0.1861	0.0886	0.0975
1980	0.3250	0.0997	0.2253
1981	-0.0492	0.1155	-0.1647
1982	0.2155	0.1350	0.0805
1983	0.2256	0.1038	0.1218
1984	0.0627	0.1174	-0.0547
1985	0.3173	0.1125	0.2048
1986	0.1867	0.0898	0.0969
1987	0.0525	0.0792	-0.0267
1988	0.1661	0.0897	0.0764
1989	0.3169	0.0881	0.2288
1990	-0.0310	0.0819	-0.1129
1991	0.3047	0.0822	0.2225
1992	0.0762	0.0726	0.0036

1993	0.1008	0.0717	0.0291
1994	0.0132	0.0659	-0.0527
1995	0.3758	0.0760	0.2998
1996	0.2296	0.0618	0.1678
1997	0.3336	0.0664	0.2672
1998	0.2858	0.0583	0.2275
1999	0.2104	0.0557	0.1547
2000	-0.0910	0.0650	-0.1560
2001	-0.1189	0.0553	-0.1742
2002	-0.2210	0.0559	-0.2769
2003	0.2868	0.0480	0.2388
2004	0.1088	0.0502	0.0586
2005	0.0491	0.0469	0.0022
2006	0.1579	0.0468	0.1111
2007	0.0549	0.0486	0.0063
2008	-0.3700	0.0445	-0.4145
2009	0.2646	0.0347	0.2299
2010	0.1506	0.0425	0.1081
2011	0.0211	0.0382	-0.0171
2012	0.1600	0.0246	0.1354
2013	0.3239	0.0288	0.2951
2014	0.1369	0.0341	0.1028
2015	0.0138	0.0247	-0.0109
2016	0.1196	0.0230	0.0966
2017	0.2183	0.0267	0.1916
2018	-0.0438	0.0282	-0.0720
2019	0.3149	0.0255	0.2894
2020	0.1840	0.0142	0.1698
2021	0.2871	0.0173	0.2698
2022	-0.1811	0.0261	-0.2072
2023	0.2661	0.0417	0.2244
Avg 1926-2023	0.1217	0.0484	0.0732
Std. Dev.	0.1973	0.0263	0.1985

Avg 1926-1994: 0.1217

1994-2023 count

>= 11.59%	18	60.00%

Historical Market Return 1926-2023

	# Occurrences	
11.59%	55	56.12%
	98	

Note:

Kroll revised its methodology in 2024 for calculating the long-term historical average return on large-cap stocks, the income return on long-term government bonds, and the resulting long-term historical average market risk premium. Thus the average based on annual data shown above does not precisely match Kroll's revised long-term arithmetic average market risk premium.

Kroll's revised historical average market risk premium between 1926-2023 is shown below:

Based on the new equity and bond series discussed above, here is the U.S. Historical ERP for 1926−2023 and its respective components:

Equities	Bonds	ERP
CRSP S&P 500 Total Returns Average Annual Return (1926−2023)	Synthetic 20-Year U.S. Treasury Bond Income Returns Average Annual Return (1926−2023)	U.S. Historical ERP (1926−2023)
12.04%	**4.87%**	**7.17%**

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of
James M. Coyne and Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 2513

June 4, 2024

Date: May 16, 2024

TO:

Eric Nelsen
Northwest Natural Gas
220 NW Second Avenue
Portland, OR 97209

Lisa Rackner or Jocelyn Pease
McDowell, Rackner & Gibson
419 SW Eleventh Ave., Suite 400
Portland, OR 97205
lisa@mrg-law.com or jocelyn@mrg-law.co

FROM: Matt Muldoon, Mgr. Accounting and Finance

OREGON PUBLIC UTILITY COMMISSION
Docket No. UG 490 – NWN Data Request No 20.

Data Request No 20:
Referring to Staff/100, Muldoon/20 lines 9-14 and Muldoon/21, lines 10-11:
a. Please explain why Staff does not think that the consideration of electric utilities with natural gas utilities is "informative for the Commission" but consideration of water utilities would be informative.

Staff Response No 20:

Re: Staff/100, Muldoon/20 lines 9-14 and Muldoon/21, lines 10-11:

a. Electric and natural gas utilities have divergent risk profiles in part due to the nature of their operations. This can be seen by reviewing credit rating report and SEC filings including Annual Reports posted on the U.S. Security and Exchange Commission's Edgar resource, accessible to the public at: https://www.sec.gov/edgar/search-and-access .

It is uncertain whether publicly traded water utilities have close enough characteristics to merit future inclusion in ROE modeling for Commission jurisdictional natural gas utilities. That is why Staff proposes to track water utilities in its natural gas ROE modeling to acquire over time more information for which to make such an assessment. While Staff was informed by NW Natural leadership that there is significant overlap in operational profiles for the Company and water utilities when NW Natural was forming a holding company in part for the acquisition of water utilities, Staff will need to acquire significantly more data over time before making any recommendation to the Commission in this regard.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of
James M. Coyne and Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 2514

June 4, 2024

UG 490– PUC Response to NWN Data Request 22
Page 1

Date: May 16, 2024

TO:

Eric Nelsen
Northwest Natural Gas
220 NW Second Avenue
Portland, OR 97209

Lisa Rackner or Jocelyn Pease
McDowell, Rackner & Gibson
419 SW Eleventh Ave., Suite 400
Portland, OR 97205
lisa@mrg-law.com or jocelyn@mrg-law.cor

FROM: Matt Muldoon, Mgr. Accounting and Finance

OREGON PUBLIC UTILITY COMMISSION
Docket No. UG 490 – NWN Data Request No 22.

Data Request No 22:
Referring to Staff/100, Muldoon/23 and Staff/104, Muldoon/1.
a. Please explain whether Staff's risk-free rate of 4.555% is a spot yield as of April 5, 2024, or an average yield. If it is an average yield, please explain over what period the average was calculated and provide all underlying data to support the average calculation.
b. Please explain why Staff relied on an S&P 500 market return between 1993 through 2023 to develop its market risk premium. Provide any analyses and studies relied on by Staff that support the use of a 31-year historical period to develop a forward-looking expected market return.
c. Please provide the underlying data used to calculate the 9.90% market return between 1990-2023 and include the source of the data.
d. Please explain whether the 9.90% market return between 1993 and 2023 represents an arithmetic average or a geometric average.
e. Please explain whether the 9.90% market return reflects the total return, income return, or price appreciation.

Staff Response No 22:

Re: Staff/100, Muldoon/23 and Staff/104, Muldoon/1:

a. Staff's risk-free rate is a spot yield, consistent for this model. This is sourced as shown in Staff testimony from the Wall Street Journal.

b. Staff applies the fundamental accounting and finance "matching principle" within a given model. Note that the modeling periods match the periods herein.

c. Data to calculate a 9.9% market return between 1990 to 2023 is provided as Staff Response to **NWN DR 22 Attachment A**. This spreadsheet shows Staff's highlighted values.

d. The return from 1993 to 2023 was 9.85% which Staff rounded up slightly. Staff did not adjust this downward to account for inflation. For comparison, see the 9.08 geometric return for this period, and the overall average of approached of 9.75%. Staff understands that its use of 9.90 vs. a clearer 9.85% could create confusion.

e. Making the narrowing distinction between stock Price Return only or (PR) vs. stock Total Return (TR), Staff believes the Company is asking if Staff relies on the standard S&P 500 index (SPX) or the less used S&P 500 Total Return index (SPTR). Please see Staff response in **NWN DR 22 Attachment A** for the values Staff considered.

Period	Annualized Price Return			Annualized Total Return			**Average of Price and Total Returns**			Overall
	Arithmetic	Arith w/ mo. Comp	Geometric	Arithmetic	Arith w/ mo. Comp	Geometric	Arithmetic	Arith w/ mo. Comp	Geometric	Average
1990-2023	8.80%	9.16%	7.95%	10.87%	11.43%	10.19%	9.84%	10.30%	9.07%	9.74%
1993-2023	8.88%	9.25%	8.03%	10.83%	11.38%	10.14%	**9.85%**	10.31%	9.08%	9.75%

Date	Close Px	Dividends	Prc Appr	TR	Pd Appr	Pd Return
3/29/2024	5254.35	5.78978	4767.84%	15007.55%	3.10%	3.22%
2/29/2024	5096.27	7.98647	4621.39%	14536.63%	5.17%	5.34%
1/31/2024	4845.65	4.23131	4389.21%	13794.72%	1.59%	1.68%
12/29/2023	4769.83	4.85246	4318.96%	13565.23%	4.42%	4.53%
11/30/2023	4567.8	8.82372	4131.80%	12972.89%	8.92%	9.13%
10/31/2023	4193.8	4.16139	3785.31%	11878.90%	-2.20%	-2.10%
9/29/2023	4288.05	4.83818	3872.62%	12136.18%	-4.87%	-4.77%
8/31/2023	4507.66	8.12839	4076.08%	12748.79%	-1.77%	-1.59%
7/31/2023	4588.96	4.28904	4151.40%	12956.67%	3.11%	3.21%
6/30/2023	4450.38	5.48991	4023.01%	12550.28%	6.47%	6.61%
5/31/2023	4179.83	7.72067	3772.36%	11766.23%	0.25%	0.43%
4/28/2023	4169.48	3.92206	3762.78%	11714.85%	1.46%	1.56%
3/31/2023	4109.31	6.29247	3707.03%	11533.27%	3.51%	3.67%
2/28/2023	3970.15	6.79986	3578.11%	11121.49%	-2.61%	-2.45%
1/31/2023	4076.6	3.97809	3676.73%	11403.21%	6.18%	6.28%
12/30/2022	3839.5	5.25298	3457.07%	10723.21%	-5.90%	-5.77%
11/30/2022	4080.11	7.91502	3679.98%	11386.12%	5.38%	5.59%
10/31/2022	3871.98	3.80717	3487.16%	10778.20%	7.99%	8.10%
9/30/2022	3585.62	5.42494	3221.86%	9963.44%	-9.34%	-9.21%
8/31/2022	3955	7.20541	3564.07%	10984.59%	-4.24%	-4.08%
7/29/2022	4130.29	3.9233	3726.47%	11455.87%	9.11%	9.22%
6/30/2022	3785.38	5.70104	3406.93%	10480.29%	-8.39%	-8.26%
5/31/2022	4132.15	7.19003	3728.19%	11432.61%	0.01%	0.18%
4/29/2022	4131.93	3.65935	3727.99%	11411.36%	-8.80%	-8.72%
3/31/2022	4530.41	5.68487	4097.16%	12511.04%	3.58%	3.71%
2/28/2022	4373.94	6.36784	3952.20%	12059.58%	-3.14%	-3.00%
1/31/2022	4515.55	4.05651	4083.39%	12435.26%	-5.26%	-5.17%
12/31/2021	4766.18	5.05513	4315.58%	13119.34%	4.36%	4.47%
11/30/2021	4567	6.50818	4131.05%	12553.13%	-0.83%	-0.70%
10/29/2021	4605.38	3.77788	4166.61%	12641.69%	6.91%	7.01%
9/30/2021	4307.54	4.88045	3890.68%	11807.55%	-4.76%	-4.65%
8/31/2021	4522.68	6.12657	4089.99%	12388.57%	2.90%	3.04%
7/30/2021	4395.26	4.28331	3971.95%	12020.04%	2.27%	2.38%
6/30/2021	4297.5	4.67043	3881.38%	11738.83%	2.22%	2.33%
5/31/2021	4204.11	6.18336	3794.86%	11468.79%	0.55%	0.70%
4/30/2021	4181.17	3.69177	3773.61%	11388.58%	5.24%	5.34%
3/31/2021	3972.89	5.04247	3580.65%	10806.52%	4.24%	4.38%
2/26/2021	3811.15	5.62762	3430.80%	10348.99%	2.61%	2.76%
1/29/2021	3714.24	3.66467	3341.02%	10068.58%	-1.11%	-1.02%
12/31/2020	3756.07	4.59273	3379.78%	10173.14%	3.71%	3.84%
11/30/2020	3621.63	6.16169	3255.23%	9793.11%	10.75%	10.95%
10/30/2020	3269.96	3.75784	2929.42%	8817.03%	-2.77%	-2.66%
9/30/2020	3363	4.31311	3015.62%	9060.65%	-3.92%	-3.80%
8/31/2020	3500.31	5.76577	3142.83%	9422.52%	7.01%	7.19%
7/31/2020	3271.12	3.87283	2930.50%	8783.92%	5.51%	5.64%
6/30/2020	3100.29	4.51772	2772.24%	8309.76%	1.84%	1.99%
5/29/2020	3044.31	6.54652	2720.37%	8145.82%	4.53%	4.76%
4/30/2020	2912.43	3.26257	2598.19%	7770.93%	12.68%	12.82%
3/31/2020	2584.59	4.86024	2294.47%	6876.58%	-12.51%	-12.35%
2/28/2020	2954.22	6.38965	2636.91%	7859.76%	-8.41%	-8.23%
1/31/2020	3225.52	3.89572	2888.25%	8573.79%	-0.16%	-0.04%
12/31/2019	3230.78	4.6742	2893.13%	8577.61%	2.86%	3.01%
11/29/2019	3140.98	6.76035	2809.93%	8323.97%	3.40%	3.63%
10/31/2019	3037.56	3.55031	2714.12%	8028.89%	2.04%	2.17%
9/30/2019	2976.74	4.46241	2657.77%	7856.57%	1.72%	1.87%
8/30/2019	2926.46	6.63476	2611.19%	7710.48%	-1.81%	-1.58%
7/31/2019	2980.38	3.67499	2661.15%	7836.19%	1.31%	1.44%
6/28/2019	2941.76	4.15062	2625.37%	7723.74%	6.89%	7.05%
5/31/2019	2752.06	6.80031	2449.62%	7208.70%	-6.58%	-6.35%
4/30/2019	2945.83	3.27262	2629.14%	7704.68%	3.93%	4.05%

pd appr is price appreciation from last period
pd return is tr

Bloomberg Data Function
Bloomberg Data (BBG) GO

3/29/2019	2834.4	4.12131	2525.90%	7400.97%	1.79%	1.94%
2/28/2019	2784.49	6.35421	2479.67%	7258.03%	2.97%	3.21%
1/31/2019	2704.1	3.48807	2405.19%	7029.13%	7.87%	8.01%
12/31/2018	2506.85	4.08824	2222.45%	6500.23%	-9.18%	-9.03%
11/30/2018	2760.17	6.76685	2457.13%	7155.70%	1.79%	2.04%
10/31/2018	2711.74	3.18704	2412.27%	7010.81%	-6.94%	-6.84%
9/28/2018	2913.98	4.00961	2599.63%	7532.51%	0.43%	0.57%
8/31/2018	2901.52	6.42007	2588.09%	7489.37%	3.03%	3.26%
7/31/2018	2816.29	3.20148	2509.13%	7249.89%	3.60%	3.72%
6/29/2018	2718.37	3.58419	2418.41%	6986.17%	0.48%	0.61%
5/31/2018	2705.27	6.54317	2406.27%	6942.88%	2.16%	2.41%
4/30/2018	2648.05	2.94757	2353.26%	6777.29%	0.27%	0.38%
3/30/2018	2640.87	4.07626	2346.61%	6751.01%	-2.69%	-2.54%
2/28/2018	2713.83	5.87011	2414.20%	6929.70%	-3.89%	-3.69%
1/31/2018	2823.81	2.7602	2516.09%	7198.73%	5.62%	5.72%
12/29/2017	2673.61	3.18199	2376.94%	6803.62%	0.98%	1.10%
11/30/2017	2647.58	6.52918	2352.83%	6728.24%	2.81%	3.07%
10/31/2017	2575.26	2.86208	2285.83%	6525.04%	2.22%	2.33%
9/29/2017	2519.36	3.21738	2234.04%	6373.98%	1.93%	2.06%
8/31/2017	2471.65	6.17013	2189.84%	6243.19%	0.05%	0.31%
7/31/2017	2470.3	2.90212	2188.59%	6223.83%	1.93%	2.06%
6/30/2017	2423.41	3.43432	2145.15%	6096.42%	0.48%	0.62%
5/31/2017	2411.8	5.90387	2134.39%	6058.04%	1.16%	1.41%
4/28/2017	2384.2	2.75519	2108.82%	5972.59%	0.91%	1.03%
3/31/2017	2362.72	3.66481	2088.92%	5910.85%	-0.04%	0.12%
2/28/2017	2363.64	5.61968	2089.77%	5903.90%	3.72%	3.97%
1/31/2017	2278.87	2.417	2011.24%	5674.62%	1.79%	1.90%
12/30/2016	2238.83	3.28784	1974.14%	5567.13%	1.82%	1.97%
11/30/2016	2198.81	5.96843	1937.07%	5457.70%	3.42%	3.70%
10/31/2016	2126.15	2.59411	1869.75%	5259.22%	-1.94%	-1.82%
9/30/2016	2168.27	3.04434	1908.77%	5358.80%	-0.12%	0.02%
8/31/2016	2170.95	5.71509	1911.26%	5357.83%	-0.12%	0.14%
7/29/2016	2173.6	2.5758	1913.71%	5350.16%	3.56%	3.69%
6/30/2016	2098.86	3.51464	1844.47%	5156.39%	0.09%	0.26%
5/31/2016	2096.96	5.30451	1842.71%	5142.78%	1.53%	1.79%
4/29/2016	2065.3	2.43896	1813.38%	5050.37%	0.27%	0.39%
3/31/2016	2059.74	3.48431	1808.23%	5030.46%	6.60%	6.78%
2/29/2016	1932.23	5.26521	1690.10%	4704.54%	-0.41%	-0.14%
1/29/2016	1940.24	2.27008	1697.52%	4711.08%	-5.07%	-4.96%
12/31/2015	2043.94	3.48655	1793.59%	4962.30%	-1.75%	-1.59%
11/30/2015	2080.41	5.1109	1827.38%	5043.90%	0.05%	0.30%
10/30/2015	2079.36	2.54146	1826.40%	5028.69%	8.30%	8.44%
9/30/2015	1920.03	3.39245	1678.79%	4629.73%	-2.64%	-2.47%
8/31/2015	1972.18	4.90111	1727.11%	4749.71%	-6.26%	-6.03%
7/31/2015	2103.84	2.47789	1849.08%	5061.17%	1.97%	2.10%
6/30/2015	2063.11	3.54538	1811.35%	4955.24%	-2.10%	-1.94%
5/29/2015	2107.39	4.93666	1852.37%	5055.03%	1.05%	1.29%
4/30/2015	2085.51	2.19441	1832.10%	4989.57%	0.85%	0.96%
3/31/2015	2067.89	3.3412	1815.78%	4941.27%	-1.74%	-1.58%
2/27/2015	2104.5	5.05332	1849.69%	5022.26%	5.49%	5.75%
1/30/2015	1994.99	2.1384	1748.24%	4743.93%	-3.10%	-3.00%
12/31/2014	2058.9	3.34012	1807.45%	4893.84%	-0.42%	-0.26%
11/28/2014	2067.56	4.65978	1815.47%	4906.72%	2.45%	2.69%
10/31/2014	2018.05	2.31421	1769.60%	4775.70%	2.32%	2.44%
9/30/2014	1972.29	3.02293	1727.21%	4659.47%	-1.55%	-1.40%
8/29/2014	2003.37	4.40125	1756.00%	4727.16%	3.77%	4.00%
7/31/2014	1930.67	2.57169	1688.65%	4541.53%	-1.51%	-1.38%
6/30/2014	1960.23	3.0483	1716.04%	4606.44%	1.91%	2.07%
5/30/2014	1923.57	4.4798	1682.07%	4511.18%	2.10%	2.35%
4/30/2014	1883.95	2.20191	1645.37%	4405.50%	0.62%	0.74%
3/31/2014	1872.34	2.73168	1634.61%	4372.45%	0.69%	0.84%
2/28/2014	1859.45	4.52139	1622.67%	4335.16%	4.31%	4.57%

1/31/2014	1782.59	1.90752	1551.46%	4141.22%	-3.56%	-3.46%
12/31/2013	1848.36	2.97174	1612.40%	4293.11%	2.36%	2.52%
11/29/2013	1805.81	4.17098	1572.98%	4184.93%	2.80%	3.05%
10/31/2013	1756.54	2.22328	1527.33%	4058.27%	4.46%	4.60%
9/30/2013	1681.55	2.63323	1457.86%	3875.54%	2.97%	3.14%
8/30/2013	1632.97	4.00469	1412.85%	3754.65%	-3.13%	-2.90%
7/31/2013	1685.73	2.24145	1461.73%	3869.70%	4.95%	5.09%
6/28/2013	1606.28	2.57647	1388.12%	3677.48%	-1.50%	-1.34%
5/31/2013	1630.74	4.18504	1410.78%	3728.89%	2.08%	2.34%
4/30/2013	1597.57	1.81552	1380.05%	3641.45%	1.81%	1.93%
3/29/2013	1569.19	2.27209	1353.76%	3570.73%	3.60%	3.75%
2/28/2013	1514.68	3.75121	1303.26%	3438.04%	1.11%	1.36%
1/31/2013	1498.11	1.91549	1287.91%	3390.67%	5.04%	5.18%
12/31/2012	1426.19	2.81278	1221.28%	3218.79%	0.71%	0.91%
11/30/2012	1416.18	4.07523	1212.01%	3188.98%	0.28%	0.58%
10/31/2012	1412.16	1.87441	1208.28%	3170.05%	-1.98%	-1.85%
9/28/2012	1440.67	2.24523	1234.70%	3231.56%	2.42%	2.58%
8/31/2012	1406.58	3.80182	1203.11%	3147.65%	1.98%	2.25%
7/31/2012	1379.32	1.73376	1177.86%	3076.08%	1.26%	1.39%
6/29/2012	1362.16	2.09316	1161.96%	3032.59%	3.96%	4.12%
5/31/2012	1310.33	3.64595	1113.94%	2908.62%	-6.27%	-6.01%
4/30/2012	1397.91	1.70648	1195.08%	3101.00%	-0.75%	-0.63%
3/30/2012	1408.47	2.03936	1204.86%	3121.23%	3.13%	3.29%
2/29/2012	1365.68	3.44227	1165.22%	3018.77%	4.06%	4.32%
1/31/2012	1312.41	1.53071	1115.87%	2889.50%	4.36%	4.48%
12/30/2011	1257.61	2.05851	1065.10%	2761.28%	0.85%	1.02%
11/30/2011	1246.96	3.51713	1055.23%	2732.36%	-0.51%	-0.22%
10/31/2011	1253.3	1.66264	1061.11%	2738.66%	10.77%	10.93%
9/30/2011	1131.42	1.85573	948.19%	2458.98%	-7.18%	-7.03%
8/31/2011	1218.89	3.08882	1029.23%	2652.47%	-5.68%	-5.43%
7/29/2011	1292.28	1.54063	1097.22%	2810.61%	-2.15%	-2.03%
6/30/2011	1320.64	2.07917	1123.50%	2871.04%	-1.83%	-1.67%
5/31/2011	1345.2	2.94963	1146.25%	2921.41%	-1.35%	-1.13%
4/29/2011	1363.61	1.44351	1163.30%	2956.01%	2.85%	2.96%
3/31/2011	1325.83	1.90216	1128.30%	2868.13%	-0.10%	0.04%
2/28/2011	1327.22	2.9342	1129.59%	2866.94%	3.20%	3.43%
1/31/2011	1286.12	1.31607	1091.51%	2768.68%	2.26%	2.37%
12/31/2010	1257.64	1.78858	1065.13%	2702.28%	6.53%	6.68%
11/30/2010	1180.55	2.89445	993.71%	2526.71%	-0.23%	0.01%
10/29/2010	1183.26	1.34264	996.22%	2526.40%	3.69%	3.80%
9/30/2010	1141.2	1.73693	957.25%	2430.13%	8.76%	8.92%
8/31/2010	1049.33	2.62787	872.14%	2222.84%	-4.74%	-4.51%
7/30/2010	1101.6	1.28457	920.57%	2332.67%	6.88%	7.01%
6/30/2010	1030.71	1.7442	854.89%	2173.39%	-5.39%	-5.24%
5/31/2010	1089.41	2.61966	909.27%	2298.99%	-8.20%	-7.98%
4/30/2010	1186.69	1.19676	999.40%	2507.17%	1.48%	1.58%
3/31/2010	1169.43	1.68464	983.41%	2466.67%	5.88%	6.03%
2/26/2010	1104.49	2.57872	923.24%	2320.59%	2.85%	3.10%
1/29/2010	1073.87	1.17724	894.88%	2247.91%	-3.70%	-3.60%
12/31/2009	1115.1	1.68335	933.07%	2335.52%	1.78%	1.93%
11/30/2009	1095.63	2.65999	915.04%	2289.37%	5.74%	5.99%
10/30/2009	1036.2	1.26276	859.98%	2154.25%	-1.98%	-1.86%
9/30/2009	1057.08	1.59751	879.32%	2196.94%	3.57%	3.73%
8/31/2009	1020.63	2.4417	845.55%	2114.33%	3.36%	3.61%
7/31/2009	987.48	1.27042	814.84%	2037.21%	7.41%	7.56%
6/30/2009	919.32	1.65549	751.70%	1886.93%	0.02%	0.20%
5/29/2009	919.14	2.40503	751.53%	1883.01%	5.31%	5.59%
4/30/2009	872.81	1.34164	708.61%	1778.03%	9.39%	9.57%
3/31/2009	797.87	1.49324	639.18%	1614.01%	8.54%	8.76%
2/27/2009	735.09	3.13522	581.02%	1475.96%	-10.99%	-10.65%
1/30/2009	825.88	1.32857	665.13%	1663.76%	-8.57%	-8.43%
12/31/2008	903.25	2.42826	736.81%	1826.10%	0.78%	1.06%

11/28/2008	896.24	2.97505	730.31%	1805.85%	-7.48%	-7.17%
10/31/2008	968.75	1.74421	797.49%	1953.16%	-16.94%	-16.80%
9/30/2008	1166.36	2.28175	980.56%	2367.60%	-9.08%	-8.91%
8/29/2008	1282.83	2.8934	1088.47%	2609.01%	1.22%	1.45%
7/31/2008	1267.38	1.85559	1074.15%	2570.38%	-0.99%	-0.84%
6/30/2008	1280	2.42696	1085.84%	2593.02%	-8.60%	-8.43%
5/30/2008	1400.38	3.15428	1197.37%	2840.97%	1.07%	1.30%
4/30/2008	1385.59	1.5146	1183.67%	2803.37%	4.75%	4.87%
3/31/2008	1322.7	2.16508	1125.40%	2668.52%	-0.60%	-0.43%
2/29/2008	1330.63	3.17304	1132.75%	2680.54%	-3.48%	-3.25%
1/31/2008	1378.55	1.74686	1177.15%	2773.91%	-6.12%	-6.00%
12/31/2007	1468.36	2.46601	1260.35%	2957.30%	-0.86%	-0.70%
11/30/2007	1481.14	4.60067	1272.19%	2978.77%	-4.40%	-4.10%
10/31/2007	1549.38	1.65175	1335.41%	3110.50%	1.48%	1.59%
9/28/2007	1526.75	2.2917	1314.44%	3060.24%	3.58%	3.74%
8/31/2007	1473.99	3.06307	1265.56%	2946.34%	1.29%	1.50%
7/31/2007	1455.28	1.52503	1248.23%	2901.35%	-3.20%	-3.10%
6/29/2007	1503.35	1.84092	1292.76%	2997.38%	-1.78%	-1.66%
5/31/2007	1530.62	3.41459	1318.03%	3049.74%	3.25%	3.49%
4/30/2007	1482.37	1.40868	1273.33%	2943.56%	4.33%	4.43%
3/30/2007	1420.86	1.64338	1216.34%	2814.45%	1.00%	1.12%
2/28/2007	1406.82	3.37628	1203.34%	2782.26%	-2.18%	-1.96%
1/31/2007	1438.24	1.48774	1232.44%	2839.74%	1.41%	1.51%
12/29/2006	1418.3	1.85347	1213.97%	2795.95%	1.26%	1.39%
11/30/2006	1400.63	3.47731	1197.60%	2756.14%	1.65%	1.90%
10/31/2006	1377.94	1.41402	1176.58%	2702.83%	3.15%	3.26%
9/29/2006	1335.85	1.51584	1137.59%	2614.39%	2.46%	2.57%
8/31/2006	1303.82	3.16975	1107.91%	2546.26%	2.13%	2.38%
7/31/2006	1276.66	1.36899	1082.75%	2484.76%	0.51%	0.62%
6/30/2006	1270.2	1.54396	1076.77%	2468.91%	0.01%	0.13%
5/31/2006	1270.09	2.84595	1076.66%	2465.50%	-3.09%	-2.88%
4/28/2006	1310.61	1.59517	1114.20%	2541.53%	1.22%	1.34%
3/31/2006	1294.83	1.74956	1099.58%	2506.54%	1.11%	1.24%
2/28/2006	1280.66	2.87976	1086.46%	2474.51%	0.04%	0.27%
1/31/2006	1280.09	1.26113	1085.93%	2467.57%	2.55%	2.65%
12/30/2005	1248.29	1.58264	1056.47%	2401.33%	-0.10%	0.03%
11/30/2005	1249.48	3.13605	1057.57%	2400.58%	3.52%	3.78%
10/31/2005	1207.01	1.30394	1018.22%	2309.45%	-1.77%	-1.67%
9/30/2005	1228.81	1.39916	1038.42%	2350.29%	0.69%	0.81%
8/31/2005	1220.33	2.59776	1030.56%	2330.60%	-1.12%	-0.91%
7/29/2005	1234.18	1.4355	1043.39%	2352.98%	3.60%	3.72%
6/30/2005	1191.33	1.87689	1003.70%	2265.03%	-0.01%	0.14%
5/31/2005	1191.5	2.12652	1003.85%	2261.68%	3.00%	3.18%
4/29/2005	1156.85	1.36026	971.75%	2188.85%	-2.01%	-1.90%
3/31/2005	1180.59	1.71878	993.75%	2233.10%	-1.91%	-1.77%
2/28/2005	1203.6	2.51539	1015.06%	2275.16%	1.89%	2.10%
1/31/2005	1181.27	1.1096	994.38%	2226.21%	-2.53%	-2.44%
12/31/2004	1211.92	1.79361	1022.77%	2284.33%	3.25%	3.40%
11/30/2004	1173.82	2.09494	987.48%	2205.92%	3.86%	4.05%
10/29/2004	1130.2	1.40869	947.06%	2116.26%	1.40%	1.53%
9/30/2004	1114.58	1.61169	932.59%	2082.90%	0.94%	1.08%
8/31/2004	1104.24	1.89309	923.01%	2059.52%	0.23%	0.40%
7/30/2004	1101.72	1.36535	920.68%	2050.84%	-3.43%	-3.31%
6/30/2004	1140.84	1.62533	956.92%	2124.47%	1.80%	1.95%
5/31/2004	1120.68	1.77578	938.24%	2082.03%	1.21%	1.37%
4/30/2004	1107.31	1.25378	925.86%	2052.52%	-1.68%	-1.57%
3/31/2004	1126.21	1.45728	943.37%	2086.84%	-1.64%	-1.51%
2/27/2004	1144.94	1.90121	960.72%	2120.34%	1.22%	1.39%
1/30/2004	1131.13	1.19547	947.93%	2089.92%	1.73%	1.84%
12/31/2003	1111.92	1.7225	930.13%	2050.45%	5.08%	5.24%
11/28/2003	1058.2	1.72748	880.36%	1943.31%	0.71%	0.88%
10/31/2003	1050.71	1.53658	873.42%	1925.52%	5.50%	5.65%

9/30/2003	995.97	1.36028	822.71%	1817.15%	-1.19%	-1.06%
8/29/2003	1008.01	1.56905	833.86%	1837.73%	1.79%	1.95%
7/31/2003	990.31	1.3436	817.46%	1800.68%	1.62%	1.76%
6/30/2003	974.5	1.39513	802.82%	1767.81%	1.13%	1.27%
5/30/2003	963.59	1.58925	792.71%	1744.30%	5.09%	5.27%
4/30/2003	916.92	1.07376	749.47%	1652.00%	8.10%	8.24%
3/31/2003	848.18	1.10564	685.79%	1518.70%	0.84%	0.97%
2/28/2003	841.15	1.69239	679.28%	1503.15%	-1.70%	-1.50%
1/31/2003	855.7	1.11632	692.76%	1527.57%	-2.74%	-2.62%
12/31/2002	879.82	1.50352	715.10%	1571.36%	-6.03%	-5.88%
11/29/2002	936.31	1.53438	767.44%	1675.68%	5.71%	5.89%
10/31/2002	885.76	1.20962	720.60%	1576.98%	8.64%	8.80%
9/30/2002	815.28	1.32084	655.31%	1441.31%	-11.00%	-10.87%
8/30/2002	916.07	1.50333	748.68%	1629.25%	0.49%	0.65%
7/31/2002	911.62	1.06451	744.56%	1618.01%	-7.90%	-7.79%
6/28/2002	989.81	1.43266	817.00%	1763.24%	-7.25%	-7.12%
5/31/2002	1067.14	1.87374	888.64%	1905.97%	-0.91%	-0.74%
4/30/2002	1076.92	0.92048	897.70%	1920.85%	-6.14%	-6.06%
3/29/2002	1147.39	0.96795	962.99%	2051.32%	3.67%	3.76%
2/28/2002	1106.73	1.65464	925.32%	1973.34%	-2.08%	-1.93%
1/31/2002	1130.21	1.13538	947.07%	2014.16%	-1.56%	-1.46%
12/31/2001	1148.08	1.35695	963.63%	2045.45%	0.76%	0.88%
11/30/2001	1139.45	1.61172	955.63%	2026.82%	7.52%	7.67%
10/31/2001	1059.78	1.00508	881.82%	1875.28%	1.81%	1.91%
9/28/2001	1040.94	0.78944	864.37%	1838.35%	-8.17%	-8.08%
8/31/2001	1133.58	1.90426	950.20%	2008.66%	-6.41%	-6.26%
7/31/2001	1211.23	1.12011	1022.13%	2149.47%	-1.08%	-0.99%
6/29/2001	1224.42	0.8377	1034.35%	2171.86%	-2.50%	-2.43%
5/31/2001	1255.82	2.02103	1063.44%	2228.55%	0.51%	0.67%
4/30/2001	1249.46	0.9582	1057.55%	2213.05%	7.68%	7.77%
3/30/2001	1160.33	1.10365	974.98%	2046.28%	-6.42%	-6.34%
2/28/2001	1239.94	1.58377	1048.73%	2191.44%	-9.23%	-9.12%
1/31/2001	1366.01	1.08359	1165.53%	2421.37%	3.46%	3.55%
12/29/2000	1320.28	1.11204	1123.16%	2334.98%	0.41%	0.49%
11/30/2000	1314.95	1.84522	1118.22%	2323.13%	-8.01%	-7.88%
10/31/2000	1429.4	1.01004	1224.25%	2530.51%	-0.49%	-0.42%
9/29/2000	1436.51	1.06324	1230.84%	2541.69%	-5.35%	-5.28%
8/31/2000	1517.68	1.97557	1306.04%	2688.94%	6.07%	6.21%
7/31/2000	1430.83	1.13999	1225.58%	2525.83%	-1.63%	-1.56%
6/30/2000	1454.6	1.02741	1247.60%	2567.37%	2.39%	2.47%
5/31/2000	1420.6	2.00675	1216.10%	2503.20%	-2.19%	-2.05%
4/28/2000	1452.43	1.07114	1245.59%	2557.74%	-3.08%	-3.01%
3/31/2000	1498.58	1.43147	1288.35%	2640.20%	9.67%	9.78%
2/29/2000	1366.42	1.65901	1165.91%	2396.01%	-2.01%	-1.89%
1/31/2000	1394.46	0.98001	1191.88%	2444.19%	-5.09%	-5.02%
12/31/1999	1469.25	1.39465	1261.17%	2578.78%	5.78%	5.89%
11/30/1999	1388.91	1.71845	1186.74%	2429.82%	1.91%	2.03%
10/29/1999	1362.93	0.90695	1162.67%	2379.43%	6.25%	6.33%
9/30/1999	1282.71	1.54463	1088.36%	2231.88%	-2.86%	-2.74%
8/31/1999	1320.41	1.74817	1123.28%	2297.61%	-0.63%	-0.49%
7/30/1999	1328.72	1.15577	1130.98%	2309.50%	-3.20%	-3.12%
6/30/1999	1372.71	1.32058	1171.73%	2387.19%	5.44%	5.55%
5/31/1999	1301.84	1.85175	1106.08%	2256.42%	-2.50%	-2.36%
4/30/1999	1335.18	0.99365	1136.97%	2313.41%	3.79%	3.87%
3/31/1999	1286.37	1.4898	1091.75%	2223.45%	3.88%	4.00%
2/26/1999	1238.33	1.53665	1047.24%	2134.07%	-3.23%	-3.11%
1/29/1999	1279.64	0.9729	1085.51%	2205.75%	4.10%	4.18%
12/31/1998	1229.23	1.38571	1038.81%	2113.20%	5.64%	5.76%
11/30/1998	1163.63	1.59846	978.03%	1992.66%	5.91%	6.06%
10/30/1998	1098.67	0.98032	917.85%	1873.08%	8.03%	8.13%
9/30/1998	1017.01	1.60072	842.20%	1724.68%	6.24%	6.41%
8/31/1998	957.28	1.52464	786.86%	1614.82%	-14.58%	-14.46%

7/31/1998	1120.67	1.11406	938.23%	1904.66%	-1.16%	-1.07%
6/30/1998	1133.84	1.24616	950.44%	1926.26%	3.94%	4.06%
5/29/1998	1090.82	1.81223	910.58%	1847.18%	-1.88%	-1.72%
4/30/1998	1111.75	1.05286	929.97%	1881.30%	0.91%	1.00%
3/31/1998	1101.75	1.27402	920.71%	1861.61%	4.99%	5.12%
2/27/1998	1049.34	1.60004	872.15%	1766.06%	7.04%	7.21%
1/30/1998	980.28	0.86215	808.17%	1640.53%	1.02%	1.11%
12/31/1997	970.43	1.34527	799.05%	1621.51%	1.57%	1.72%
11/28/1997	955.4	1.53092	785.12%	1592.48%	4.46%	4.63%
10/31/1997	914.62	1.04977	747.34%	1517.59%	-3.45%	-3.34%
9/30/1997	947.28	1.42149	777.60%	1573.49%	5.32%	5.48%
8/29/1997	899.47	1.37038	733.31%	1486.60%	-5.74%	-5.61%
7/31/1997	954.29	1.19788	784.09%	1580.82%	7.81%	7.95%
6/30/1997	885.14	1.12303	720.03%	1457.00%	4.35%	4.48%
5/30/1997	848.28	1.80875	685.88%	1390.24%	5.86%	6.09%
4/30/1997	801.34	0.9179	642.39%	1304.72%	5.84%	5.97%
3/31/1997	757.12	1.26953	601.43%	1225.62%	-4.26%	-4.11%
2/28/1997	790.82	1.51233	632.65%	1282.41%	0.59%	0.78%
1/31/1997	786.16	0.81991	628.33%	1271.66%	6.13%	6.25%
12/31/1996	740.74	1.26957	586.25%	1191.03%	-2.15%	-1.98%
11/29/1996	757.02	1.50885	601.33%	1217.15%	7.34%	7.56%
10/31/1996	705.27	0.97734	553.39%	1124.60%	2.61%	2.76%
9/30/1996	687.31	1.34515	536.75%	1091.75%	5.42%	5.63%
8/30/1996	651.99	1.48102	504.03%	1028.24%	1.88%	2.11%
7/31/1996	639.95	1.05162	492.88%	1004.93%	-4.57%	-4.42%
6/28/1996	670.63	1.02969	521.30%	1056.03%	0.23%	0.38%
5/31/1996	669.12	1.84727	519.90%	1051.66%	2.29%	2.57%
4/30/1996	654.17	0.81661	506.05%	1022.78%	1.34%	1.47%
3/29/1996	645.5	1.09529	498.02%	1006.50%	0.79%	0.96%
2/29/1996	640.43	1.4995	493.32%	995.96%	0.69%	0.93%
1/31/1996	636.02	0.81118	489.24%	985.90%	3.26%	3.40%
12/29/1995	615.93	1.07614	470.62%	950.22%	1.74%	1.92%
11/30/1995	605.37	1.61376	460.84%	930.42%	4.10%	4.39%
10/31/1995	581.5	0.81601	438.73%	887.11%	-0.50%	-0.36%
9/29/1995	584.41	1.17046	441.42%	890.66%	4.01%	4.22%
8/31/1995	561.88	1.56625	420.55%	850.54%	-0.03%	0.25%
7/31/1995	562.06	0.7457	420.72%	848.19%	3.18%	3.32%
6/30/1995	544.75	1.02542	404.68%	817.75%	2.13%	2.32%
5/31/1995	533.4	1.83087	394.16%	796.93%	3.63%	3.99%
4/28/1995	514.71	0.7327	376.85%	762.47%	2.80%	2.94%
3/31/1995	500.71	1.03626	363.88%	737.80%	2.73%	2.95%
2/28/1995	487.39	1.34523	351.54%	713.79%	3.61%	3.90%
1/31/1995	470.42	0.75135	335.82%	683.27%	2.43%	2.59%
12/30/1994	459.27	1.11396	325.49%	663.47%	1.23%	1.48%
11/30/1994	453.69	1.48114	320.32%	652.35%	-3.95%	-3.64%
10/31/1994	472.35	0.72087	337.60%	680.78%	2.09%	2.25%
9/30/1994	462.69	1.17069	328.66%	663.63%	-2.69%	-2.45%
8/31/1994	475.49	1.51487	340.51%	682.79%	3.76%	4.10%
7/29/1994	458.26	0.57327	324.55%	651.96%	3.15%	3.28%
6/30/1994	444.27	1.06793	311.59%	628.07%	-2.68%	-2.45%
5/31/1994	456.5	1.78248	322.92%	646.35%	1.24%	1.64%
4/29/1994	450.91	0.57033	317.74%	634.30%	1.15%	1.28%
3/31/1994	445.77	1.05033	312.98%	625.01%	-4.57%	-4.36%
2/28/1994	467.14	1.40932	332.78%	658.04%	-3.00%	-2.71%
1/31/1994	481.61	0.68573	346.18%	679.19%	3.25%	3.40%
12/31/1993	466.45	0.91213	332.14%	653.57%	1.01%	1.21%
11/30/1993	461.79	1.57952	327.82%	644.58%	-1.29%	-0.95%
10/29/1993	467.83	0.5871	333.42%	651.75%	1.94%	2.07%
9/30/1993	458.93	1.05713	325.17%	636.52%	-1.00%	-0.77%
8/31/1993	463.56	1.52765	329.46%	642.24%	3.44%	3.79%
7/30/1993	448.13	0.58794	315.17%	615.12%	-0.53%	-0.40%
6/30/1993	450.53	0.96592	317.39%	618.00%	0.08%	0.29%

5/31/1993	450.19	1.73462	317.07%	615.92%	2.27%	2.67%
4/30/1993	440.19	0.56216	307.81%	597.28%	-2.54%	-2.42%
3/31/1993	451.67	1.06448	318.45%	614.56%	1.87%	2.11%
2/26/1993	443.38	1.37486	310.77%	599.78%	1.05%	1.36%
1/29/1993	438.78	0.56896	306.50%	590.38%	0.70%	0.84%
12/31/1992	435.71	0.92493	303.66%	584.65%	1.01%	1.23%
11/30/1992	431.35	1.54387	299.62%	576.36%	3.03%	3.40%
10/30/1992	418.68	0.55247	287.88%	554.10%	0.21%	0.35%
9/30/1992	417.8	1.09846	287.07%	551.85%	0.91%	1.18%
8/31/1992	414.03	1.51092	283.57%	544.28%	-2.40%	-2.05%
7/31/1992	424.21	0.58973	293.01%	557.74%	3.94%	4.09%
6/30/1992	408.14	1.03347	278.12%	531.93%	-1.74%	-1.49%
5/29/1992	415.35	1.65991	284.80%	541.47%	0.10%	0.50%
4/30/1992	414.95	0.5774	284.43%	538.29%	2.79%	2.94%
3/31/1992	403.69	0.9906	274.00%	520.09%	-2.18%	-1.95%
2/28/1992	412.7	1.37703	282.34%	532.39%	0.96%	1.29%
1/31/1992	408.79	0.53825	278.72%	524.31%	-1.99%	-1.86%
12/31/1991	417.09	0.95213	286.41%	536.17%	11.16%	11.43%
11/29/1991	375.22	1.45141	247.62%	470.91%	-4.39%	-4.03%
10/31/1991	392.46	0.59871	263.59%	494.90%	1.19%	1.34%
9/30/1991	387.86	0.95019	259.33%	487.02%	-1.91%	-1.67%
8/30/1991	395.43	1.49549	266.34%	497.01%	1.96%	2.36%
7/31/1991	387.81	0.62644	259.28%	483.26%	4.49%	4.66%
6/28/1991	371.16	0.8203	243.86%	457.30%	-4.79%	-4.58%
5/31/1991	389.83	1.65574	261.15%	484.06%	3.86%	4.31%
4/30/1991	375.35	0.73954	247.74%	459.91%	0.03%	0.23%
3/29/1991	375.22	0.73898	247.62%	458.62%	2.22%	2.42%
2/28/1991	367.07	1.39651	240.07%	445.40%	6.73%	7.14%
1/31/1991	343.93	0.6181	218.63%	409.04%	4.15%	4.35%
12/31/1990	330.22	0.95031	205.93%	387.82%	2.48%	2.78%
11/30/1990	322.22	1.37085	198.52%	374.62%	5.99%	6.46%
10/31/1990	304	0.74605	181.64%	345.84%	-0.67%	-0.43%
9/28/1990	306.05	0.81547	183.54%	347.76%	-5.12%	-4.87%
8/31/1990	322.56	1.41167	198.83%	370.69%	-9.43%	-9.05%
7/31/1990	356.15	0.71317	229.95%	417.51%	-0.52%	-0.32%
6/29/1990	358.02	0.76562	231.68%	419.19%	-0.89%	-0.68%
5/31/1990	361.23	1.72836	234.66%	422.73%	9.20%	9.74%
4/30/1990	330.8	0.6471	206.47%	376.33%	-2.69%	-2.50%
3/30/1990	339.94	0.7229	214.93%	388.55%	2.43%	2.65%
2/28/1990	331.89	1.40155	207.48%	375.96%	0.85%	1.28%
1/31/1990	329.08	0.60773	204.87%	369.94%	-6.88%	-6.71%
12/29/1989	353.4	0.887	227.40%	403.76%	2.14%	2.40%
11/30/1989	345.99	1.283	220.54%	391.95%	1.65%	2.04%
10/31/1989	340.36	0.693	215.32%	382.11%	-2.52%	-2.32%
9/29/1989	349.15	0.869	223.47%	393.57%	-0.65%	-0.41%
8/31/1989	351.45	1.373	225.60%	395.58%	1.55%	1.95%
7/31/1989	346.08	0.585	220.62%	386.08%	8.84%	9.03%
6/30/1989	317.98	0.736	194.59%	345.83%	-0.79%	-0.57%
5/31/1989	320.52	1.601	196.94%	348.37%	3.51%	4.05%
4/28/1989	309.64	0.524	186.86%	330.94%	5.01%	5.19%
3/31/1989	294.87	0.721	173.18%	309.67%	2.08%	2.33%
2/28/1989	288.86	1.216	167.61%	300.33%	-2.89%	-2.49%
1/31/1989	297.47	0.53	175.59%	310.56%	7.11%	7.31%
12/30/1988	277.72	0.751	157.29%	282.59%	1.47%	1.74%
11/30/1988	273.7	1.285	153.57%	276.03%	-1.89%	-1.43%
10/31/1988	278.97	0.506	158.45%	281.47%	2.60%	2.78%
9/30/1988	271.91	0.74	151.91%	271.14%	3.97%	4.26%
8/31/1988	261.52	1.278	142.28%	255.97%	-3.86%	-3.40%
7/29/1988	272.02	0.438	152.01%	268.49%	-0.54%	-0.38%
6/30/1988	273.5	0.682	153.38%	269.89%	4.33%	4.59%
5/31/1988	262.16	1.399	142.88%	253.66%	0.32%	0.86%
4/29/1988	261.33	0.423	142.11%	250.63%	0.94%	1.11%

3/31/1988	258.89	0.669	139.85%	246.79%	-3.33%	-3.09%
2/29/1988	267.82	1.179	148.12%	257.85%	4.18%	4.66%
1/29/1988	257.07	0.395	138.16%	241.91%	4.04%	4.21%
12/31/1987	247.08	0.74	128.91%	228.11%	7.29%	7.61%
11/30/1987	230.3	0.74	113.36%	204.91%	-8.53%	-8.24%
10/30/1987	251.79	0.73	133.27%	232.30%	-21.76%	-21.54%
9/30/1987	321.83	0.74	198.16%	323.50%	-2.42%	-2.19%
8/31/1987	329.8	0.75	205.54%	332.99%	3.50%	3.73%
7/31/1987	318.66	0.74	195.22%	317.42%	4.82%	5.07%
6/30/1987	304	0.75	181.64%	297.29%	4.79%	5.05%
5/29/1987	290.1	0.76	168.76%	278.19%	0.60%	0.87%
4/30/1987	288.36	0.75	167.15%	274.94%	-1.15%	-0.89%
3/31/1987	291.7	0.7	170.24%	278.30%	2.64%	2.89%
2/27/1987	284.2	0.71	163.29%	267.69%	3.69%	3.95%
1/30/1987	274.08	0.7	153.92%	253.72%	13.18%	13.47%
12/31/1986	242.17	0.69	124.36%	211.74%	-2.83%	-2.55%
11/28/1986	249.22	0.69	130.89%	219.90%	2.15%	2.43%
10/31/1986	243.98	0.68	126.03%	212.31%	5.47%	5.77%
9/30/1986	231.32	0.7	114.30%	195.28%	-8.54%	-8.27%
8/29/1986	252.93	0.7	134.33%	221.89%	7.12%	7.42%
7/31/1986	236.12	0.69	118.75%	199.67%	-5.87%	-5.59%
6/30/1986	250.84	0.69	132.39%	217.43%	1.41%	1.69%
5/30/1986	247.35	0.7	129.16%	212.15%	5.02%	5.32%
4/30/1986	235.52	0.69	118.20%	196.38%	-1.41%	-1.13%
3/31/1986	238.9	0.68	121.33%	199.76%	5.28%	5.58%
2/28/1986	226.92	0.69	110.23%	183.92%	7.15%	7.47%
1/31/1986	211.78	0.68	96.20%	164.17%	0.24%	0.56%
12/31/1985	211.28	0.67	95.74%	162.70%	4.51%	4.84%
11/29/1985	202.17	0.67	87.30%	150.58%	6.51%	6.86%
10/31/1985	189.82	0.67	75.86%	134.50%	4.25%	4.62%
9/30/1985	182.08	0.65	68.69%	124.15%	-3.47%	-3.13%
8/30/1985	188.63	0.65	74.75%	131.38%	-1.20%	-0.86%
7/31/1985	190.92	0.65	76.88%	133.39%	-0.48%	-0.15%
6/28/1985	191.85	0.67	77.74%	133.73%	1.21%	1.57%
5/31/1985	189.55	0.67	75.61%	130.12%	5.41%	5.78%
4/30/1985	179.83	0.66	66.60%	117.55%	-0.46%	-0.09%
3/29/1985	180.66	0.64	67.37%	117.76%	-0.29%	0.07%
2/28/1985	181.18	0.65	67.85%	117.61%	0.86%	1.22%
1/31/1985	179.63	0.64	66.42%	114.98%	7.41%	7.79%
12/31/1984	167.24	0.65	54.94%	99.44%	2.24%	2.63%
11/30/1984	163.58	0.65	51.55%	94.32%	-1.51%	-1.12%
10/31/1984	166.09	0.65	53.87%	96.52%	-0.01%	0.39%
9/28/1984	166.1	0.62	53.88%	95.77%	-0.35%	0.02%
8/31/1984	166.68	0.62	54.42%	95.72%	10.63%	11.04%
7/31/1984	150.66	0.62	39.58%	76.25%	-1.65%	-1.24%
6/29/1984	153.18	0.64	41.91%	78.47%	1.75%	2.17%
5/31/1984	150.55	0.64	39.48%	74.67%	-5.94%	-5.54%
4/30/1984	160.05	0.64	48.28%	84.91%	0.55%	0.95%
3/30/1984	159.18	0.6	47.47%	83.17%	1.35%	1.73%
2/29/1984	157.06	0.6	45.51%	80.05%	-3.89%	-3.52%
1/31/1984	163.41	0.6	51.39%	86.62%	-0.92%	-0.56%
12/30/1983	164.93	0.6	52.80%	87.67%	-0.88%	-0.52%
11/30/1983	166.4	0.6	54.16%	88.65%	1.74%	2.11%
10/31/1983	163.55	0.6	51.52%	84.76%	-1.52%	-1.16%
9/30/1983	166.07	0.6	53.85%	86.92%	1.02%	1.38%
8/31/1983	164.4	0.6	52.31%	84.37%	1.13%	1.50%
7/29/1983	162.56	0.59	50.60%	81.65%	-3.30%	-2.95%
6/30/1983	168.11	0.6	55.74%	87.17%	3.52%	3.89%
5/31/1983	162.39	0.6	50.45%	80.16%	-1.23%	-0.87%
4/29/1983	164.42	0.59	52.33%	81.74%	7.49%	7.88%
3/31/1983	152.96	0.57	41.71%	68.47%	3.31%	3.69%
2/28/1983	148.06	0.57	37.17%	62.46%	1.90%	2.29%

1/31/1983	145.3	0.57	34.61%	58.82%	3.31%	3.72%
12/31/1982	140.64	0.57	30.30%	53.13%	1.52%	1.93%
11/30/1982	138.54	0.57	28.35%	50.23%	3.61%	4.04%
10/29/1982	133.71	0.57	23.87%	44.40%	11.04%	11.51%
9/30/1982	120.42	0.58	11.56%	29.50%	0.76%	1.25%
8/31/1982	119.51	0.58	10.72%	27.90%	11.60%	12.14%
7/30/1982	107.09	0.57	-0.79%	14.06%	-2.30%	-1.78%
6/30/1982	109.61	0.59	1.55%	16.12%	-2.03%	-0.98%
5/31/1982	111.88	--	3.65%	17.27%	-3.92%	-3.92%
4/30/1982	116.44	0.58	7.88%	22.05%	4.00%	4.52%
3/31/1982	111.96	0.56	3.72%	16.77%	-1.02%	-0.52%
2/26/1982	113.11	0.56	4.79%	17.39%	-6.05%	-5.59%
1/29/1982	120.4	0.55	11.54%	24.34%	-1.75%	-1.31%
12/31/1981	122.55	0.56	13.54%	25.98%	-3.01%	-2.56%
11/30/1981	126.35	0.57	17.06%	29.30%	3.66%	4.13%
10/30/1981	121.89	0.56	12.92%	24.17%	4.91%	5.40%
9/30/1981	116.18	0.56	7.63%	17.81%	-5.38%	-4.93%
8/31/1981	122.79	0.57	13.76%	23.92%	-6.21%	-5.77%
7/31/1981	130.92	0.56	21.29%	31.51%	-0.22%	0.21%
6/30/1981	131.21	0.55	21.56%	31.24%	-1.04%	-0.63%
5/29/1981	132.59	0.56	22.84%	32.07%	-0.17%	0.26%
4/30/1981	132.81	0.56	23.04%	31.73%	-2.35%	-1.93%
3/31/1981	136	0.52	26.00%	34.33%	3.60%	4.00%
2/27/1981	131.27	0.53	21.61%	29.17%	1.33%	1.74%
1/30/1981	129.55	0.53	20.02%	26.96%	-4.57%	-4.18%
12/31/1980	135.76	0.52	25.77%	32.50%	-3.39%	-3.02%
11/28/1980	140.52	0.53	30.18%	36.63%	10.24%	10.65%
10/31/1980	127.47	0.53	18.09%	23.47%	1.60%	2.02%
9/30/1980	125.46	0.52	16.23%	21.02%	2.52%	2.94%
8/29/1980	122.38	0.52	13.38%	17.56%	0.58%	1.01%
7/31/1980	121.67	0.52	12.72%	16.39%	6.50%	6.96%
6/30/1980	114.24	0.52	5.84%	8.82%	2.70%	3.16%
5/30/1980	111.24	0.52	3.06%	5.48%	4.66%	5.15%
4/30/1980	106.29	0.52	-1.53%	0.32%	4.11%	4.62%
3/31/1980	102.09	0.52	-5.42%	-4.12%	-10.18%	-9.72%
2/29/1980	113.66	0.49	5.30%	6.21%	-0.44%	-0.01%
1/31/1980	114.16	0.49	5.76%	6.22%	5.76%	6.22%
12/31/1979	107.94	--	0.00%	0.00%	--	2.14%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of
James M. Coyne and Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 2515

June 4, 2024

UG 490– PUC Response to NWN Data Request 24
Page 1

Date: May 16, 2024

TO:

Eric Nelsen
Northwest Natural Gas
220 NW Second Avenue
Portland, OR 97209

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FROM: Matt Muldoon, Mgr. Accounting and Finance

OREGON PUBLIC UTILITY COMMISSION
Docket No. UG 490 – NWN Data Request No 24.

Data Request No 24:
Please refer to Staff/100, Muldoon/41-42.
a. Referring to Muldoon/41 at lines 21-23, please explain whether Staff is referring to a historical arithmetic or geometric average market risk premium in this reference.
b. Referring to Muldoon/42 lines 4-7, please explain why Staff has relied on Morningstar's 2015 Classic Yearbook, and why it is reasonable to exclude return data for the last 9 years (i.e., 2015-2023).

Staff Response No 24:

Re: Staff/100, Muldoon/41-42, Muldoon/41 at lines 21-23, Muldoon/42 lines 4-7

a. The appropriate long-run calculation in this context is the geometric market risk premium. However, the Company makes reference to Morningstar's / Ibbotson yearbooks in this DR and so should be careful to refer back to specific elements within yearbooks to capture correctly any arithmetic references, which depending on context can use Morningstar publication defaults.

b. The 2015 Classic Yearbook is a common benchmark. This is regularly used because of the sale of the Ibbotson Yearbooks to Morningstar and the increase in price after acquisition caused many libraries to discontinue bringing new editions into their collection. Where practicable, Staff tries to use reference material that is generally available to intervenors such as at the Portland, OR Public Library or Oregon Library. That is consistent with Oregon government's goals of transparency and access.

   The other issue is that Morningstar may not necessarily have the same approach to independent unbiased analysis that characterizes the goals of Roger Ibbotson in his time as a University of Chicago professor. For example, the Wall Street Journal has been critical of Morningstar and its assessment and indications of relative risk. For a discussion of this concern regarding the "sell side" tendencies of Morningstar, see "The Morningstar Mirage" by Kirsten Grind, Tom McGinty and Sarah Krouse published in the Wall Street Journal. Oct 25, 2017.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of
James M. Coyne and Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 2516

June 4, 2024

NW NATURAL DATA REQUEST 7 TO AWEC:

Please refer to AWEC/100, at Mullins/9:

a. Referring to lines 1-3, Please provide all studies, documentation, and analysis that Mr. Mullins has performed that supports his position that Beta calculations for "other stocks" based on monthly returns are "not necessarily" lower than Beta calculations for "other stocks" using weekly returns.

b. Referring to lines 7-11, please quantify how much weight Mr. Mullins gave to his CAPM estimates using Yahoo Finance Beta coefficients.

AWEC RESPONSE:

a. AWEC objects to this request on the basis that it does not accurately characterize Mr. Mullins testimony. Mr. Mullins never stated that the "that Beta calculations for 'other stocks' based on monthly returns are "not necessarily" lower than Beta calculations for "other stocks" using weekly returns. AWEC also objects to this request on the basis that it overly vague. Notwithstanding said objections, AWEC responds as follows:

The referenced testimony was pointing out that there are a variety of ways that a beta can be calculated and that the Yahoo method, which uses monthly returns, resulted in materially lower betas for the gas proxy group than did the Value Line and Bloomberg calculations. The Yahoo method, however, does not uniformly result in lower betas for all securities. Consider the following securities:

	Beta	
Security	Value Line	Yahoo
AAPL	1.000	1.260
CAT	1.100	1.180
GS	1.300	1.390
HD	1.000	1.010
INTC	0.900	1.090
MMM	1.000	1.040
NKE	1.080	1.200
CRM	0.900	1.300
DIS	1.100	1.390
DOW	1.100	1.290

These securities had a higher Yahoo beta as compared to Value Line, although there are many other securities, such as the gas proxy group, where the opposite is true. Therefore, Mr. Mullins testimony was simply stating that there may be some characteristic of gas stocks that causes them to be less risky based on monthly beta, as opposed to a weekly beta. This commentary, however, is not consequential to Mr. Mullins analysis, as he applied zero practical weight to the yahoo betas.

b. While Mr. Mullins did not apply specific weighting percentages in deriving his recommendation, the Yahoo finance betas were not used to inform his recommendation. As he noted on Page 9, lines 7-8, he was not able to verify the accuracy of the Yahoo Finance beta calculations.

Response Date: May 10, 2024
Witness(es) Most Knowledgeable About Response: Bradley Mullins

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Reply Testimony of Daniel B. Kizer

DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS EXHIBIT 2600

June 4, 2024

EXHIBIT 2600 – REPLY TESTIMONY – DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS

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I. INTRODUCTION AND SUMMARY

Q. Are you the same Daniel B. Kizer who filed Direct Testimony in this proceeding on behalf of Northwest Natural Gas Company dba NW Natural ("NW Natural" or the "Company")?

A. Yes, I presented NW Natural/500, Kizer.

Q. What is the purpose of your Reply Testimony in this proceeding?

A. The purpose of my Reply Testimony is to respond to testimony filed on April 18, 2024, by Public Utility Commission of Oregon Staff ("Staff") and Alliance of Western Energy Consumers ("AWEC") related to the Company's major transmission and distribution system projects, storage facility projects and safety-driven system projects. I will respond to issues presented in the Opening Testimony of Staff witnesses David Abraham (Staff/500, Abraham), Laurel Anderson (Staff/600, Anderson and Staff/2300, Anderson), and Kevin Hennessy (Staff/2100, Hennessy), and AWEC witness Brad Mullins (AWEC/100, Mullins).

Q. Please summarize your Reply Testimony.

A. *First*, I respond to Staff's Opening Testimony addressing Ms. Anderson's Issue 6 (Attestations and Proposed Project Adjustments). As part of my response, I provide an update of the distribution system projects included for recovery in this case, including those projects that Ms. Anderson recommends be the subject of an officer attestation or be removed from rate base.

Second, I respond to Staff's Opening Testimony addressing Mr. Abraham's Issue 3 (New Plant – Major Storage Projects). As part of my response, I provide an update of the storage facility projects included for recovery in this case.

Third, I respond to Staff's Opening Testimony addressing Mr. Hennessy's Issue 1 (NW Natural Safety and Inspection Programs). As part of my response, I provide an update of the safety-related projects and programs included for recovery in this case.

Fourth, I respond to AWEC's Opening Testimony addressing Mr. Mullins's recommended attestation process.

II. RESPONSE TO STAFF WITNESS MS. ANDERSON

Q. Which distribution system projects specifically discussed in your Direct Testimony does Staff recommend be the subject of an officer attestation?

A. Staff recommends an officer attestation for the following distribution system projects specifically discussed in my Direct Testimony:[1]

- North Coast Feeder Uprate Project – Section A
- Public Works Project – Tualatin-Sherwood Road Grading Project
- P30 Willis Creek Horizontal Directional Drilling ("HDD") Install Project
- SE Gate Station Rebuild Project

[1] Staff/600, Anderson/18-19.

Q. Why does Staff recommend that the above-listed distribution system projects be the subject of an officer attestation?

A. Staff recommends officer attestations for several stated reasons. For the North Coast Feeder Uprate Project – Section A, Staff notes that this project is expected to be placed in service "just prior to the rate effective date of October 31, 2024."[2] I will address Staff's position regarding North Coast Feeder Uprate Project – Section B later in my Reply Testimony. Staff comments that the Tualatin-Sherwood Road Grading Project was completed in October 2022, so "[a]ctual costs to place the project in service should be available to replace estimates."[3] The P30 Willis Creek HDD Install Project is in the planning stage and scheduled for construction in Summer 2024, so Staff believes that there is "a risk that the project will not be in service prior to the rate effective date, and the estimated cost is a rough order of magnitude estimate."[4] Finally, the SE Gate Station Rebuild Project is expected to be placed in service "just prior to the rate effective date," so Staff has the same concerns as it expressed about the P30 Willis Creek HDD Install Project.[5]

[2] Staff/600, Anderson/18.

[3] Staff/600, Anderson/18.

[4] Staff/600, Anderson/18-19.

[5] Staff/600, Anderson/19.

Q. Please provide an update of the above-listed distribution system projects that Staff recommends be the subject of an officer attestation.

A. The following is an update of the above-listed distribution system projects, in light of Staff's stated concerns and its recommendation that they be the subject of an officer attestation.

- **North Coast Feeder Uprate Project – Section A.** The scope and timing of this project have not changed. The total expected cost of the project has increased to approximately $9.1 million from approximately $8.2 million to reflect more refined cost data as the project lifecycle has progressed.
- **Tualatin-Sherwood Road Grading Project.** The final actual cost to place the project in service is approximately $8.6 million.
- **P30 Willis Creek HDD Install Project.** This project is in the bidding phase, with construction expected to start early July 2024 and the project expected to be in service by the end of September 2024. The total cost to complete the P30 Willis Creek HDD Install Project has not changed from the approximately $3.5 million identified at NW Natural/500, Kizer/12.
- **SE Gate Station Rebuild Project.** The scope and timing of this project have not changed. The total expected cost of the project has increased to approximately $4.4 million from approximately $2.3 million to reflect final vendor pricing for the new check meter, line heater, coalescing filter and separator, additional piping modifications needed to ensure the station can be

kept online during the entire rebuild construction phase, and the replacement of transmission piping that lacked adequate documentation.

Q. Turning now to North Coast Feeder Uprate Project – Section B, what is Staff's recommendation?

A. For the North Coast Feeder Uprate Project – Section B, Staff recommended that this phase "be removed from revenue requirements and rate base for this general rate case" because "this phase of the project will not be 'used and Useful' prior to the prior to the [sic] rate effective date."[6]

Q. Did you agree with Staff witness Anderson that the Company should remove North Coast Feeder Uprate Project – Section B from revenue requirements and rate base for this general rate case?

A. No. My Direct Testimony noted that Section B of the North Coast Feeder Uprate Project is expected to be completed in December 2025, after the end of the Test Year, at an expected total cost of approximately $6.4 million[7] to transparently inform the Commission and relevant stakeholders regarding the Company's mission critical efforts and investment. The Company did not include the expected cost of Section B of the North Coast Feeder Uprate Project in its revenue requirements or rate base for this general rate case.

[6] Staff/600, Anderson/18; *see also* Staff/600, Anderson/4-5, 7.

[7] NW Natural/500, Kizer/8.

Q. Did Staff witness Anderson subsequently acknowledge that the Company did not include the expected cost of Section B of the North Coast Feeder Uprate Project in its revenue requirements or rate base for this general rate case?

A. Yes. On May 17, 2024, Staff filed Exhibit 2300, Supplemental Corrected Testimony of Laurel Anderson. In the Supplemental Corrected Testimony, Staff witness Anderson stated that she had "been informed that NW Natural did not include costs for Section B of the North Coast Feeder [Uprate] Project in its rate case proposal."[8] Ms. Anderson concluded, therefore, that Staff's $6.4 million downward "adjustment" of capital investment "was not necessary."[9]

Q. Do you agree that Staff's $6.4 million downward "adjustment" of capital investment "was not necessary"?

A. Yes, for the reasons I stated earlier.

III. RESPONSE TO STAFF WITNESS MR. ABRAHAM

Q. What is Staff's position regarding the Company's major storage facility projects in this general rate case?

A. After summarizing the Company's major storage facility projects in this general rate case, Staff recommended "no proposed adjustments for gas storage projects included in this rate case at this time."[10]

[8] Staff/2300, Anderson/6-7.

[9] Staff/2300, Anderson/7.

[10] Staff/500, Abraham/14.

Q. Can you please provide an update of the Company's major storage facility projects in this general rate case?

A. Yes. I first will provide an update of projects at the Mist Storage Facility, specifically the Mist GC500 and GC600 Turbine Compressor Cold Spare Projects, Electrical Upgrades Project (Phase 2), Mist Upgrade Methanol Injection at Injection/Withdrawal ("I/W") Wells Project and Mist Instruments & Controls Project (Phase 3). I then will provide an update of projects at the Company's Portland Liquefied Natural Gas ("LNG") storage facility ("PLNG"), specifically the PLNG Valve and Controls Replacement Project, the PLNG Boil-Off Compressor Project and the PLNG Pretreatment Improvements Project. Finally, I will provide an update of a Newport LNG storage facility ("NLNG") project, specifically the T-1 Tank Improvements Project.

Q. Please provide an update of the Mist GC500 and GC600 Turbine Compressor Cold Spare Projects.

A. The total cost estimate of the Mist GC500 Turbine Compressor Cold Spare Project remains at approximately $4.1 million, or approximately $3.7 million on an Oregon-allocated basis, and the expected October 2024 in-service timing remains the same as presented in my Direct Testimony.[11] The Company has purchased the gas generator and power turbine rotor. The gas generator has been received and the power turbine rotor will be delivered by October 2024. Since my Direct Testimony, the Company has determined that it does not need to purchase the

[11] NW Natural/500, Kizer/23-24.

spare exhaust collector as a result of refined scoping during the project lifecycle progression.

Turning to the Mist GC600 Turbine Compressor Cold Spare Project, its expected in-service time has shifted from January 2024 to October 2024 and its estimated total cost has increased incrementally from approximately $1.2 million for core utility service, which is approximately $1.1 million on an Oregon-allocated basis, to approximately $1.6 million for core utility service, which is approximately $1.4 million on an Oregon-allocated basis. The expected in-service time has shifted and the estimated total cost has increased because Siemens Energy, the original equipment manufacturer (OEM), determined that it needed to replace additional parts of the power turbine assembly after it arrived at the Maintenance Repair and Overhaul Center (MROC) in Houston, Texas for disassembly, cleaning and inspection, and to purchase additional miscellaneous spares such as new and rebuilt fuel control valves, bleed controllers, vane cases, and vibration probes.

The Mist GC500 and GC600 Turbine Compressor Cold Spare Projects, and a longer-term solution to address the underlying problems with the GC500 and GC600 units, are addressed in the Reply Testimony of Zachary D. Kravitz (NW Natural/2200, Kravitz).

Q. Please provide an update of the Mist Electrical Upgrades Project (Phase 2).

A. The scope and estimated total cost of the Mist Electrical Upgrades Project (Phase 2) remains the same as presented in my Direct Testimony.[12] The expected in-

[12] NW Natural/500, Kizer/28-30.

service timing of the project has moved up a few months to August 2024 from October 2024.[13]

Q. Please provide an update of the Mist Upgrade Methanol Injection at I/W Wells Project.

A. The expected August 2024 in-service timing remains the same as presented in my Direct Testimony.[14] The scope of the Mist Upgrade Methanol Injection at I/W Wells Project has expanded, as follows. In January 2024, the Company added extra pumps operating in parallel at four high-volume I/W wells. A singular pump did not provide the required injection rates, and the next-sized pump would have been too large. The Company determined that a dual parallel pump option was the best value option due to cost, standardization of parts, and ergonomics.

Also in January 2024, the Company identified the need to install an additional 15 feet of buried power gas piping at each of the methanol injection sites (13 sites) with poly pipe sleeves. This additional work included the removal of spoils associated with each site excavation and additional O-let fittings installed at each location for the new power gas feed. The work also ensured that the supply of power gas would not stop if hydrates were to form in the power gas feed pipe. Further, relocating the power gas feed to be downstream of the methanol injection and buried will significantly reduce the chances of hydrates forming in the power gas feed supply pipe.

[13] NW Natural/500, Kizer/29.

[14] NW Natural/500, Kizer/32.

Other additional work included the replacement of the junction boxes on the methanol injection shed at seven sites, additional methanol disposal, and the installation of concrete pads.

As a result of this expanded scope, the Company's most recent cost estimate for this project has increased incrementally from $4.6 million for core utility service, which is approximately $4.1 million on an Oregon-allocated basis, to approximately $5.4 million for core utility service, which is approximately $4.8 million on an Oregon-allocated basis.

Q. Please provide an update of the Mist Instrument & Controls Project (Phase 3).

A. The scope, estimated total cost and expected October 2024 in-service timing remain the same as presented in my Direct Testimony.[15]

Q. Please provide an update of the PLNG Valve and Controls Replacement Project.

A. The scope of the PLNG Valve and Controls Replacement Project remains the same as presented in my Direct Testimony,[16] and the Company accelerated the January 2024 in-service timing of the project to ensure that the Portland LNG storage facility was available to serve our customers on the Company's record daily send out of January 13, 2024, and during the entire severe winter weather event from January 13-19, 2024.[17] The accelerated timeframe slightly increased

[15] NW Natural/500, Kizer/32-33.

[16] NW Natural/500, Kizer/33-34.

[17] NW Natural/2200, Kravitz.

the cost of the PLNG Valve and Controls Replacement Project from approximately $4.3 million, or approximately $3.8 million on an Oregon-allocated basis, to approximately $4.5 million, or approximately $4.0 million on an Oregon-allocated basis.

Q. Please provide an update of the PLNG Boil-Off Compressor Project.

A. The scope of the PLNG Boil-Off Compressor Project remains the same as presented in my Direct Testimony,[18] and the expected in-service timing of the project has moved up a few months to August 2024 from October 2024.[19] The Company's most recent cost estimate for the Portland LNG Boil-Off Compressor Project has increased incrementally from $4.8 million, or approximately $4.2 million on an Oregon-allocated basis, to approximately $6.4 million, or approximately $5.7 million on an Oregon-allocated basis, to reflect higher structural and mechanical installation costs than estimated prior to the bidding phase, and subsurface explorations resulting in higher than anticipated structural engineering and foundation costs.

Q. Please provide an update of the PLNG Pretreatment Improvements Project.

A. The scope and expected October 2024 in-service timing of the PLNG Pretreatment Improvements Project remain the same as presented in my Direct Testimony.[20] The Company's most recent cost estimate for the Portland LNG Pretreatment Improvements Project has increased slightly from approximately $2.6 million, or

[18] NW Natural/500, Kizer/35.

[19] NW Natural/500, Kizer/35.

[20] NW Natural/500, Kizer/37-39.

approximately $2.3 million on an Oregon-allocated basis, to approximately $2.7 million, or approximately $2.4 million on an Oregon-allocated basis, to reflect more refined cost data as the project lifecycle has progressed.

Q. Please provide an update of the NLNG T-1 Tank Improvements Project.

A. The scope and expected October 2024 in-service timing of the NLNG T-1 Tank Improvements Project remain the same as presented in my Direct Testimony.[21] The Company's most recent cost estimate for the Newport LNG T-1 Tank Improvements Project has increased a bit from approximately $3.5 million, or approximately $3.2 million on an Oregon-allocated basis, to approximately $3.9 million, or approximately $3.5 million on an Oregon-allocated basis, to reflect higher contractor pricing than was forecast at the time of my Direct Testimony.

IV. RESPONSE TO STAFF WITNESS MR. HENNESSY

Q. What is Staff's position regarding the safety-related projects that the Company is performing on its transmission and distribution systems and at its storage facilities?

A. After indicating that it has reviewed the Company's investments being made for safety-related programs, Staff states that it does "[n]ot generally" have any concerns regarding the approach being taken with these programs.[22] Staff does indicate that "certain programs warrant further mention"[23] and that Staff's

[21] NW Natural/500, Kizer/39-41.

[22] Staff/2100, Hennessy/2.

[23] Staff/2100, Hennessy/2.

recommendations and issues "may change when informed by new data and after reviewing testimony and analysis by other parties."[24]

Q. As Staff's recommendations and issues "may change" after its Opening Testimony, can you please provide an update of the Company's safety-related projects in this general rate case?

A. Yes. I first will provide an update of the Company's In-Line Inspection ("ILI") Conversion Projects for 2024, specifically S36 Mid-Willamette Valley Feeder ILI Project, S24 Granger Trans ILI Project, and S22 Albany Trans ILI Project. I then will provide an update of the Company's Underground Storage Facilities – Well Integrity Program, Seismic Projects, Proactive Excess Flow Valve ("EFV") Installation Program, and Probabilistic Distribution Risk Model Project.[25]

Q. Please provide an update of the S36 Mid-Willamette Valley Feeder ILI Project.

A. The scope of the S36 Mid-Willamette Valley Feeder ILI Project remains the same as presented in my Direct Testimony,[26] and the expected in-service timing of the project has moved up a few months to June 2024 from October 2024.[27] The Company's most recent total cost estimate for the S36 Mid-Willamette Valley Feeder ILI Project has increased slightly from approximately $2.1 million to approximately $2.2 million, to reflect more refined cost data as the project lifecycle has progressed.

[24] Staff/2100, Hennessy/1.

[25] NW Natural/500, Kizer/41-53.

[26] NW Natural/500, Kizer/46.

[27] NW Natural/500, Kizer/46.

Q. Please provide an update of the S24 Granger Trans ILI Project.

A. The expected October 2024 in-service timing of this project remains the same as presented in my Direct Testimony.[28] The project's estimated total cost has increased, from approximately $2.2 million to approximately $3.0 million, to reflect higher than expected costs of performing a field investigation of potential unpiggable fittings on this pipeline and addressing jurisdictional permit work conditions such as the need to perform work at night.

Q. Please provide an update of the S22 Albany Trans ILI Project.

A. The scope and expected total cost estimate for the S22 Albany Trans ILI Project remain the same as I presented in my Direct Testimony.[29] The expected in-service timing of the project has moved up a few months to July 2024 from October 2024.

Q. Please provide an update of the Company's Underground Storage Facilities – Well Integrity Program.

A. The scope, estimated total cost and expected June 2024 in-service timing of this project remain the same as presented in my Direct Testimony.[30]

Q. Please provide an update of the Company's Seismic Projects.

A. The Company completed its risk analysis in March 2024 and is currently reviewing it for future implementation.

[28] NW Natural/500, Kizer/46.

[29] NW Natural/500, Kizer/46.

[30] NW Natural/500, Kizer/48.

Q. Please provide an update of the Company's Proactive EFV Installation Program.

A. To date, the Company has installed more than 304,000 EFVs on residential and commercial services (up from the 296,000 amount provided in my Direct Testimony[31]).

Q. Please provide an update of the Company's Probabilistic Distribution Risk Model Project.

A. NW Natural last month successfully kicked off this project with the risk model vendor and will be coordinating with the vendor throughout 2024 to gather distribution system data to develop the model.

Q. Earlier, you mentioned that Staff indicates that "certain programs warrant further mention."[32] To which Company programs is Staff referring?

A. Staff provides comments and recommendations regarding the Company's ILI Conversion Projects, the Underground Storage Facilities – Well Integrity Program and Non-Hazardous Leakage Projects.[33]

Q. What is Staff's comment with the Company's ILI Conversion Projects, and what is Staff's recommendation related to that comment?

A. Staff is "concerned" that the Company incurred significant costs for the P31/P75 McMinnville Trans ILI Project after it went into service. In response, Staff recommends that the Commission require the Company to "keep additional

[31] NW Natural/500, Kizer/50.

[32] Staff/2100, Hennessy/2.

[33] Staff/2100, Hennessy/2-4.

records and perform research in advance of construction to mitigate such construction overruns or surprises."[34]

Q. How do you respond to Staff's concern and recommendation regarding the Company's ILI Conversion Projects?

A. The Company agrees with Staff that it is good practice to document lessons learned from the P31/P75 McMinnville Trans ILI Project. For that project, one of the lessons learned was that our legacy as-built drawings and mapping information do not always completely show unpiggable fittings utilized for pipe relocation projects. After the P31/P75 McMinnville Trans ILI Project, the Company has expanded the pre-construction review process by field investigating (i.e., potholing) locations where pipeline records indicate that pipeline replacement has occurred. For example, if a particular pipeline was replaced during our cast-iron and bare-steel replacement program, it is possible that the fittings installed during that process are not ILI compatible. The potential need to remediate these fittings will add potential cost to the project, which can be known earlier in the planning process for ILI projects.

Another lesson learned by the Company through the P31/P75 McMinnville Trans ILI Project relates to six-inch and smaller pipeline projects constructed by NW Natural between the mid-1990s and mid-2000s that utilized floating ball valves for main line blocking valves. The floating ball valve used on our six-inch transmission main has been found to be unpiggable. The ball of that valve is

[34] Staff/2100, Hennessy/3.

documented in as-built drawings as a fully open ball valve by the manufacturer, but because the ball is "floating" within the body of the valve it can easily become misaligned during the pigging process, causing damage to the ILI tools. This situation happened with the P31/P75 McMinnville Trans ILI Project. The valve was documented in as-built drawings as a full port ball valve that is piggable. However, that turned out to not be true after the ILI tool became damaged. The P31/P75 McMinnville Trans ILI Project was the Company's first attempt to pass an in-line inspection tool through this type of valve. For future six-inch ILI runs, as-built drawings and records will be reviewed for this era of installation and floating ball valves will be removed prior to attempting to pig the line.

Q. What is Staff's recommendation related to the Company's Underground Storage Facilities – Well Integrity Program?

A. Staff recommends that the Commission require the Company to "develop clear cost estimates 'for the life of the facility' and that the Company include these cost estimates in the Company's annual Oregon Safety Project Plan ("SPP") filed in docket UM 1900."[35]

Q. How do you respond to Staff's recommendation regarding the Company's Underground Storage Facilities – Well Integrity Program?

A. The Company's position is that it is best to continue its current practice of forecasting next year's costs and showing historical spend amounts. The Company's ten-year Underground Storage Facilities – Well Integrity Program will

[35] Staff/2100, Hennessy/3.

be used to forecast improvements, inspections, and operations and maintenance ("O&M") work for our underground storage reservoirs and wells.

The Company does not agree with Staff's recommendation that the Company develop "life of the facility" cost estimates. The Company currently provides in its SPP filings a cost estimate for safety-related work that it intends to perform in the current calendar year, and summarizes the safety-related work that was performed the previous year. Estimating the cost for the "life of the facility" would require forecasts for costs and variables that are mostly unknown and unmeasurable over the entire facility's lifecycle, including but not limited to:

- The actual useful life of the facility;
- The depreciation schedule of the facility;
- The maintenance required during the actual useful life of the facility;
- The cost to perform the well integrity compliance inspections for the life of the facility;
- The cost to make repairs to address well integrity issues discovered during any future well compliance inspections over the remaining useful life of the facility; and
- The cost to comply with any new, future regulations.

Q. What is Staff's comment with the Company's Non-Hazardous Leakage Projects, and what is Staff's recommendation related to that comment?

A. Staff's "concern" is that it is "not clear" from the Company's SPP and Initial Testimony "how many facilities have such leaks."[36] In response, Staff recommends that the Commission require the Company to "capture and provide more detail in the Safety Project Plan, showing starting or prior counts and severity of leaks, the reduction in the count and severity, the estimated methane reduction, and the costs for the year."[37]

Q. How do you respond to Staff's concern and recommendation regarding the Company's Non-Hazardous Leakage Projects?

A. I provide three points in response to Staff's recommendation. First, the Company annually submits updates to its O&M manuals, including its Distribution Integrity Management Program Plan ("DIMP Plan"). The DIMP Plan discusses the Company's leak management program in Section 8.2. In Section 9, the Company discusses performance measures, monitoring of performance and how the Company tracks the number of eliminated or repaired hazardous and non-hazardous leaks, per Code of Federal Regulations (CFR) 192.703, categorized by cause and material. Appendices D and E of the DIMP Plan contain the leakage repair data.

[36] Staff/2100, Hennessy/3-4.

[37] Staff/2100, Hennessy/4.

Second, estimating the volume of methane reduction would be problematic, as the leak flow rates and the specific length of time the leaks have occurred before repair or elimination are unknown. Gas utilities are not required to provide leakage flow rates in our Annual Gas Distribution System Report filings with the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration, where hazardous and non-hazardous leaks are reported.

Third, quantifying costs of leakage repairs would be problematic, as the Company's leakage repair costs are blended with costs for other capital and maintenance work when leaks are eliminated or repaired.

V. RESPONSE TO AWEC WITNESS MR. MULLINS

Q. Are you replying to any recommendations made by AWEC witness Mr. Mullins?

A. Yes. Mr. Mullins recommends an attestation process for projects in excess of $1 million and that the filing occur at least 15 days before the rate effective date.[38] "If any project is not in service, or has a capital cost less than NW Natural had forecast, NW Natural would be required to reduce the ultimate rate increase approved in the Commission's final order."[39] The costs of any projects not in service by October 31, 2024, would be removed from the Company's revenue requirement approved by the Commission. Mr. Mullins indicated that "NW Natural

[38] AWEC/100, Mullins/19, 21-22.

[39] AWEC/100, Mullins/22.

provided the specific funding projects included in revenue requirement in the confidential attachment provided in response to AWEC Data Request 39."[40]

Q. Do you agree with Mr. Mullins' recommendation?

A. I agree with the concept of an attestation process, but the process should be limited to attestations of the particular projects identified in Staff witness Ms. Anderson's Direct Testimony, specifically North Coast Feeder Uprate Project, Tualatin-Sherwood Road Grading Project, P30 Willis Creek HDD Install Project, and SE Gate Station Rebuild Project.[41] If the Commission were to determine that a broader attestation process is needed beyond the process recommended by Staff, then the Company would be amendable to using an attestation process for projects in excess of $1 million, as recommended by Mr. Mullins. Any required attestation process, however, should follow the two-step process that the Commission approved in the Company's last general rate case, UG 435.[42]

Q. Does this conclude your Reply Testimony?

A. Yes, it does.

[40] AWEC/100, Mullins/22.

[41] Staff/600, Anderson/18-19.

[42] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 435, Order No. 22-388, Appendix A, Stipulation, Paragraph 3 ("Attestation of Capital Projects") (Oct. 24, 2022).

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Reply Testimony of Wayne K. Pipes

FACILITIES
EXHIBIT 2700

June 4, 2024

EXHIBIT 2700 – REPLY TESTIMONY – FACILITIES

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I. INTRODUCTION AND SUMMARY

Q. Are you the same Wayne K. Pipes who filed Direct Testimony in this proceeding on behalf of Northwest Natural Gas Company dba NW Natural ("NW Natural" or the "Company")?

A. Yes, I presented NW Natural/600, Pipes.

Q. What is the purpose of your Reply Testimony in this proceeding?

A. The purpose of my Reply Testimony is to 1) provide an update on the facilities projects included in this case, 2) respond to Public Utility Commission of Oregon Staff ("Staff") concerns as stated in the Opening Testimony of Laurel Anderson, and 3) respond to Oregon Citizens' Utility Board ("CUB") concerns as stated in the Opening Testimony of John Garrett.

Q. Please summarize your Reply Testimony.

A. My testimony provides updates regarding the projects discussed in my Direct Testimony—all of which are on track to be completed within budget and by October 31, 2024. Additionally, I respond to Staff's testimony, which does not question the prudence of any project, but requests attestations based on uncertainty about the reliability of projected costs for those projects entering service near the rate-effective date. Finally, I respond to CUB's position that the Company should reconsider its plans to perform seismic resiliency and office construction projects to attempt to slow rate increases.

II. PROJECT UPDATES

Q. Are all the facilities projects previously described in your testimony on-track to be placed in service before the November 1, 2024 rate effective date?

A. Yes, each of the projects are on schedule to be completed this year before the rate effective date.

A. Central Resource Center Phase 2

Q. Please briefly summarize the Central Resource Center ("RC") Phase 2 project.

A. The Central RC construction addressed needs for the Company to have a centrally located resource center from which operations crews, including emergency response, can be dispatched. Phase 2 of this project included building a one-story office building with a warehouse attached to house workspace for emergency crews. The new buildings constructed in Phase 2 will comply with modern seismic requirements.[1]

Q. Please provide an update on the Central RC Phase 2 construction.

A. The Central RC Phase 2 construction was completed on November 15, 2023.

Q. What cost recovery is NW Natural requesting for the Central RC Phase 2 construction project?

A. NW Natural is continuing to seek to recover its capital investment of $9.2 million to complete Phase 2 of the Central RC for our Oregon customers.

[1] NW Natural/600, Pipes/6-7.

B. Sunset RC

Q. Please briefly summarize the Sunset RC project.

A. NW Natural is making seismic upgrades to the Sunset RC to address the resiliency of critical equipment and known seismic vulnerabilities and to install a new decanter system and truck scale.[2]

Q. Please provide an update on the Sunset RC project.

A. The construction at the Sunset RC began in May 2024 and is on schedule to be completed by October 31, 2024.

Q. What cost recovery is NW Natural requesting for the Sunset RC project?

A. We continue to project the Sunset RC construction will be completed within the budget of $4.1 million. NW Natural continues to seek the most cost-effective way to complete these necessary construction and upgrades while minimizing impacts on rates.

C. Miller Station Tenant Improvements

Q. Please briefly summarize the Miller Station tenant improvements.

A. The Company expanded and improved the office space at Miller Station to house more employees and retrofitted to address seismic deficiencies and other safety issues. The improvements address electrical, mechanical, and plumbing systems that were past their usable life and provide safety upgrades to the office space by installing new lighting fixtures, branch circuits, data cabling, heating and cooling

[2] NW Natural/600, Pipes/13.

systems, water supply and drain lines, sinks, toilets, and showers.[3] The construction at Miller Station will improve employee safety and the structural integrity of the building.

Q. Please provide an update on the Miller Station tenant improvements.

A. The Company completed construction on November 9, 2023.[4]

Q. What cost recovery is NW Natural requesting for the Miller Station tenant improvements?

A. The Company is continuing to seek $3.2 million for the renovations at Miller Station, or to recover $2.8 million on an Oregon-allocated basis.

D. Sherwood Data Center

Q. Please briefly summarize the upgrades NW Natural is making at the Sherwood Data Center.

A. NW Natural upgraded the electrical system, the HVAC system, and the fire alarm system at the Sherwood Data Center to improve reliability and make the Data Center less vulnerable to failure. NW Natural is also adding a remote monitoring system and performing seismic upgrades.[5]

Q. Please provide an update on the Sherwood Data Center upgrades.

A. The Company completed the Sherwood Data Center upgrades to the electrical, mechanical, and alarm system as of April 2024. The remaining Sherwood Data Center upgrades are on schedule to be completed in July 2024.

[3] NW Natural/600, Pipes/18.

[4] NW Natural/600, Pipes/23.

[5] NW Natural/600, Pipes/24.

Q. What cost recovery is NW Natural requesting for the Sherwood Data Center project?

A. The Company is continuing to seek $3 million, or to recover $2.7 million on an Oregon-allocated basis. NW Natural continues to seek the most cost-effective way to complete the necessary upgrades while minimizing impacts on rates.

E. Physical Security Upgrades

Q. Please briefly summarize the physical security upgrades the Company is performing.

A. NW Natural is undertaking a comprehensive, multi-year effort to enhance the physical security at the Company's facilities and field infrastructure in response to increasing threats and new direction from the Transportation Security Administration. The security upgrades were performed beginning with a pilot program for 2023 and expanding to additional sites in 2024. The upgrades include a combination of new fencing, anti-climb fencing, lighting, video surveillance systems, intelligent intrusion detection systems, enhanced gates, gate alarms, and/or radar stations,[6] though the exact security system installed varies depending on the evaluation of the site.

Q. Please provide an update on the security upgrades.

A. The pilot program concluded at the end of 2023, and additional upgrades are on schedule to be completed by October 31, 2024.

[6] NW Natural/600, Pipes/34.

Q. What cost recovery is NW Natural requesting for the security upgrades?

A. The pilot program cost $1.8 million in Oregon, as projected in my Direct Testimony. The additional upgrades conducted in 2024 were originally projected to be $5 million (predominantly in Oregon), and we remain within that budget.

III. Reply to Staff Opening Testimony

Q. Please summarize Staff's testimony regarding the projects discussed above.

A. Staff reviewed each of the projects described in the Company's Direct Testimony and agreed that they were necessary and that the costs are prudently incurred.[7] Staff recommended the Commission require an attestation from the Company describing the cost and in-service date for the Sunset RC specifically and for projects expected to be placed into service near the rate effective date generally.[8]

Q. Did Staff indicate the reason for recommending the Company provide an attestation?

A. Staff indicated in its testimony that it is interested in attestations because it is concerned about the reliability of the Company's cost projections.[9]

Q. How does NW Natural determine its estimates for cost projections?

A. The Company uses a robust process to reach estimates and has sought the most cost-effective ways to complete necessary construction and upgrades while minimizing impacts on rates. The final costs are provided once the project is in-service and costs are known. The process NW Natural follows to prepare and

[7] Staff/600, Anderson/17.

[8] Staff/600, Anderson/15, 17.

[9] Staff/600, Anderson/17.

update its cost estimates results in reliable amounts that become increasingly focused as the project progresses.

Q. Which projects are affected by Staff's request for an attestation?

A. Both the Sunset RC and the Company's 2024 security enhancements have a projected completion date of October 31, 2024. NW Natural is confident that these projects will be placed into service on or before this date and is willing to submit officer attestations regarding the projected completion of these projects and their forecasted final cost.

Q. Did Staff have any other recommendations regarding the projects you discussed above and in your Direct Testimony?

A. No.

IV. Reply to CUB Opening Testimony

Q. Please describe CUB's Opening Testimony regarding the projects discussed in your Direct Testimony.

A. CUB does not specifically question the prudence or cost of any of the Company's ongoing projects, nor does CUB make any recommendations regarding the projects currently underway.

Q. Does CUB nevertheless raise general concerns regarding facilities projects?

A. Yes, CUB testifies that it is "evaluating" and will discuss in future testimony whether the Company is "appropriately prioritizing investments in accordance with their importance and immediate need."[10] CUB mentions "earthquake contingency

[10] CUB/200, Garrett/1.

planning" and "office construction" as potential areas of "overspend."[11] CUB states that "ensuring regional centers are built to withstand earthquakes may seem reasonable," but CUB questions the timing of such projects.[12] CUB testifies that it is uncertain whether the Company appropriately responded to economic conditions and "reprioritized" such investments to avoid "unreasonable" rate increases.[13]

Q. How do you respond?

A. I disagree both with CUB's general suggestion that the Company does not appropriately consider rate impacts when determining whether to proceed with facilities projects and with CUB's specific suggestion that seismic upgrades are the type of project that should be delayed to avoid "overspend." As I discussed in detail in my Direct Testimony, the planned seismic upgrades are necessary to protect the Company's employees who staff the relevant buildings and the critical infrastructure within the buildings to ensure that NW Natural can respond promptly and effectively and maintain the safety and reliability of its system in the event of a major earthquake. While we cannot and have not sought to address every known seismic vulnerability at the Company's facilities all at once, we have and will continue to prioritize seismic upgrades and complete them in a methodical way. It would not be prudent for the Company to simply delay addressing known seismic concerns when there is a significant chance that a major earthquake will occur in

[11] CUB/200, Garrett/1.

[12] CUB 100, Jenks/6.

[13] CUB/200, Garrett/1, 32.

the region in the next 50 years.[14] While the Company is sensitive to CUB's concern about rising rates, NW Natural disagrees that delaying construction aimed at the health and safety of its employees and the safety and reliability of its system is the proper avenue to explore to cut costs.

Q. Does NW Natural consider the impact to rates when evaluating projects and project costs?

A. Yes, rate impact is a major component of the overall evaluation of any project. We are constantly prioritizing and budgeting to balance the need to complete critical projects with our desire to keep customer rates as low as possible.

Q. How does NW Natural endeavor to complete these essential projects in a way that minimizes the rate impact?

A. NW Natural uses phasing of major projects to mitigate the rate impact of essential improvements, such as the Central RC project and the physical security upgrades. Construction phasing is a strategic approach where a project is completed in distinct phases, rather than all at once. It involves careful planning and execution to ensure that each phase complements the next to keep the project on track without compromising operations. Spacing out the construction in phases benefits customers by spreading the rate impact of the project over time rather than having the full cost of the project enter rates all at once while promptly completing necessary upgrades.

[14] *See* Oregon Office of Emergency Management, "Cascadia Subduction Zone," *available at* https://www.oregon.gov/oem/hazardsprep/pages/cascadia-subduction-zone.aspx ("Currently, scientists are predicting that there is about a 37% chance that a megathrust earthquake of 7.1+ magnitude in this fault zone will occur in the next 50 years. This event will be felt throughout the Pacific Northwest.").

In addition, the Company carefully manages the projects it undertakes to ensure construction is completed in a timely and cost-effective manner, despite the current economic conditions that continue to push costs higher. Projects are identified by the business unit (in this case, the facilities department) for consideration. The facilities projects steering committee reviews all requests, validates the potential need for the projects and determines if the project should be added to the facilities 5-year roadmap for further evaluation. Forecasts for each project are updated quarterly and reviewed by the steering committee, finance team, and officers.

In sum, CUB's concerns about the Company's approach to prioritizing projects and mitigating rate impact are unfounded.

Q. Does this conclude your Reply Testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Reply Testimony of Dina L. Thompson

INFORMATION TECHNOLOGY & SERVICES EXHIBIT 2800

June 4, 2024

EXHIBIT 2800 – REPLY TESTIMONY – INFORMATION TECHNOLOGY & SERVICES

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and position at Northwest Natural Gas Company dba NW Natural ("NW Natural" or "Company").

A. My name is Dina L. Thompson. My title is Director of Enterprise Applications. I am responsible for managing NW Natural's information technology and services ("IT&S") applications, including resource planning, project management and oversight, strategy development, audit compliance, and policy implementation.

Q. Please describe your education and employment background.

A. I received a Master of Business Administration with a focus on information technology management and finance from Portland State University in 2002. I earned my Information Technology Infrastructure Library credential in 2018 and my Project Management Professional certification from the Project Management Institute in 2010. I have worked on financial and IT&S matters in the utility sector since 1999, including for the Bonneville Power Administration and PacifiCorp. Since joining NW Natural in 2006, I have held roles of increasing responsibility concerning NW Natural's IT&S environment, including Senior IT Project Manager, Applications Development Manager, and Interim Chief Information Officer.

Q. Are you adopting the Direct Testimony of Jim R. Downing, NW Natural/700, Downing?

A. Yes.

Q. What is the purpose of your Reply Testimony?

A. The purpose of my Reply Testimony is to respond to the Opening Testimony filed on April 18, 2024, by the Public Utility Commission of Oregon Staff ("Staff")

concerning the Company's IT&S initiatives. Staff is the sole party proposing adjustments concerning the Company's IT&S costs and investments.[1]

Q. Please summarize your Reply Testimony.

A. My Reply Testimony is organized into four parts:

- **First,** I explain why it is appropriate to allow recovery of cost contingencies for major IT&S projects, subject to a final true-up before projects enter rates. Cost contingencies for major projects are generally set at approximately 10 percent of overall project costs,[2] and reflect reasonable allowances for uncertainties in project execution. Contrary to Staff's statement that contingency amounts not yet used in the final months of implementation are unlikely to be needed,[3] projects are more likely to make use of contingency funds in the final stage of implementation and testing. NW Natural commits to update the final costs for all major IT&S projects to reflect the actual amount of contingency costs used before projects are placed in rates.
- **Second,** I provide an update on the Company's major IT&S projects. As part of this update, I respond to Staff's concerns and proposed adjustment regarding the Genesys Re-platform Project. As I explain below, NW Natural prudently moved to re-platform the Genesys software by October 2024 to avoid

[1] I note that the Alliance of Western Energy Consumers filed testimony concerning the depreciation of IT&S accounts. This issue is addressed by Mr. John Spanos, NW Natural/3700, Spanos.

[2] While the Company's contingency guideline for IT&S projects is approximately 10 percent of project costs, this amount may vary depending on the risks associated with an individual project.

[3] Staff also proposes removing contingency funds for the TSA Project, described in NW Natural/800, Downing. The TSA Project is addressed by Company witness Mr. Matt Carlson, NW Natural/2900, Carlson.

exposing this critical infrastructure system to unacceptable security and outage risks. Delaying the project as Staff suggests would have (a) substantially increased project costs, including by forfeiting early contracting incentives; (b) created undue pressure on NW Natural staff resources by overlapping the project with the Company's high-volume call period during the winter months; and (c) increased project risks, including through increased competition for system integrators.

- **Third,** I provide a status update on the Company's hiring of eight new full-time equivalent ("FTE") positions necessary to fill critical gaps in IT&S staffing. One of the eight new positions has already been filled; four more positions are expected to be filled in June and July 2024; and the final three positions are expected to be filled in August and September 2024. I also respond to Staff's proposed adjustment removing the costs associated with four FTEs needed to enable the planned Horizon 2: Vista ("H2: Vista") project and support the current customer information system ("CIS"). As I explain below, prior staffing shortages are not a basis for disallowing necessary FTEs. Each of the new FTEs is crucial to enable successful planning and development of the H2: Vista project and to support the current CIS, and such costs will not be fully encompassed by the Company's planned deferred accounting application.

- **Finally,** I respond to Staff's other IT&S-related requests not associated with a specific rate adjustment:[4]
    1. Software Testing/Training: The Company's policy is to train and test IT&S projects before projects are placed in service. NW Natural has recently instituted a new virtual training environment to help facilitate high-impact software deployments going forward.
    2. IT&S Provider Selection and Consultants: Significant IT&S projects' suppliers are generally identified and sourced through competitive request for proposal ("RFP") processes, unless they are subject to enumerated exceptions in the Company's procurement policy.
    3. Asset Retirements: Following communications with Staff during the discovery process, the Company's asset retirements have been updated to reflect a modified characterization of the Genesys and UI Planner projects.
    4. H2: Vista Deferral: The Company plans to file a deferred accounting application for H2: Vista program costs in the latter half of this year.[5]

[4] Each of the following requests were subsequently also submitted to NW Natural via data requests, numbers UG 490 OPUC DRs 495-498. Staff's question concerning the capitalization of cloud software hosting and licensing costs is addressed in the Reply Testimony of Kyle T. Walker, NW Natural/3800, Walker.

[5] Staff/1000, Dyck/21.

II. COST CONTINGENCIES

Q. Please summarize NW Natural's approach to determining appropriate cost contingencies for IT&S projects.

A. Cost contingencies are designed to address potential cost-related uncertainties in major projects. Some degree of uncertainty is inevitable in any major IT&S effort. NW Natural therefore prudently seeks to account and plan for such uncertainty in developing final project budgets. NW Natural generally uses a cost contingency amount of approximately 10 percent of overall project costs on major IT&S projects, with some variation (either more or less) depending on specific project-related risks. This cost contingency assessment is included in the Company's project planning phase and is incorporated into a project's final projected budget.

Q. What is Staff's proposal concerning the Company's cost contingencies?

A. Staff proposes to remove the contingency funds for five of the Company's major IT&S projects, on the basis that such projects either already have entered service or will be entering service in September or October 2024—and thus, "if the contingency funds have not been used yet, they are unlikely to be used."[6] The specific projects for which Staff proposes to disallow the contingency funds are: (1) the Composition 2.0 Project, (2) the Identity Governance and Administration ("IGA") Automation Project, (3) the Clevest Optimization Project, (4) the

[6] Staff/1000, Dyck/11.

Transportation Security Administration ("TSA") Security Directive 2 Project,[7] and (5) the MapFrame Replacement Project.[8]

Q. Do you agree with Staff that projects in the final months of implementation are unlikely to use their contingency funds?

A. No. On the contrary, it is during the final months of a project's implementation that contingency funds are more likely to be used. Cost contingencies are designed to cover project uncertainties associated with actual implementation. For instance, if issues are discovered during the final testing stage, then additional resources may be required to resolve such issues before the project is fully deployed. While the Company works hard to control costs, some degree of uncertainty in a project's actual deployment is inevitable. NW Natural prudently plans for and manages such uncertainty with limited contingency funds.

Q. Of the four non-TSA projects that Staff identifies, have any of these projects used their contingency funds?

A. Yes. At this time, the Composition 2.0 Project has used its contingency funds. The three remaining projects are still underway, meaning that the use of these projects' contingency funds is not yet certain.

[7] The TSA Security Directive 2 Project is addressed by NW Natural witness Mr. Matthew P. Carlson, NW Natural/2900, Carlson.

[8] Staff/1000, Dyck/9.

Q. Does NW Natural commit to updating the final project costs to include only actually used contingency amounts in rates?

A. Yes. As with prior rate cases, the Company commits to updating final project costs prior to the rate effective date. To the extent that any contingency amounts are included for cost recovery, only contingency amounts that actually get used will go into rates.

III. MAJOR PROJECT UPDATES

Q. Are all major IT&S projects previously described in testimony on track to be placed in service before the November 1 rate effective date?

A. Yes. All eleven major IT&S projects previously described in Direct Testimony have either already been placed in service or are on track to enter service in a timely manner. These projects are also proceeding largely in-line with expected budgets, including contingencies. While I provide additional status and cost updates on each project, below, the Company commits to updating final rate base amounts with actual in-service costs—including any used contingency amounts—prior to the rate effective date.

A. IQGeo Upgrade Project

Q. Please briefly summarize the IQ Geo Upgrade Project.

A. The IQGeo Upgrade Project is a multi-part effort that builds on the new system by (a) upgrading to a newer, fully supported version of IQGeo, (b) re-platforming IQGeo to Azure's enterprise-wide cloud environment, and (c) establishing automated testing for the IQGeo application.

Q. Please provide an update on the IQGeo Upgrade Project.

A. The IQGeo Upgrade Project was placed in service in January 2024.

Q. Are there any cost updates for the IQGeo Upgrade Project in this case?

A. No. This project was placed in service in line with budget parameters.

Q. Does Staff or any other party propose an adjustment related to the IQGeo Upgrade Project?

A. No. Staff witness Ms. Dyck reviewed and analyzed the Company's investment and proposed no adjustment.[9]

B. MapFrame Replacement Project

Q. Please briefly summarize the MapFrame Replacement Project.

A. The MapFrame Replacement Project transitions the Company away from an existing end-of-life software system and develops equivalent functionality in the Company's IQGeo platform.

Q. Please provide an update on the MapFrame Replacement Project.

A. The MapFrame Replacement Project is still on track to be placed in service by September 2024.

Q. Are there any cost updates for the MapFrame Replacement Project?

A. Yes. By refining the project in the planning process, NW Natural was able to significantly reduce overall project complexity, thereby reducing the project timeline and third-party costs. This refinement reduced overall project costs from

[9] Staff/1000, Dyck/12.

$5.5 million to approximately $3.7 million on a system basis ($3.3 million on an Oregon-allocated basis).

Q. Does Staff or any other party propose an adjustment related to the MapFrame Replacement Project?

A. No. Staff witness Ms. Dyck reviewed and analyzed the Company's investment and proposed no adjustment, other than the contingency fund proposal that I discussed earlier in my Reply Testimony.[10]

C. Composition 2.0 Project

Q. Please briefly summarize the Composition 2.0 Project.

A. The Composition 2.0 Project modernizes the Company's electronic and printed documents for customers, including bills, notices, letters, welcome packages, and refund checks. Composition 2.0 is the second stage in the Company's broader modernization effort for customer-facing documents and will create more accessible and consistent documentation across the Company's electronic and printed materials.

Q. Please provide an update on the Composition 2.0 Project.

A. The Composition 2.0 Project is well underway and remains on track to be placed in service in September 2024. Indeed, portions of the project are already complete, including updates to customer letters and refund checks, which are now in production. Other portions of the project are in the user acceptance testing phase, which is one of the final stages of project development.

[10] Staff/1000, Dyck/12.

Q. Are there any cost updates for the Composition 2.0 Project in this case?

A. Yes. The expected cost of the Composition 2.0 Project has increased from $4.4 million to $5.7 million. This cost increase is the result of several factors: (1) additional time required for project development and testing to accommodate the project's complexity; (2) additional digital storage costs for the new documents; and (3) upgrading the underlying software platform to improve system stability and performance. By way of context, the project addresses nine document types with a total of 162 document variations—resulting in close to 1,000 test cases that must be adequately verified and tested, as well as a high volume of documentation that must be reliably stored. As a result, the project entailed greater resources than originally anticipated, raising the total project costs to $5.7 million in capital investment ($5.0 million Oregon-allocated). The incremental ongoing O&M remains at $87 thousand ($77 thousand Oregon-allocated) for hardware and software licensing.

Q. Does Staff or any other party propose an adjustment related to the Composition 2.0 Project?

A. No. Staff witness Ms. Dyck reviewed and analyzed the Company's investment and proposed no adjustment, other than the contingency fund proposal that I discussed earlier in my Reply Testimony.[11]

[11] Staff/1000, Dyck/13.

D. Genesys Re-platform Project

Q. Please briefly describe the Genesys Re-platform Project.

A. The Genesys Re-platform Project migrates the Company's advanced call routing software from the current on-premises Genesys PureConnect platform to the cloud-based Genesys Cloud CX platform. This re-platforming project is necessary to maintain the integrity and reliability of the Company's communications with customers, as the software provider is terminating support for the on-premises solution on July 31, 2025. As I explain below in response to Staff's question regarding IT&S asset retirements, the current on-premises asset is being retired by December 31, 2024.

Q. What is the status of the Genesys Re-platform Project?

A. This project began in 2023, with the initial system integrator ("SI") RFP issued in July 2023. The main SI contract was finalized in January 2024, after which the Company commenced full project implementation. The project is expected to be placed in service in October 2024. As discussed below, this timeline is necessary to (a) constrain overall project costs; (b) minimize impacts on the Company's customer service and essential communications; and (c) limit project implementation risks.

Q. Are there any cost updates for the Genesys Re-platform Project in this case?

A. No. The Genesys Re-platform Project remains on track to be placed in service within budget parameters, including contingency.

Q. Has Staff or any other party proposed an adjustment to the Genesys Re-platform Project?

A. Yes. Staff questions the timing of the Genesys Re-platform Project and proposes a full disallowance of project costs.[12] Specifically, Staff expresses concern that the project "was completed earlier than it need to be" because vendor support terminates on July 31, 2025, whereas the Genesys Re-platform Project will be placed in service by October 2024.[13] Staff asserts that NW Natural should have delayed the project to minimize near-term rate impacts,[14] and suggests that the Company should have continued to use the unsupported software after the July 31, 2025, end-of-support deadline.[15] To support this position, Staff claims that "other software that NW Natural is replacing"—namely IQGeo, MapFrame, and UI Planner—"has been unsupported for years."[16]

Q. As an initial matter, Staff states that "it is unclear what the Company means by 'fully ceasing support and operation of the system'[.]"[17] Please explain.

A. The phrase "fully ceasing support and operation of the system" means that the Genesys vendor will no longer be providing *any* technical support for the on-premises software after July 2025—including security fixes or responses to cyber-

[12] Staff/1000, Dyck/14.

[13] Staff/1000, Dyck/13.

[14] Staff/1000, Dyck/14.

[15] Staff/1000, Dyck/22 (asking whether the existing on-premises Genesys system could "continue to operate after July 31, 2025"). Staff also submitted a separate data request (DR 494) to ask the same question.

[16] Staff/1000, Dyck/14.

[17] Staff/1000, Dyck/14.

attacks. Functionally, this means that, even if the Genesys vendor knows about cybersecurity weaknesses, it will not create security updates, provide mitigations, or even notify customers of those weaknesses after July 2025—posing a significant cybersecurity risk to NW Natural and its customers.

Q. Could NW Natural continue to use the current Genesys platform to serve customers after July 31, 2025?

A. No. It would be extraordinarily imprudent for NW Natural to continue to use the current Genesys platform to serve customers after the system is no longer supported. As explained in Direct Testimony,[18] Genesys is a mission critical system that must be available 24 hours per day, 365 days per year. Consistent up-time for such mission critical applications is essential to protect public health and safety because the system serves to support emergency reporting functions, as well as the full suite of telephonic customer-service communications. Operating such a critical system on a vulnerable platform would be unacceptable from a safety and cybersecurity perspective.

Q. Please respond to Staff's assertion that "other software that NW Natural is replacing has been unsupported for years."[19]

A. None of the three software systems highlighted by Staff—MapFrame, IQGeo, and Utilities International ("UI") Planner—has been "unsupported for years." NW Natural has indeed managed to extend its use of the MapFrame software

[18] NW Natural/700, Downing/24.

[19] Staff/1000, Dyck/14.

despite the software not receiving a software update since 2015. However, the software has continued to have access to essential defect and security fixes in the intervening years. This basic level of support ended on November 30, 2023—less than a year before the MapFrame Replacement Project will be completed. Importantly, this timeframe has been driven by the multifaceted and interdependent transitions associated with the Company's field and web mapping program. In this case, NW Natural could not phase out MapFrame without first upgrading IQGeo—an upgrade which is now complete.

Similarly, the UI Planner Re-platform Project involves a system that became unsupported on January 1, 2024; NW Natural began the project to transition away from the end-of-life system in mid-2023, and expects to place the project in service in August 2024—mere months after support is expected to end. Nor did the Company rely on an unsupported version of IQGeo: the prior IQGeo version had lost full support in 2022, but still had basic support (i.e., essential or security fixes) until June 2024. The IQGeo upgrade was completed in January 2024—six months *before* basic support was lost.

Moreover, none of these projects involves a mission critical application. Minor outages in these programs, while potentially disruptive, would not immediately interfere with the essential provision of service or disaster response. For instance, with respect to the MapFrame Replacement Project, the Company agrees that the current system is considerably outdated. However, the map viewing and correcting functions—while critical to long-term operations—do not require 24x7x365 up-time for public safety. Thus, these upgrade and re-platform

timelines were reasonable given the nature and role of the underlying applications. The Genesys Re-platform Project, in contrast, could not wait.

Q. How did moving forward with the Genesys Re-platform Project in early 2024 reduce costs for customers?

A. Moving forward with the project in early 2024 allowed the Company to reduce project costs in several ways. First, Genesys was providing financial incentives for companies that pursued re-platforming in a timely manner. These incentives were included in the Company's system integrator ("SI") contract. If the Company had not executed the SI contract by January 31, 2024, then $206,479 in incentives were set to expire.

Second, by moving expeditiously to negotiate an SI contract, NW Natural was better able to negotiate discounts. The longer the Company waited to execute an SI contract, the less leverage NW Natural would have had in such negotiations because fewer SIs would be available. As it was, NW Natural was able to negotiate discounts reducing first-year costs by $252,971, and 3-year costs by $349,811.

Third, if the project had been delayed, then the Company would have needed to renew its current services and licensing contract (currently set to expire at the end of 2024). The 2024 services and licensing contract value is $328,000. While the precise value of a renewed contract is unknown, the Company's new contract removes the need for these renewal costs.

Q. How did moving forward with full implementation of the Genesys Re-platform Project in early 2024 minimize customer service impacts?

A. Moving forward with the project implementation in early 2024 allows the project to be placed in service in the autumn—before the winter months and the associated upswing in customer call volume. Re-platforming Genesys entails considerable support from the same staff that maintain the system's day-to-day operations. Thus, overlapping the re-platforming project with the winter season's high call volume would place considerable strain on NW Natural staff, and undermine the resiliency of the system's operations.

To be clear, re-platforming the Genesys system is not a simple switch that can be conducted in just a few months. NW Natural initiated this project in summer 2023 and initiated full project implementation in February 2024. NW Natural expects to place the project in service in October 2024, yielding approximately an 8-month implementation period. If the Company had delayed the project to enter service in July 2025, then it would have needed to begin in November 2024—right when call volumes have begun ramping up. Instead, NW Natural prudently determined to proceed with the Genesys Re-platform Project on a timeline that would allow the project to be complete before winter.

Q. How did moving forward with the Genesys Re-platform Project in early 2024 limit project implementation risks?

A. Moving forward with the project in early 2024 avoided two potential implementation risks by ensuring that the Company could (1) meet the July 31, 2025, end-of-support deadline and (2) retain a competent SI capable of facilitating the re-

platform project. If the Company had delayed the project to deploy right before the deadline, then any issues or delays in project implementation would result in missing the deadline—creating unacceptable cybersecurity risks. Similarly, given that Genesys is a widely used platform, many companies will be competing for SIs to support the re-platforming transition. Delaying the project would have increased the risk of being unable to obtain a competent SI for this crucial project.

E. Start-Stop-Transfer Project

Q. Please briefly summarize the Start-Stop-Transfer Project.

A. The Start-Stop-Transfer Project provides a new web-based tool that will allow customers to seamlessly initiate, terminate, or relocate their service with NW Natural using the Company's website. This project will replace and expand on the existing manual entry forms currently found on the Company's website.

Q. What is the status of the Start-Stop-Transfer Project?

A. The Start-Stop-Transfer Project is now underway and is on track to be completed ahead of schedule in August 2024 (as opposed to the originally anticipated in-service date of October 2024).

Q. Are there any cost updates for the Start-Stop-Transfer Project?

A. No. This project remains on track to be placed in service in line with budget parameters, including contingency.

Q. Does Staff or any other party propose an adjustment related to the Start-Stop-Transfer Project?

A. No. Staff witness Ms. Dyck reviewed and analyzed the Company's investment and proposed no adjustment.[20]

F. Clevest Optimization Project

Q. Please briefly summarize the Clevest Optimization Project.

A. The Clevest Optimization Project is an incremental new effort to optimize and improve the Clevest mobile work management system, including (1) resolving post-deployment issues identified in the product's performance and (2) adding new functionalities that were initially not included but, following the product's launch, turned out to be critical. By expeditiously stabilizing and optimizing the Clevest software, the Company can ensure that the tool continues to provide the best value for the Company and its customers.

Q. What is the current status of the Clevest Optimization Project?

A. The Clevest Optimization Project is well underway. The project is being deployed on a department-by-department basis and more than half of these departments have now received completed updates. The rolled-out enhancements have been well-received, and are now successfully improving the platform's functionality. The project remains on track to be complete by September 2024.

[20] Staff/1000, Dyck/14-15.

Q. Are there any cost updates for the Clevest Optimization Project in this case?

A. Yes. Based on updated statements of work from the project vendor, the Clevest Optimization Project's budget has increased from $7.5 million to $8.6 million on a system basis (or $7.6 million Oregon-allocated), including cost contingency. The Company's previous cost estimate was based on the initial vendor estimate.

Q. Does Staff or any other party propose an adjustment related to the Clevest Optimization Project?

A. No. Staff witness Ms. Dyck reviewed and analyzed the Company's investment and proposed no adjustment, other than the contingency fund proposal that I discussed earlier in my Reply Testimony.[21]

G. Identity Governance and Administration Automation Project

Q. Please briefly summarize the IGA Automation Project.

A. The IGA Automation Project implements a comprehensive new software solution to track and manage the security access and identity management for Company personnel, particularly during onboarding, transfers, and offboarding.

Q. What is the current status of the IGA Automation Project?

A. The Company is on track to place the IGA Automation Project in service in July 2024.

Q. Are there any cost updates for the IGA Automation Project in this case?

A. Yes. Based on actual (rather than estimated) costs, the IGA Automation Project's updated budget increased somewhat from $3.0 million to $3.3 million in capital

[21] Staff/1000, Dyck/15-16.

investment (or $2.9 million Oregon-allocated). These final costs also included higher software licensing costs, increasing incremental ongoing O&M from $113 thousand to $259 thousand ($228 thousand Oregon-allocated).

Q. Does Staff or any other party propose an adjustment related to the IGA Automation Project?

A. No. Staff witness Ms. Dyck reviewed and analyzed the Company's investment and proposed no adjustment, other than the contingency fund proposal that I discussed earlier in my Reply Testimony.[22]

Q. Did Staff express any general concerns regarding the IGA Automation Project?

A. Yes. Staff expressed concern regarding the Company's use of consultants. With respect to the IGA Automation Project, Staff stated "that the process to acquire the IGA Automation Project was convoluted with multiple consultants, including Forrester, with whom they have a subscription, and Integral Partners."[23]

Q. How does NW Natural determine whether to retain outside consultants on a specific project?

A. NW Natural considers several factors in determining whether to retain outside consultants on a specific project, including: (1) whether the Company has sufficient internal expertise on a particular technical issue; (2) whether the Company frequently needs high-level technical expertise in a particular area, or can more

[22] Staff/1000, Dyck/13.

[23] Staff/1000, Dyck/17.

cost-effectively access such expertise through a consulting arrangement; and (3) whether the independence of a third-party consultant will strengthen the impartiality of a particular decision. Indeed, bringing in an outside consultant can be an efficient way to ensure that NW Natural is incorporating industry best-practices—particularly in highly sensitive, security-related areas. Importantly, however, even where the Company determines that retaining outside consulting services is appropriate, the Company rigorously oversees such consultants' scope and performance.

Q. Please respond to Staff's concern regarding the use of consultants on the IGA Automation Project.

A. The IGA Automation Project reflects the Company's effective leveraging of an existing consulting contract to obtain needed outside expertise, coupled with a closely supervised SI contract to ensure effective project implementation. NW Natural determined that we did not have sufficient internal expertise to design the project architecture, which needed to reflect an overarching strategy for identity governance. NW Natural therefore made use of an existing subscription with Forrester Research, which allowed Company staff to access expert research materials and consult with third-party experts. This subscription was made consistent with the Company's established procurement process. This process generally utilizes competitive procurement of goods and services costing more than $100 thousand, but provides for certain enumerated exceptions—such as where a product or service replaces a preexisting, more expensive option. In this case, the Forrester subscription contract was a more cost-effective alternative to

an existing consulting arrangement with the Gartner Group, and therefore was appropriately not the result of an RFP process.

For the project implementation process, the Company conducted a competitive RFP for the SI role. To clarify, an SI is not commonly referred to as a "consultant," as SIs are hands-on technicians experienced with the practical details of project implementation—rather than third-party experts who are retained at a consulting level. In this case, having retained Integral Partners, NW Natural carefully oversaw the SI's implementation activities. The Company committed a dedicated project manager and business lead to focus on the work, including monitoring the consultant's activities, conducting weekly project meetings, and providing monthly reports to the executive sponsor and program steering committee. This oversight process closely mirrors other consultant arrangements, where outside expert services are needed on Company projects.

H. Telemetry Refresh Projects

Q. Please briefly summarize the Telemetry Refresh Projects.

A. The Telemetry Refresh Projects involve surveying, permitting, and deploying new equipment to the Company's remote monitoring and control sites. These projects replace outdated monitoring and control equipment to ensure crucial reliability and safety of the gas supply system.

Q. What is the current status of the Telemetry Refresh Projects?

A. The Company is on track to complete the Telemetry Refresh Projects described here by October 2024.

Q. Are there any cost updates for the Telemetry Refresh Projects in this case?

A. No. NW Natural remains on track to complete this project within budget parameters, including contingency.

Q. Does Staff or any other party propose an adjustment related to the Telemetry Refresh Projects?

A. No. Staff witness Ms. Dyck reviewed and analyzed the Company's investment and proposed no adjustment.[24]

I. Utilities International Planner Re-platform Project

Q. Please briefly summarize the UI Planner Re-platform Project.

A. The UI Planner Re-platform Project entails migrating the Company's UI planning system into the cloud. UI Planner is NW Natural's corporate financial and regulatory finance planning system and is also used by most of the Company's utility peers to perform complex, iterative forecasts and problem-solving. The current on-premises solution is no longer supported by the software vendor. Thus, in order to continue using the UI Planner software, the system must be re-platformed to the modern cloud-based environment—which also requires integrating UI Planner's new cloud-based software product.

Q. What is the current status of the UI Planner Re-platform Project?

A. The Company is on track to complete the UI Planner Re-platform Project by August 2024. As noted below, the replaced on-premises asset will be retired November 1, 2024.

[24] Staff/1000, Dyck/17.

Q. Are there any cost updates for the UI Planner Re-platform Project in this case?

A. Yes. The initial expected $1.8 million cost for this project inadvertently omitted certain project cost components, including resources required to support the project's implementation. The updated expected project cost is $2.4 million on a system basis, or $2.1 million on an Oregon-allocated basis. Incremental ongoing O&M remains at $208 thousand ($183 thousand Oregon-allocated) for software licensing.

Q. Does Staff or any other party propose an adjustment related to the UI Planner Re-platform Project?

A. No. Staff witness Ms. Dyck reviewed and analyzed the Company's investment and proposed no adjustment.[25]

J. PowerPlan Project

Q. Please briefly summarize the PowerPlan Project.

A. The PowerPlan Project transitions a key accounting function, known as the capital settlement process, from the Company's existing PowerPlan tool and into the broader SAP[26] enterprise resource planning system. The capital settlement process tracks costs accumulated under work orders and projects and allocates those costs to various accounts in PowerPlan.

[25] Staff/1000, Dyck/18.

[26] SAP refers to the name of the developer, Systeme, Anwendungen und Produkte in der Datenverarbeitung, which is a German software company.

Q. What is the status of the PowerPlan Project?

A. The PowerPlan Project is now complete, having been placed in service ahead of schedule in March (as opposed to May) 2024.

Q. Are there any cost updates for the PowerPlan Project?

A. No. This project was placed in service within budget parameters.

Q. Does Staff or any other party propose an adjustment related to the PowerPlan Project?

A. No. Staff witness Ms. Dyck reviewed and analyzed the Company's investment and proposed no adjustment.[27]

K. SAP Treasury Project

Q. Please briefly summarize the SAP Treasury Project.

A. The SAP Treasury Project implements an industry-standard software tool to automate and manage the Company's treasury functions—such as financial tracking and payment approval systems. The new tool provides consolidated and comprehensive visibility into the Company's financial risk management using the necessary subset of SAP's "Treasury Track" software functionalities.

Q. What is the current status of the SAP Treasury Project?

A. The Company placed the SAP Treasury Project in service in November 2023.

Q. Are there any cost updates for the SAP Treasury Project in this case?

A. No. This project was placed in service within budget parameters, with contingency.

[27] Staff/1000, Dyck/18.

Q. Does Staff or any other party propose an adjustment related to the SAP Treasury Project?

A. No. Staff witness Ms. Dyck reviewed and analyzed the Company's investment and proposed no adjustment.[28]

IV. IT&S STAFFING NEEDS

Q. Is NW Natural seeking cost recovery for new FTE positions to support IT&S in particular?

A. Yes. NW Natural is seeking cost recovery for eight new IT&S-related FTEs. These FTEs include four application positions, three operational technology positions, and one security position, as shown in Table 1, below:

Table 1

Department	Role	Hire Date
Applications	CIS Senior Developer	July 2024
Applications	CIS Developer	July 2024
Applications	CIS System Analyst 1	May 2024
Applications	CIS System Analyst 2	September 2024
Operational Technology	IT&S Engineer	June 2024
Operational Technology	IT&S Engineer	September 2024
Operational Technology	Applications Engineer 3	August 2024
Security	Information Security Specialist	June 2024

Q. Does Staff propose an adjustment related to the above FTEs?

A. Yes. Staff witness Ms. Dyck proposes to disallow the costs associated with the CIS Senior Developer, the CIS Developer, the CIS System Analyst 1, and the CIS System Analyst 2 because these positions are necessary to facilitate the planning

[28] Staff/1000, Dyck/19.

and development of the H2: Vista program—a program which is not yet in rates.[29] Moreover, Staff asserts that these FTEs should be removed because "NW Natural was able to complete the work of Horizon 1 while being 'understaffed' from their previous request."[30]

Q. Does the Company agree with Staff's proposed adjustment to remove these four CIS FTEs?

A. No. The four new FTEs are fully dedicated to, and will be actively working on, existing NW Natural systems that currently serve NW Natural's customers. These positions are neither temporary nor short-term. These four new CIS FTEs are needed to support the Company's current CIS, and to support the development of the H2: Vista program.

Q. Please expand on why these 4 new CIS FTEs are needed.

A. As the Company explained in its Direct Testimony, the need for these positions has been largely driven by the need to support the prospective H2: Vista program.[31] As the H2: Vista program proceeds, existing personnel will need to be available to develop, test, and implement H2: Vista, meaning that existing CIS support capacity will be substantially under-resourced. In order to effectively support NW Natural's ongoing CIS needs, new personnel need substantial lead times—between 18 and 24 months—to be educated and integrated. As a result, the new FTEs need to be brought on board quickly in order for these individuals to effectively back-fill

[29] Staff/1000, Dyck/20.

[30] Staff/1000, Dyck/21.

[31] NW Natural/700, Downing/51-52.

existing NW Natural personnel for the H2: Vista effort and to support reliable provision of service to customers.

To be clear, however, the need for these FTEs exists regardless of the timing of H2: Vista. For instance, if the current study demonstrated that prerequisite projects would need more time to implement before the larger CIS project was launched, then the need for these new FTEs would be even more crucial, as the Company would need to substantially increase staffing necessary to support long-term reliance on the existing CIS. Existing staffing levels for the current CIS are low, and rely heavily on employees that are nearing retirement age. As explained in UG 388,[32] the existing CIS was developed and customized for the Company over 25 years ago and is both highly complex and requires deep expertise to maintain. Moreover, the CIS programming language is no longer widely used, meaning that those with experience in the relevant language are difficult to find. As a result, new FTEs would need to train extensively to take over for retiring individuals and take on long-term responsibility for the maintenance of the current CIS.

Thus, the need for these FTEs is independent of the H2: Vista program; these positions are essential to ensure that this core system can continue to perform reliably, while also allowing for adequate training time.

[32] UG 388, NW Natural/600, Downing/10-11.

Q. Does the Company's on-time, on-budget deployment of Horizon 1 warrant disallowing FTEs necessary to support H2: Vista?

A. No. NW Natural's on-time and on-budget deployment of Horizon 1 is not a basis for disallowing staffing necessary to support H2: Vista. The IT&S team worked incredibly hard to successfully deploy Horizon 1, despite recognized staffing challenges.[33] Understaffing is not sustainable. It would be neither fair nor prudent to plan to understaff a future crucial infrastructure project.

Q. Staff points out that NW Natural expects to include the cost of these 4 H2: Vista-related FTEs in the planned deferred accounting application.[34] Would this deferred accounting application include all of NW Natural's costs for these positions?

A. No. The planned deferred accounting application will not fully encompass cost recovery for the 4 H2: Vista-related FTEs, as the Company is already prudently filling these positions to ensure adequate training. For these positions, the Company's deferred account would include only those costs incurred prior to the rate effective date.

V. STAFF REQUESTS

Q. Please summarize how this portion of your Reply Testimony is structured.

A. This portion of my Reply Testimony responds to Staff's general requests for

[33] NW Natural/700, Downing/12.

[34] Staff/1000, Dyck/21.

clarification and comment on IT&S matters.[35] Specifically, Staff asks the Company to address (1) the Company's policy for spending time in a training environment for IT&S projects, and whether the time spent in such an environment might be amended; (2) whether IT&S projects and suppliers were contracted for as the result of RFPs; (3) how the Company plans to reflect forecasted retirements for Genesys and UI Planner, including Test Year rate request impacts; and (4) any update on the planned deferred accounting request for H2: Vista.

A. Software Testing/Training

Q. What is NW Natural's policy for spending time in a training environment for IT&S projects?[36]

A. The Company's policy is to train and test IT&S projects before projects are placed in service. However, specific training and testing processes necessarily vary by project. Project-specific training and testing plans are developed for each project before the project is executed. Plans include time in a dedicated virtual training environment, where new projects can be tested and individuals can learn how to effectively use new applications.

[35] Staff/1000, Dyck/22. Staff's question concerning the timing of the Genesys Re-platform Project ("Can Genesys continue to operate after July 31, 2025?") was addressed above, during the discussion of that project. Staff's question concerning the accounting treatment of cloud licensing costs is addressed in the Reply Testimony of Kyle T. Walker, NW Natural/3800, Walker.

[36] Staff/1000, Dyck/22; *see also* UG 490 OPUC DR 495.

Q. Has the Company considered amending the testing/training process in light of the deployment issues experienced in the initial Clevest project?

A. Yes. In fact, the Company has already implemented a new virtual testing and training environment, which allows users to "test drive" new and updated applications without impacting existing NW Natural systems and operations. This virtual testing and training environment has two important benefits for future project implementation. First, the training environment allows individuals the chance to learn and adapt to new applications before the project impacts any real-life, day-to-day operations and activities. Second, by allowing users to preview the application, the Company can solicit feedback and make critical changes before the project goes live. Implementing this new virtual testing and training environment was a major "lesson learned" from the Clevest deployment experience and will facilitate the successful deployment of future projects.

B. IT&S Provider Selection and Consultants

Q. Does NW Natural identify and source outside consultants and providers through competitive RFP processes?[37]

A. Yes, for major contracts and procurements. Pursuant to NW Natural's procurement policy, any asset procurements or consulting contracts exceeding $100 thousand must be conducted through a competitive procurement process, unless subject to certain specified exceptions. Any such exceptions (such as the identification of a more affordable replacement to an existing service) must first be

[37] Staff/1000, Dyck/17; *see also* UG 490 OPUC DR 496.

detailed in a competitive assessment memorandum and approved by the Company's Purchasing department.

C. Asset Retirements

Q. Please clarify how the replaced Genesys and UI Planner assets are reflected in forecasted retirements?[38]

A. Following communications with Staff during the discovery process, the Company's asset retirements have been updated to reflect a modified characterization of the Genesys and UI Planner projects. The current Genesys asset will be retired by December 31, 2024. The UI Planner asset will be retired by November 1, 2024. This update reduces the Company's Test Year rate request by $589 thousand.

D. H2: Vista Deferral

Q. Please provide an update on the Company's planned deferred accounting application for the H2: Vista program.[39]

A. The Company is still planning to file a deferred accounting application for H2: Vista program costs in the second half of this year, which would track and defer the program's significant, non-routine expenses.[40]

Q. Does this conclude your Reply Testimony?

A. Yes.

[38] Staff/1000, Dyck/10, *see also* UG 490 OPUC DR 497.

[39] Staff/1000, Dyck/21; *see also* UG 490 OPUC DR 498.

[40] Staff/1000, Dyck/22.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Reply Testimony of Matthew P. Carlson

TSA PROJECTS
EXHIBIT 2900

REDACTED

Under Modified Protective Order No. 23-480, this exhibit contains SENSITIVE SECURITY INFORMATION and is HIGHLY CONFIDENTIAL in its entirety and has been redacted.

June 4, 2024

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Reply Testimony of Joe S. Karney

METER MODERNIZATION
EXHIBIT 3000

REDACTED

June 4, 2024

EXHIBIT 3000 – REPLY TESTIMONY– METER MODERNIZATION

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I. INTRODUCTION AND SUMMARY

Q. Are you the same Joe S. Karney who presented Direct Testimony in this proceeding on behalf of Northwest Natural Gas Company dba NW Natural ("NW Natural" or the "Company")?

A. Yes, I presented NW Natural/900, Karney.

Q. What is the purpose of your Reply Testimony?

A. In my Reply Testimony, I provide updates to the Company's Meter Modernization Program ("MMP") that have occurred since the time I presented the MMP in my Direct Testimony. I also respond to the Opening Testimony of Public Utility Commission of Oregon Staff ("Staff") witness Dr. Curtis Dlouhy regarding the MMP.

Q. Please provide a summary of your testimony.

A. NW Natural requests the Commission reject Staff's proposed adjustment and approve cost recovery for the Company's MMP. The MMP is a thoughtful approach to combine efforts to replace Periodic Cause for Change ("PCC") meters and Encoder Receiver Transmitters ("ERTs") that have reached the end of their useful life. Staff raises a number of questions about the Company's MMP and the Company's approach to pursuing warranty claims and recommends removing from rate base the net book value of PCC meters that will be removed from service through the MMP, and further suggests that instead of replacing PCC meters, the Company could refurbish its meters to extend their useful life. With respect to investigation of meters and pursuit of warranty claims, my Reply Testimony demonstrates the Company has diligently pursued warranty claims to receive

compensation for faulty meters and meter families when it is economic to do so. My Reply Testimony also demonstrates that Staff's proposal to refurbish diaphragm meters instead of deploying new meters is infeasible, and does not result in the cost reductions that Staff anticipates. Staff also questions the Company's choice to deploy ultrasonic meters in place of diaphragm meters, but my Reply Testimony demonstrates the benefits of ultrasonic meters compared to diaphragm meters and the supply chain issues that have limited the availability of diaphragm meters. Finally, Staff raises concern about the Company's investment in the MMP in an era of decarbonization mandates and electrification opportunities, but my Reply Testimony illustrates that the Company is taking a measured approach that benefits customers. Further, the Company must employ accurate meters to protect customers from inaccurate billing and to comply with Commission mandates for in-service meters. Despite Staff's criticisms of the MMP, Staff does not provide viable alternatives to the MMP that would result in significant additional cost reductions while achieving reliable readings for all in-service meters. My Reply Testimony explains that the MMP is a conservative approach to ensuring in-service meters work properly, and the Commission should approve recovery of the full cost without removing any PCC meters from the rate base.

Q. Do you include any exhibits with your testimony?

A. Yes, I am presenting the following exhibits: NW Natural/3001, Karney (NW Natural Response to OPUC Data Request No. 386), Confidential NW Natural/3002, Karney (Confidential Supplemental Response to OPUC Data Request No. 387 and

Confidential Supplemental Response to OPUC Data Request No. 464), and NW Natural/3003, Karney (proposed calculation of meter net book value).

II. MMP UPDATES

Q. In your Direct Testimony, you indicated that field work to support the MMP will begin in the first quarter of 2024.[1] Did field work begin as anticipated?

A. Yes. The Company's deployment of ERT change outs began in March 2024 and is expected to continue as planned through 2027. The first meter replacements were completed on May 13, 2024.

Q. What is the status of the Company's new software system, Temetra?

A. Temetra has passed through its "proof of concept" phase and is gearing up for its pilot phase. In other words, the Company has completed initial testing and expects to do more controlled testing before fully rolling the system out. We expect that Temetra will be implemented by October 2024.

Q. In your Direct Testimony, you indicated the NW Natural plans to add three full-time employees ("FTE") for the MMP.[2] Has NW Natural hired the FTEs that were identified in your Direct Testimony?

A. Yes. NW Natural has hired all three of the anticipated FTEs, including the Itron Applications Suite Application Engineer 2 and the Metering and Network System Engineer that were in recruitment when I submitted my Direct Testimony in December 2023.

[1] NW Natural/900, Karney/24.

[2] NW Natural/900, Karney/33.

Q. Has there been any update to the anticipated costs of the MMP?

A. No. At this time, the MMP is still on budget, consistent with the anticipated costs presented in my Direct Testimony.

III. REPLY TO STAFF

Q. Please summarize Dr. Dlouhy's testimony concerning the Meter Modernization Program.

A. In its Opening Testimony, Staff criticizes the MMP, raising concerns about warranty claims on existing meters and **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].** Staff also questions whether, if some customers will choose to electrify, replacing and upgrading meters may leave stranded asset costs and not be in customers' best interest.[4] Staff also criticizes the Company's use of ultrasonic meters in the MMP.[5] Though Staff acknowledges that ultrasonic meters may be a sensible choice for placement in a remote location, Staff questions whether switching to ultrasonic meters across the entire service territory is in customers' best interests due primarily to concerns about their 20-year useful life.[6] Staff does not raise any objections to the Company's request for

[3] Staff/900, Dlouhy/55-56.

[4] Staff/900, Dlouhy/52-53.

[5] Staff/900, Dlouhy/51.

[6] Staff/900, Dlouhy/51-52.

FTEs related to the MMP or the need to replace end-of-life ERTs, and agrees that certain MMP costs are appropriately recovered through a deferral.[7]

A. Clarifications / Background

Q. As an initial matter, are there any statements included in Staff's testimony regarding the MMP that warrant clarification?

A. Yes. First, I would like to clarify the scope of the MMP. Staff states that "the MMP would replace meters that run 'fast' – known as Periodic Cause for Change (PCC) meters – and failing Encoder Receiver Transmitter (ERT) devices."[8] It is important to understand that the PCC program and the ERT replacement project are separate initiatives which have been merged through the MMP. The PCC program is an ongoing program and exists year to year–and will exist with or without the MMP.

Q. Why did NW Natural integrate the PCC program and the ERT replacement project for end-of-life ERTs?

A. NW Natural determined that there could be efficiency gains by integrating these efforts. In particular, combining these two programs results in fewer touch points with (and less impact to) the customer. Additionally, because there are fewer touch points and the Company is able to group work by geographic region, the field crews required for these efforts can be deployed more efficiently, which results in lower costs.

[7] Staff/900, Dlouhy/59-60.

[8] Staff/900, Dlouhy/47.

Q. Are there any other statements included in Staff's testimony regarding the MMP that warrant clarification?

A. Yes. In his testimony, Dr. Dlouhy indicates that Staff was concerned that more could be done to verify whether replacing the family was the right decision ex post.[9] Staff acknowledges that NW Natural provided further explanation in response to discovery, which was included as an exhibit to Staff's testimony.[10] To elaborate further on this point, NW Natural performs accuracy testing on each meter that is removed from service, including all PCC meters. This process considers both the individual meters and meter families to determine trends. These test results are recorded for each meter in the Company's Customer Information System.

Q. Does the Company's ex post testing validate the designation of PCC meters?

A. Yes. To evaluate the accuracy of the Meter Sampling Program statistical analysis, these test results are periodically evaluated to ensure that the PCC meters being removed from service exhibit the same performance characteristics of the sample meters upon which the PCC determination was based. If the test results from PCC meters removed from service exhibit statistically significant differences from the sample meters, the Company performs additional analyses to determine the reason for the difference.

[9] Staff/900, Dlouhy/48.

[10] Staff/902, Dlouhy/7 (NW Natural's Response to OPUC DR 386).

Q. Please provide an example.

A. An example of this analysis was discussed in the Company's RG 41 Annual Meter Sampling Program Report for 2022.[11] A modification to the 2005 Perf #572 Sensus R-275 meter family was made after evaluating meter tests for PCC meters removed from service, where specific delivery lots for these meters were determined to be non-conforming, while others were determined to be conforming, resulting in reducing the number of PCC meters by 6,673.

Q. Staff asserts that the Company designates all its meters pre-2020 into various families and subfamilies based on the manufacturer, meter characteristics, and the date that the meter is placed in service, whereas post-2020, families are made solely on the meter manufacture date.[12] Is Staff's characterization accurate?

A. No, it is not accurate for the post-2020 meters. Similar to the pre-2020 meters, they are grouped into families based on the manufacturer, meter characteristics, and the date of manufacture.

[11] NW Natural/3001, Karney.

[12] Staff/900, Dlouhy/49.

Q. Staff also indicates that it holds concerns about whether using ultrasonic meters across the Company's entire service territory would be in customers' best interest should the Company choose to move in that direction in the future.[13] Is the Company proposing to migrate its entire system to ultrasonic meters at this time?

A. No. As I indicated in my Direct Testimony, the Company considered and rejected the possibility of migrating the entire system to use advanced metering infrastructure and ultrasonic meters.[14] Instead, the Company is taking a more conservative approach and replacing the meters identified through PCC and that have end-of-life ERTs.

Q. Staff comments that it is skeptical as to whether it is in the customers' best interest to undertake an aggressive initiative to replace and upgrade all the Company's meters at this time.[15] Is the Company replacing all meters?

A. No. For context, out of approximately 800,000 meters in total, the Company plans to replace 90,000 meters which have been identified as PCC meters. This will occur over the course of the next four years. Of the PCC meters, only 50,000 will be replaced with ultrasonic meters—comprising approximately 6 percent of the meters on NW Natural's system.

[13] Staff/900, Dlouhy/51-52.

[14] NW Natural/900, Karney/27-28.

[15] Staff/900, Dlouhy/51-52.

Q. How is the Company planning to address the meters that require ERT replacements?

A. For the meters requiring ERT replacements, the Company is leaving the existing diaphragm meter in place and simply replacing the ERT. In other words, the Company is not prematurely retiring functional diaphragm meters, and instead is only replacing the component that is at or near end-of-life.

Q. Staff also comments that ultrasonic meters have a useful life of 20 years, whereas diaphragm meters have a useful life of 30 years, and also have a suite of replaceable parts that could extend the useful life of the meter beyond the expected service life.[16] How do you respond?

A. While it is true that diaphragm meters typically have a longer useful life in comparison with ultrasonic meters, it appears that Staff has a misunderstanding regarding the cost and feasibility of replacing parts in diaphragm meters to extend the overall life of the meters.

Q. What is the cost to refurbish a diaphragm meter?

A. The total cost per meter to refurbish a diaphragm meter is $95.49 as shown in Table 1, below. Note this estimate uses an average price on shipping cost as it can fluctuate depending on gas prices.

[16] Staff/900, Dlouhy/51-52.

Table 1. Cost to Refurbish Diaphragm Meter

Labor cost per Meter	$	4.95
Shipping Cost per Meter (roundtrip)	$	5.41
Cost for Refurbishment	$	85.13
Total Meter Shop Cost to Refurbish Meters	**$**	**95.49**

Q. How does the cost to refurbish a meter compare to the cost of a new meter?

A. For 2024, the new diaphragm AC250 meters cost $109.78. In other words, a refurbished meter only would be $14.29 cheaper per meter in comparison with a new meter.

Q. Will manufacturers refurbish all parts of a diaphragm meter?

A. No. Refurbished meters do not receive new diaphragms, and instead only receive repairs to gearing and new gaskets. The diaphragm is a key wear component of the meter, and any degradation in the diaphragm can cause the meter to become inaccurate.

Q. Do manufacturers provide warranties for refurbished meters?

A. Yes, but typically they are limited to only one year. That means that NW Natural could spend the resources to pull the meter from the field, ship it to the manufacturer, pay to have the meter refurbished, and then only get one year of warranty coverage, such that if it failed for any reason outside of the warranty period, NW Natural would incur additional expense to either send it off for repairs *again* or purchase a replacement. Given the expense and resources that would be involved with refurbishing meters, and the limited warranty coverage, it is more effective to replace the meter with a new one—with a 15-year warranty—rather than refurbish the meters.

Q. Staff further states that it expects that, in many cases moving forward, continuing to use diaphragm meters is a more cost-effective way to provide service than a full ultrasonic meter conversion.[17] Does NW Natural agree?

A. Yes, and it is for that reason that NW Natural is not pursuing a full ultrasonic meter conversion. However, NW Natural considers a range of factors in selecting meters, which includes cost, but also considers safety, availability, and diversity of meters in the field. As explained further below, NW Natural currently faces supply chain issues with meters, which has been exacerbated by one of the three meter vendors choosing to limit its offering of diaphragm meters. Despite these challenges, NW Natural is continuing to use diaphragm meters where it is most cost effective and safe to do so, and following the completion of the MMP in 2027, approximately 94 percent of NW Natural's meters will continue to be diaphragm meters. Upon completing the MMP, NW Natural will continue to make meter purchases that prioritize safety, function, and diversity, while remaining sensitive to costs to customers.

Q. Is it possible that diaphragm meter supply will continue to be limited in the future?

A. Yes. Part of the reason why NW Natural is exploring the use of ultrasonic meters is because there are significant supply chain delays associated with diaphragm meters. The total number of vendors for most residential diaphragm meters has dropped from three to two, and there have been significant delays in fulfilling

[17] Staff/900, Dlouhy/51-52.

existing orders and new orders, and there also has been some significant cost increases. In 2021, there were one-year lead times for diaphragm meters, and in 2024, the lead time increased to 1.5 to 2 years.

Q. Did the vendor that stopped selling diaphragm meters leave the market entirely?

A. No. That vendor, Itron, now predominantly sells ultrasonic meters.

Q. How much have the costs for diaphragm meters increased over the past two years?

A. In 2022, the AC250 meter price was $74.83 per meter compared to the current price of $109.78—representing close to a 47 percent increase over approximately 2 years.

B. Reply to Staff's Testimony Regarding Investigation of Problems and Pursuit of Warranty Claims

Q. Staff raises concerns about whether the Company diligently pursued warranty claims for the PCC meters from 2005 to 2009. At the outset, is there any clarification that the Company needs to make?

A. Yes. It appears that there may have been a misunderstanding regarding two of Staff's data requests, OPUC Data Request No. 387 and 464. NW Natural had provided completed warranty claims, but did not provide detail regarding pending warranty claims. Thus, after reviewing Staff's Opening Testimony and recognizing that Staff was looking for a broader scope of information, the Company determined that it would need to update its responses to OPUC Data Request Nos. 387 and 464, and provided Supplemental Confidential Responses to OPUC Data Request

Nos. 387 and 464 on April 26, 2024. The Supplemental Confidential Responses to OPUC Data Request Nos. 387 and 464 provided additional detail regarding the Company's approach to investigation of meter families and pursuit of warranty claims, and are included as Confidential NW Natural/3302, Karney. The Company diligently pursues warranty claims when any meter family has been determined non-conforming and is within its 15-year warranty period. In the case of the meter families from 2005 to 2009, NW Natural pursued warranty claims for each meter family year except for the 2006 meter family, which was out of its warranty period when declared non-conforming. These claims were made as soon as the Meter Sampling Program returned indications that the meter families were non-conforming and manufacturers were promptly notified. The warranty process requires additional sampling and verification efforts that take time to complete. To ensure that the Company remains compliant with meter removal time period requirements in the Meter Sampling Program and General Schedule M-1, meters can be removed from the field ahead of resolution of a warranty claim.

Q. Staff asserts the bulk of the Company's PCC meters appeared to have failed between 2005 and 2008 and seem to come almost exclusively from a single manufacturer.[18] Is this accurate?

A. Yes, Staff's statement is correct. As shown in Figure 2 of Staff's testimony,[19] American/Honeywell was the manufacturer of the PCC meters. The Company

[18] Staff/900, Dlouhy/53.

[19] Staff/900, Dlouhy/54.

further comments that Figure 2 highlights the importance of diversifying the Company's meter complement by adding ultrasonic meters to the system. The Company expects that deploying ultrasonic meters will help alleviate some of Staff's concern regarding reliance on meters that could be subject to similar issues as the meters that have been subject to warranty claims.

Q. Referring to a warranty claim for the 2009 Honeywell AC-250, Staff comments that there was an entire batch of meters from American for which the Company eventually got refunded through the warranty claim.[20] Were these meters fully refunded?

A. No. Due to the timing of the identification of the PCC meters relative to the warranty period, NW Natural's warranty coverage was more limited. For this warranty claim **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

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[20] Staff/900, Dlouhy/56.

Q. Staff also observes that the Company installed a large number of meters from the same manufacturer in each of the prior four years, and comments that it would have been reasonable and prudent for the Company to investigate whether these meters were systematically running fast and whether a warranty claim would be available.[21] How does the Company respond?

A. NW Natural disagrees with the assertion that the Company did not properly investigate the Honeywell/American AC-250 meter families from 2005 to 2009. The Company evaluates the performance of all meter families less than 1,000 cubic feet per hour in size annually in the statistical Meter Sampling Program, and acts immediately if it determines a meter family fails to meet the criteria specified in General Schedule M-1 and Engineering Procedure Z-1. At times during the Meter Sampling Program, the Company noted in different years that the 2005 to 2009 Honeywell AC-250 meter family performance exhibited a trend of fast performance. However, these meter families continued to meet the Meter Sampling Program criteria for satisfactory performance through much of their 15-year warranty life. NW Natural pursued these meters as quickly as possible to determine if they could receive warranty treatment, but also had to meet the manufacturer's warranty requirements before a claim could be made. Even when the Company determined that the meters were non-conforming, it still had to meet manufacturer warranty claim criteria.

[21] Staff/900, Dlouhy/56.

Q. Please describe the warranty claim criteria and process.

A. Honeywell's warranty requires 15 percent of the meter family be determined not accurate before a warranty claim can be issued. The Meter Sampling Program conservatively detects meter families trending fast before they meet manufacturer criteria for a warranty claim. For example, the Company's Meter Sampling Program identified the 2007 AC-250 meter family as non-conforming with 13.3 percent of the sample meters registering fast (greater than 102 percent), when the manufacturer threshold for a warranty claim is 15 percent. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Additionally, if the Company does receive compensation from a warranty claim, the gross plant of the affected meters will be reduced and overall rate base will be reduced. The warranty claims benefit customers by lower return on meter investments as well as lower depreciation expense (return of) those investments in the next rate case and until those meters are retired.

Q. Did the Company investigate the 2005-2009 meters and pursue warranty claims where available?

A. Yes. The Company further investigated and sought warranty claims on meters purchased in 2005, 2007, 2008, and 2009. NW Natural's analysis revealed that:

- A portion of the 2005 meter family was identified as non-conforming and removed from service in 2016 and 2017. A warranty claim was received for 588 meters in the 2005 meter family, as well as meters purchased in 2003 and 2004. The remainder of the 2005 meter family was determined non-conforming in 2021 with 29.8 percent of the meter samples determined fast. This was compared to 12.8 percent the year before.
- The 2006 meter family was determined non-conforming in 2022 (after the 15-year warranty period) with 13.5 percent fast, versus 11.5 percent the year before.
- The 2007 meter family was determined non-conforming in 2022 with 13.3 percent fast, versus 11.5 percent the year before. A warranty claim was filed, and meters are being sent to the manufacturer for validation. They must meet the manufacturer's threshold of 15 percent.
- The 2008 meter family was determined non-conforming in 2020 with 13 percent fast, versus 10.4 percent the year before. A warranty claim was filed, and meters are being sent to the manufacturer for validation. They must meet the manufacturer's threshold of 15 percent.

NW Natural has made warranty claims on a portion of the 2005 meter family, as well as the 2007, 2008 and 2009 meter families.

Q. At what point in the useful life of the meters did the Company pursue warranty claims?

A. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. What did the warranty coverage and claims process entail for this 15-year warranty?

A. The Company provided this information in its response to UG 435 OPUC Confidential DR 301 and attachments. **[BEGIN CONFIDENTIAL]** [redacted] **END CONFIDENTIAL]**.

Q. Does the warranty include replacement of the diaphragm?

A. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. Did the Company receive refurbished meters as part of its warranty claims?

A. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. Are there other costs associated with pursuing meter refurbishment under a warranty claim?

A. Yes, the Company will need to bear the costs of removing the meters from service, packing and shipping the meters, and then resetting the refurbished meters into service. As described above, the refurbished meters have only a limited warranty period (typically one year).

Q. How important is it that the Company have accurate meters in the field?

A. It is extremely important for our business and our customers that our meters give accurate readings. The Company is committed to ensuring its meters are accurate for customers while being cautious about removing meters too soon. Accordingly, the Company only removes meters that meet the criteria for removal.

Q. Do the Commission's rules prescribe a certain level of accuracy for meters?

A. Yes. It is my understanding that OAR 860-023-0015(1) and (2) require meters be accurate within two percent.

Q. Staff also questions whether it is in the best interest of customers to replace these meters rather than to merely repair and redeploy them.[22] How do you respond?

A. As an initial matter, NW Natural does not repair PCC meters and put them back into service. As was discussed above, the costs associated with repair of PCC meters and limited warranty for refurbished meters make this option impractical.

Q. Staff proposes an adjustment to remove from rate base $9.3 million representing the net book value of the PCC meters put into service from 2005 to 2008 for failing to catch PCC meters while they were still under warranty.[23] How do you respond to Staff's adjustment?

A. Staff's proposal is punitive and unfounded. As described above, the Company has diligently investigated its meters from the 2005 to 2008 family years and pursued warranty claims to the extent they were available. Staff has not justified any adjustment to the Company's proposed MMP.

Q. Staff comments that it is difficult to exactly determine the net book value of these meters because the Company relies on group depreciation and groups all meters that were put into service in the same calendar year into a single group. Did Staff calculate its adjustment correctly?

A. With respect to the Company's use of Group Depreciation, Staff is correct regarding the Company's use of the Group Depreciation method. The Reply

[22] Staff/900, Dlouhy/57.

[23] Staff/900, Dlouhy/57.

Testimony of John J. Spanos (NW Natural/3700, Spanos) addresses the depreciable lives of the meters.

While we disagree with Staff's prudency adjustment, with respect to Staff's calculation of the netbook value of the meters, we have reviewed Staff's calculation and found significant errors.

Q. Please describe how Staff calculated the $9.3 million rate base adjustment.

A. The proposed $9.3 million rate base adjustment was calculated using total meter installation costs. Total meter installation costs include the cost of all meters during those periods, ERTs, service lines, risers, regulators, meter fittings, related labor and overheads and other costs incurred. However, only the meters themselves are being replaced.

Q. Do you agree with Staff's methodology and calculation of the net book value of the PCC meters put into service from 2005 to 2008?

A. At the outset, I reiterate my position that any adjustment is not appropriate, and the Company acted prudently in testing its meters and seeking warranty claims. However, in also reviewing Staff's attempt to calculate the net book value of the PCC meters put into service from 2005 and 2008, I have found significant errors in this adjustment. As noted above, the costs used in the calculation include all meter set related costs incurred including assets that are not being replaced (riser, service lines), labor and third-party costs prudently incurred related to the meter sets, and costs related to other meter manufacturers that are not being replaced. The Company believes a more appropriate calculation would be to calculate the actual estimated net book value of only the physical meter assets being replaced.

The Company's records indicate that the average Honeywell meter purchase price during the period in question was $55.62. Additionally, the PCC meter count to be used in the calculation is 47,282 Honeywell PCC meters as opposed to Staff's calculation of 50,330 which represents all meters purchased during 2004-2008 and a reduction of 3,048 meters. The resulting estimated remaining net book value of the physical meters is $1,263,464. Refer to NW Natural/3003, Karney for the proposed calculation. Additionally, it is important to note that the current Depreciation Study already took into consideration the upcoming meter retirements as well as the variability in the useful lives, including meters that are still in service after their estimated useful life.

C. Reply to Staff's Testimony Regarding Drift Adjustment as Alternative

Q. Staff also questions whether it would be more cost effective to apply a drift adjustment rather than replacing PCC meters.[24] Is this a viable option?

A. No. Applying a drift adjustment to PCC meters would not allow the Company to accurately bill its customers, and could result in compounding inaccuracies over time. As the Company explained in its Direct Testimony,[25] providing accurate billing information is an essential component of providing utility service, and the Company strongly disagrees with Staff's suggestion that it should have considered a drift adjustment as an alternative to replacing PCC meters.

[24] Staff/900, Dlouhy/58-59.

[25] NW Natural/900, Karney/15.

Q. Did Staff take a different position on drift adjustments in a recent proceeding?

A. Yes. Staff notes that it highlighted problems with a drift adjustment in Avista's general rate case proceeding in docket UG 461,[26] but now is recommending that the Company should consider the drift adjustment approach in this proceeding.

Q. What concerns did Staff highlight docket UG 461?

A. While some concerns were specific to Avista's drift adjustment, which was called the Installation Constant Factor, Staff also highlighted the following more generalized concerns:

- Meters with incorrect usage are left in the field: Despite evidence that there are meters that are incorrectly reading usage, Avista leaves these meters in service and adjusts the usage to be "correct".
- Full meter families are corrected without evidence that all meters in that family are incorrect: Avista states that when a family of meters is determined to have an increased incidence of incorrect usage, the whole family is corrected using the Installation Constant Factor, despite having no clear evidence that all meters in the family are incorrect.
- Meter testing program delays application of Installation Constant Factor: Avista states that its meter testing program does not start testing meters until 10 years after installation, which is then monitored for increased testing parameters. It

[26] *See In the Matter of Avista Corporation, dba Avista Utilities, Request for a General Rate Revision*, Docket No. UG 461, Staff Opening Testimony, Staff/1300, Nottingham-Shearer-Stevens/6-11 (Jul. 7, 2023).

is possible that some meters do not have the Installation Constant Factor applied until as many as 15 years after installation, and as discussed before, Avista does not begin testing families until the family is 10 years old. Assuming the installation constant factor is an appropriate adjustment, it appears likely some meters will run fast for a number of years before the factor is applied.

- Unique use of an Installation Constant Factor: Avista is proposing the Installation Constant Factor program based off a similar program used by SoCal Gas Company. However, SoCal Gas uses the factor to reduce greenhouse gas emissions caused during the meter change out process, not to correct meters reading incorrectly. Staff has been unable to identify any other companies that use this approach as a replacement for meter testing and replacement program. No tariff was filed by the Company to demonstrate the accuracy of this practice and the potential impact to Avista's Oregon customers.[27]

Q. Did Staff attempt to reconcile these inconsistent positions that were taken less than a year apart?

A. No, Staff made no attempt to do so.

[27] *In the Matter of Avista Corporation, dba Avista Utilities, Request for a General Rate Revision*, Docket No. 461, Staff Opening Testimony, Staff/1300, Nottingham-Shearer-Stevens/11-13 (Jul. 7, 2023).

D. Reply to Staff's Testimony Regarding Use of Ultrasonic Meters

Q. Staff states that it expects that some amount of NW Natural customers will voluntarily choose to electrify for either personal or economic reasons.[28] To date, has NW Natural observed that customers are leaving the gas system to electrify their homes for personal or economic reasons?

A. No, we have not observed this trend. It appears that Staff is speculating regarding possible future electrification scenarios. As described in the Direct Testimony of Messrs. Palfreyman and Kravitz (NW Natural/100, Palfreyman-Kravitz) and Reply Testimony of Mr. Kravitz (NW Natural/2200, Kravitz), the Company is continuing to grow its system and is not observing that customers are leaving the system.[29]

Q. Staff asserts that any customer that receives a meter replacement and opts to fully electrify before the end of the new meter's service life will necessarily leave stranded asset costs that remaining customers are responsible for paying.[30] How do you respond?

A. I fundamentally disagree with Staff's premise that the meter replacements will become stranded assets. The Company has a responsibility to replace failing assets and to ensure it can accurately read meters. NW Natural has an obligation to the customer to accurately bill the customer.

[28] Staff/900, Dlouhy/52.

[29] NW Natural/100, Palfreyman-Kravitz/25-27; NW Natural/2200, Kravitz.

[30] Staff/900, Dlouhy/52.

Q. Staff also states that it is skeptical of the value of transitioning to primarily ultrasonic meters in the long term, and while Staff acknowledges that there may be appropriate use cases for ultrasonic meters, Staff is wary of investing in the highest-grade technology while the Company is also balancing decarbonization obligations.[31] How do you respond?

A. Again, accurate measurement of gas usage is a fundamental part of utility service, and in NW Natural's view, decarbonization is not related to the MMP. The careful and conscientious integration of ultrasonic meters into our meter complement addresses a variety of problems that were discussed in more detail above, namely long lead times and increasing prices for diaphragm meters, shrinking market for diaphragm meter supplies, as well as meter diversification.

Q. Are there other logistical complications associated with procuring additional diaphragm meters?

A. Yes. One particularly challenging aspect of diaphragm meter procurement is that the ERT and meter need to be joined at the meter vendor. As a result, when NW Natural needs additional supply, it has to coordinate procurement and delivery of two separate assets that are experiencing supply chain delays. It has become increasing more difficult for NW Natural to plan the timing of its purchases. Because the ERT is integrated with the ultrasonic meter, the procurement logistics are more streamlined.

[31] Staff/900, Dlouhy/60-61.

Q. What are the current lead times for diaphragm meters in comparison with ultrasonic meters?

A. The current delivery times for diaphragm meters are 1.5 to 2 years, whereas the lead times for ultrasonic meters are six months.

Q. Does this conclude your Reply Testimony?

A. Yes, it does.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibits of Joe S. Karney

METER MODERNIZATION
EXHIBITS 3001 – 3003

June 4, 2024

EXHIBITS 3001-3003 – METER MODERNIZATION

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Joe S. Karney

METER MODERNIZATION
EXHIBIT 3001

June 4, 2024

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NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 386

Please discuss whether the Company performs any ex post testing on a family of PCC meters that were removed.

Response:

NW Natural performs accuracy testing on each meter that is removed from service, including all PCC meters. These test results are recorded for each meter in the Company's Customer Information System. To evaluate the accuracy of the Meter Sampling Program statistical analysis, these test results are periodically evaluated to ensure that the PCC meters being removed from service exhibit the same performance characteristics of the sample meters upon which the PCC determination was based. If the test results from PCC meters removed from service exhibit statistically significant differences from the sample meters, the Company performs additional analysis to determine the reason for the difference.

An example of this analysis was discussed in the Company's RG 41 Annual Meter Sampling Program Report for 2022, included here as UG 490 OPUC DR 386 Attachment 1. A modification to the 2005 Perf #572 Sensus R-275 meter family was made after evaluating meter tests for PCC meters removed from service, where specific delivery lots for these meters were determined to be non-conforming, while others were determined to be conforming, resulting in reducing the number of PCC meters by 6,673. NW Natural continues to evaluate performance of all meters removed from service to ensure accuracy and compliance with the Meter Sampling Program.

Oregon Public Utility Commission

e-FILING REPORT COVER SHEET

COMPANY NAME: NW Natural

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February 22, 2023

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
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Post Office Box 1088
Salem, OR 7308-1088

Re: RG 41: Meter Sampling Program Report for 2022

At the request of Commission Staff, Northwest Natural Gas Company, dba NW Natural, submits herewith its 2022 Meter Sampling Program Report.

As required by our Meter Testing Standards and Procedures document, the accuracies of all operating families of diaphragm meters with capacities 1000 ft^3/hr and below have been statistically analyzed for the year 2022. This analysis utilized all relevant meter tests conducted during the five calendar years between January 1, 2017, and December 31, 2022. The results of this analysis are as follows:

- As of December 31, 2022, 791,368 meters are installed and covered under the Meter Sampling Program. Of these, 695,137 meters, forming 369 distinct meter families, are conforming. The remaining 96,231 meters forming 78 distinct meter families are non-conforming and are scheduled for replacement. 60 non-conforming meter families were identified in prior years and 18 new meter families were identified as non-conforming in 2022. The 96,231 non-conforming meters represent 12 percent of the total meter population.
- Over the course of 2022, the company tested 9,577 meters. Over the five-year period of 2017 through 2022, the company had a total of 37,442 meter samples from which to base its results.
- 369 meter families either had sufficient meter samples to establish statistical confidence in their accuracy, or are new for 2022. These meter families amount to 695,137 meters, or 88 percent of the total meter population. The performances of these families are exhibited in Appendix A.
- 1 meter family, Perf #572, the 2005 Sensus R-275, was previously declared PCC for PCC Year 2022. However, after performing and evaluating the results of 5,569 meter tests in 2021 and 2022, specific delivery lots of these meters were determined to be non-conforming, while other lots remained conforming. Due to this, a population of 6,673 meters were removed from the PCC schedule and will remain in the Meter Sampling Program. As of 12/31/2022, 4,424 meters from specific lots of Perf #572, 2005 Sensus R-275 remain listed for removal in the 2022 PCC program.
- 12 new meter families were added in 2022, reflecting new meters placed in service during the normal course of business, as well as meter replacements to replace non-conforming meters. 8 meter families were removed from service, due to small family size, during the normal course of business. 3 meter families were removed from service due to the number of supplementary samples required exceeding 50% of the family size, with a family size less than 100 meters.

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- 18 meter families, consisting of a total of 70,251 meters at the time of declaration, were identified as not conforming in 2022. Due to the number of meters requiring change-out (8.9% of the total population), these meters have been put on the list to be removed over the course of the next four years, by December 2026, per Meter Sampling Program (MSP) guidelines outlined in NW Natural Engineering Procedure Z-1. The performance of these families is exhibited in Appendix B.
- A further breakdown of the 18 non-conforming meter families and associated meters described above are as follows, the performance of these families is exhibited in Appendix B:
    - 7 meter families, totaling 70,167 meters had sufficient meter tests available to have their accuracy determined statistically and determined non-conforming. Significant results include:
        - 42,486 meters from the 2006 & 2007 American AC-250 meter families make up the bulk of this lot, reflecting the last American AC-250 meters in service from the 2005-2010 timeframe.
        - 13,495 American AL-175 meters from 1987, 1989, 1991
        - 14,106 American AC-250 meters from 1998
    - 8 meter families, totaling 25 meters, will be removed from service due to their small population size and age.
    - 3 meter families, totaling 59 meters, will be removed from service due to a family size less than 100 meters, and sampling requirements exceeding 50% of the total family population.
- Compared to the results above, the Year 2021 report resulted in 35,677 meters being put on the list for removal by December 2025.
- Regarding the planned four year removal of meters determined non-conforming from 2019-2022, the following meters remain:
    - PCC Year 2020 (for removal 2020 to 2023): 2,583 remain out of 42,046 determined
    - PCC Year 2021 (for removal 2021 to 2024): 9,487 remain out of 27,204 determined
    - PCC Year 2022 (for removal 2022 to 2025): 14,977 remain out of 35,677 determined
    - PCC Year 2023 (for removal 2023 to 2026): 69,184 remain out of 70,251 determined
- Consistent with the NW Natural's tariff, bills for meters that are subject to the four year removal schedule and are later found to not meet the accuracy requirement are deemed subject to refund to customers based on the date when the meter family was determined to require change-out to the date the meter was replaced.

RG 41 – NWN Meter Sampling Program Report
February 22, 2023, Page 3
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If you have any questions or comments, please contact me at 503-610-7494.

Sincerely,

/s/ *Michael J. McKenzie*

Michael J. McKenzie, PE
Engineering Manager
cc:

Dan Kizer
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Appendix A
Meter Families in Conformance

Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
120	0	1968	Rockwell	175	54	53	41	2	0	43
120	0	1969	Rockwell	175	53	157	72	5	0	77
120	0	1970	Rockwell	175	52	529	96	9	1	106
120	0	1972	Rockwell	175	50	759	104	8	1	113
120	0	1973	Rockwell	175	49	562	95	10	1	106
120	0	1974	Rockwell	175	48	2383	236	15	7	258
120	0	1975	Rockwell	175	47	1647	145	18	2	165
120	0	1976	Rockwell	175	46	1003	103	6	4	113
120	0	1977	Rockwell	175	45	1228	114	7	1	122
120	0	1978	Rockwell	175	44	1328	121	8	4	133
120	0	1979	Rockwell	175	43	1491	152	10	4	166
120	0	1980	Rockwell	175	42	951	93	9	1	103
120	0	1981	Rockwell	175	41	617	101	7	2	110
120	0	1982	Rockwell	175	40	1094	111	14	1	126
120	0	1983	Rockwell	175	39	1246	122	16	2	140
120	0	1984	Rockwell	175	38	1359	117	14	1	132
120	0	1985	Rockwell	175	37	1818	134	18	1	153
120	0	1986	Rockwell	175	36	1200	109	8	3	120
120	0	1987	Rockwell	175	35	2084	147	6	3	156
120	0	1988	Rockwell	175	34	2035	155	7	5	167
120	0	1989	Rockwell	175	33	3295	218	12	6	236
120	0	1990	Rockwell	175	32	3317	210	15	6	231
120	0	1991	Rockwell	175	31	3598	262	7	13	282
120	0	1992	Rockwell	175	30	6335	398	11	14	423
120	0	1993	Rockwell	175	29	2502	166	8	4	178
120	0	1994	Rockwell	175	28	1285	96	3	4	103
120	0	1995	Rockwell	175	27	268	79	8	0	87
120	0	1996	Rockwell	175	26	703	89	3	0	92
120	0	1997	Rockwell	175	25	123	58	5	1	64
120	0	1998	Rockwell	175	24	45	29	1	1	31
120	0	2012	Rockwell	175	10	1	0	0	0	0

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
120	0	2013	Rockwell	175	9	1	0	0	0	0
120	0	2014	Rockwell	175	8	1	0	0	0	0
120	0	2015	Rockwell	275	7	1	0	0	0	0
120	0	2021	Rockwell	175	1	1	6	0	0	6
125	0	1978	Rockwell	200	44	1454	139	3	1	143
125	0	1979	Rockwell	200	43	142	38	1	0	39
125	0	1980	Rockwell	200	42	1723	126	15	1	142
125	0	1981	Rockwell	200	41	2346	145	10	0	155
125	0	1982	Rockwell	200	40	2923	188	7	0	195
125	0	1983	Rockwell	200	39	1646	141	4	2	147
125	0	1984	Rockwell	200	38	1986	130	14	1	145
125	0	1986	Rockwell	200	36	326	75	3	0	78
125	0	1987	Rockwell	200	35	490	68	3	0	71
125	0	1988	Rockwell	200	34	333	93	4	0	97
125	0	1989	Rockwell	200	33	429	87	5	3	95
125	0	1990	Rockwell	200	32	276	73	10	0	83
125	0	1991	Rockwell	200	31	657	48	0	0	48
125	0	1992	Rockwell	200	30	580	52	2	1	55
125	0	1993	Rockwell	200	29	453	81	6	2	89
125	0	1994	Rockwell	200	28	375	83	6	1	90
125	0	1995	Rockwell	200	27	66	46	5	0	51
125	0	1996	Rockwell	200	26	221	35	0	0	35
125	0	1998	Rockwell	200	24	39	39	3	0	42
125	0	1999	Rockwell	200	23	129	22	0	0	22
125	0	2017	Rockwell	200	5	1	3	0	0	3
125	0	2019	Rockwell	200	3	1	3	0	0	3
130	0	1971	American	175	51	976	92	11	0	103
130	0	1973	American	175	49	686	87	10	2	99
130	0	1975	American	175	47	21	15	0	0	15
130	0	1977	American	175	45	3006	207	24	4	235
130	0	1979	American	175	43	5997	374	20	4	398
130	0	1980	American	175	42	5790	376	24	5	405
130	0	1984	American	175	38	4466	283	40	8	331
130	0	1985	American	175	37	1953	124	13	1	138

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
130	0	1986	American	175	36	3749	201	31	6	238
130	0	1988	American	175	34	2940	184	27	3	214
130	0	1992	American	175	30	1303	93	16	0	109
130	0	1994	American	175	28	2503	119	20	0	139
130	0	1995	American	175	27	459	79	11	0	90
130	0	1996	American	175	26	1010	47	1	2	50
130	0	1997	American	175	25	195	51	1	1	53
130	0	2013	American	175	9	1	0	0	0	0
130	0	2014	American	175	8	3	0	0	0	0
130	0	2016	American	175	6	2	1	0	0	1
130	0	2020	American	175	2	1	13	1	0	14
130	0	2022	American	175	0	1	10	4	1	15
140	0	1968	Sprague	175	54	917	100	0	15	115
140	0	1970	Sprague	175	52	313	47	0	3	50
140	0	1971	Sprague	175	51	884	92	0	11	103
140	0	1972	Sprague	175	50	144	25	0	2	27
140	0	1973	Sprague	175	49	2670	247	3	8	258
140	0	1974	Sprague	175	48	574	51	0	2	53
140	0	1975	Sprague	175	47	664	60	0	3	63
140	0	1976	Sprague	175	46	1009	87	2	5	94
140	0	1977	Sprague	175	45	281	41	0	3	44
140	0	1978	Sprague	175	44	226	39	0	3	42
140	0	1979	Sprague	175	43	121	41	1	1	43
140	0	1980	Sprague	175	42	258	66	5	7	78
140	0	1981	Sprague	175	41	589	47	1	2	50
140	0	1982	Sprague	175	40	514	73	2	3	78
140	0	1983	Sprague	175	39	731	94	3	3	100
140	0	1984	Sprague	175	38	632	66	1	9	76
140	0	1985	Sprague	175	37	1052	105	1	7	113
140	0	1986	Sprague	175	36	908	60	1	3	64
140	0	1987	Sprague	175	35	2754	236	0	13	249
140	0	1988	Sprague	175	34	691	88	3	2	93
140	0	1989	Sprague	175	33	713	51	0	3	54
140	0	1990	Sprague	175	32	960	72	0	2	74

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
140	0	1991	Sprague	175	31	411	42	0	1	43
140	0	1992	Sprague	175	30	528	34	0	3	37
140	0	1993	Sprague	175	29	600	54	0	3	57
140	0	1994	Sprague	175	28	529	61	2	3	66
140	0	1997	Sprague	175	25	449	31	0	0	31
140	0	2016	Sprague	175	6	1	0	0	0	0
270	0	1998	Schlumberger	1000	24	17	11	0	0	11
270	0	2000	Schlumberger	1000	22	17	13	0	0	13
270	0	2001	Schlumberger	1000	21	20	37	2	0	39
450	0	1993	Schlumberger	400	29	166	32	0	0	32
450	0	1996	Schlumberger	400	26	238	38	0	0	38
450	0	1997	Schlumberger	400	25	43	20	0	0	20
450	0	1998	Schlumberger	400	24	397	57	0	1	58
450	0	1999	Schlumberger	400	23	80	21	0	0	21
450	0	2003	Schlumberger	400	19	15	13	0	0	13
450	0	2013	Schlumberger	400	9	1	0	0	0	0
452	0	2003	Actaris	400	19	72	28	0	0	28
452	0	2004	Actaris	400	18	372	86	2	3	91
470	472	1982	American	425	40	16	12	0	0	12
470	472	1983	American	425	39	18	14	0	0	14
470	472	1984	American	425	38	96	22	0	0	22
470	472	1985	American	425	37	21	22	2	0	24
470	472	1986	American	425	36	26	38	1	0	39
470	472	1987	American	425	35	97	60	3	0	63
470	472	1989	American	425	33	17	18	2	0	20
470	472	1992	American	425	30	105	43	2	0	45
470	472	1994	American	425	28	156	69	5	1	75
470	472	1995	American	425	27	73	22	0	0	22
470	472	1996	American	425	26	7	14	1	1	16
470	472	1997	American	425	25	263	78	5	0	83
470	472	1998	American	425	24	128	57	6	0	63
470	472	1999	American	425	23	219	42	2	0	44
470	472	2000	American	425	22	360	55	2	0	57
470	472	2001	American	425	21	49	37	3	0	40

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
470	472	2002	American	425	20	364	80	3	0	83
470	472	2003	American	425	19	137	69	3	0	72
470	472	2004	American	425	18	45	39	4	1	44
470	472	2006	American	425	16	34	35	0	0	35
470	472	2007	American	425	15	184	55	2	0	57
470	472	2008	American	425	14	10	13	0	0	13
470	472	2012	American	425	10	1	0	0	0	0
470	472	2017	American	425	5	1	0	0	0	0
471	0	2007	American	425	15	443	92	8	0	100
471	0	2008	American	425	14	36	35	3	0	38
471	0	2010	American	425	12	73	31	1	0	32
471	0	2011	American	425	11	76	33	1	0	34
471	0	2012	American	425	10	10	0	0	0	0
475	0	1996	American	630	26	1	0	0	0	0
475	0	2010	American	630	12	564	97	11	0	108
475	0	2011	American	630	11	993	82	1	0	83
475	0	2012	American	630	10	1378	100	0	0	100
475	0	2013	American	630	9	1438	94	2	0	96
475	0	2014	American	630	8	1501	83	0	1	84
475	0	2015	American	630	7	1211	73	1	0	74
475	0	2016	American	630	6	1586	67	0	0	67
475	0	2017	American	630	5	1653	70	2	0	72
475	0	2018	American	630	4	4574	165	2	2	169
475	0	2019	American	630	3	2923	111	0	0	111
475	0	2020	American	630	2	891	30	0	0	30
475	0	2021	American	630	1	1139	24	0	0	24
475	0	2022	American	630	0	1422	5	0	0	5
480	486	1989	American	800	33	21	12	0	0	12
480	486	1990	American	800	32	10	18	1	0	19
480	486	1992	American	800	30	18	13	0	0	13
480	486	1995	American	800	27	13	14	1	2	17
480	486	2001	American	800	21	11	10	1	0	11
480	486	2002	American	800	20	16	14	0	0	14
485	0	1981	American	800	41	16	15	0	3	18

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
485	0	1984	American	800	38	44	31	1	1	33
485	0	2016	American	800	6	1	0	0	0	0
487	0	2017	American	800	5	55	5	0	0	5
487	0	2018	American	800	4	187	13	0	0	13
487	0	2019	American	800	3	306	20	0	0	20
487	0	2020	American	800	2	231	12	0	0	12
487	0	2021	American	800	1	339	11	0	0	11
487	0	2022	American	800	0	284	4	0	0	4
500	502	2002	American	1000	20	27	25	2	1	28
505	507	2008	American	1000	14	259	92	11	0	103
505	507	2011	American	1000	11	293	91	7	0	98
505	507	2012	American	1000	10	354	54	2	0	56
505	507	2013	American	1000	9	353	47	0	0	47
505	507	2014	American	1000	8	408	48	0	0	48
505	507	2015	American	1000	7	339	31	0	0	31
505	507	2016	American	1000	6	489	56	0	0	56
505	507	2017	American	1000	5	190	20	0	0	20
505	507	2018	American	1000	4	330	30	2	0	32
505	507	2019	American	1000	3	285	32	1	0	33
505	507	2020	American	1000	2	15	2	1	0	3
505	507	2021	American	1000	1	11	2	1	0	3
505	507	2022	American	1000	0	5	0	0	0	0
510	515	1973	Rockwell	310	49	57	34	1	3	38
510	515	1974	Rockwell	310	48	20	23	0	4	27
510	515	1976	Rockwell	310	46	214	62	3	5	70
510	515	1977	Rockwell	310	45	122	41	1	0	42
510	515	1978	Rockwell	310	44	79	54	1	3	58
510	515	1979	Rockwell	310	43	109	53	5	8	66
510	515	1981	Rockwell	310	41	161	30	0	3	33
510	515	1982	Rockwell	310	40	34	42	1	4	47
510	515	1983	Rockwell	310	39	91	42	1	0	43
510	515	1984	Rockwell	310	38	11	17	1	1	19
510	515	1986	Rockwell	310	36	14	11	0	0	11
510	515	1987	Rockwell	310	35	184	51	1	1	53

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
510	515	1989	Rockwell	310	33	65	34	1	0	35
510	515	1990	Rockwell	310	32	178	68	6	2	76
510	515	1991	Rockwell	310	31	192	26	0	1	27
510	515	1992	Rockwell	310	30	90	50	5	4	59
510	515	1993	Rockwell	310	29	87	19	0	2	21
510	515	1994	Rockwell	310	28	26	16	0	0	16
510	515	1996	Rockwell	310	26	18	20	0	1	21
520	0	1977	Rockwell	415	45	32	16	0	0	16
520	0	1978	Rockwell	415	44	26	17	0	0	17
520	0	1979	Rockwell	415	43	59	33	0	3	36
520	0	1980	Rockwell	415	42	47	37	2	0	39
520	0	1981	Rockwell	415	41	196	30	0	2	32
520	0	1982	Rockwell	415	40	31	16	0	0	16
520	0	1988	Rockwell	415	34	38	16	0	1	17
520	0	1991	Rockwell	415	31	60	17	0	1	18
520	0	1992	Rockwell	415	30	42	29	1	3	33
520	0	1994	Rockwell	415	28	78	21	0	1	22
520	0	1996	Rockwell	415	26	87	49	2	1	52
520	0	1997	Rockwell	415	25	40	17	0	1	18
520	0	2003	Rockwell	415	19	128	31	0	0	31
520	0	2004	Rockwell	415	18	54	43	4	0	47
520	0	2005	Rockwell	415	17	19	27	1	0	28
520	0	2017	Rockwell	415	5	1	0	0	0	0
520	0	2018	Rockwell	415	4	1	0	0	0	0
520	0	2019	Rockwell	415	3	1	0	0	0	0
520	0	2020	Rockwell	415	2	1	1	0	0	1
555	0	1980	American	310	42	47	43	3	0	46
555	0	1981	American	310	41	24	18	0	1	19
555	0	1983	American	310	39	66	51	3	0	54
555	0	1984	American	310	38	148	62	3	1	66
555	0	1985	American	310	37	71	41	2	0	43
555	0	1987	American	310	35	27	33	2	1	36
555	0	1989	American	310	33	7	7	0	0	7
560	0	1985	American	250	37	1358	83	3	1	87

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
560	0	1986	American	250	36	5844	323	7	3	333
560	0	1987	American	250	35	405	31	0	0	31
560	0	1988	American	250	34	3007	136	3	0	139
560	0	1989	American	250	33	6619	374	5	5	384
560	0	1990	American	250	32	5985	288	9	5	302
560	0	1991	American	250	31	5270	279	5	4	288
560	0	1992	American	250	30	4630	155	3	5	163
560	0	1993	American	250	29	3908	156	0	2	158
560	0	1994	American	250	28	5913	186	13	1	200
560	0	1995	American	250	27	7864	270	20	3	293
560	0	1996	American	250	26	10698	375	21	4	400
560	0	1999	American	250	23	10906	273	27	1	301
560	0	2000	American	250	22	10917	319	7	2	328
560	0	2001	American	250	21	9195	217	6	1	224
560	0	2002	American	250	20	8289	187	11	0	198
560	0	2003	American	250	19	394	76	0	2	78
560	0	2005	American	250	17	43	30	1	0	31
560	0	2006	American	250	16	579	67	2	0	69
560	0	2007	American	250	15	179	23	0	0	23
560	0	2012	American	250	10	6	0	0	0	0
560	0	2013	American	250	9	2	0	0	0	0
560	0	2014	American	250	8	5	0	0	0	0
560	0	2015	American	250	7	1	0	0	0	0
560	0	2018	American	250	4	3	14	1	0	15
560	0	2022	American	250	0	1	10	0	0	10
561	0	1984	American	250	38	1	0	0	0	0
561	0	2010	American	250	12	9772	348	8	2	358
561	0	2011	American	250	11	10269	398	5	0	403
561	0	2012	American	250	10	11517	428	3	3	434
561	0	2013	American	250	9	14974	408	4	5	417
561	0	2014	American	250	8	14316	374	4	1	379
561	0	2015	American	250	7	17580	385	1	1	387
561	0	2016	American	250	6	12458	225	0	0	225
561	0	2017	American	250	5	11632	243	2	1	246

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
561	0	2018	American	250	4	9609	172	2	3	177
561	0	2019	American	250	3	14433	197	2	0	199
561	0	2020	American	250	2	10627	109	10	0	119
561	0	2021	American	250	1	6920	70	13	0	83
561	0	2022	American	250	0	6316	32	10	0	42
562	0	2017	American	250	5	22	0	0	0	0
562	0	2018	American	250	4	695	0	0	0	0
562	0	2019	American	250	3	1369	5	1	0	6
562	0	2020	American	250	2	996	0	0	0	0
562	0	2021	American	250	1	1101	2	0	0	2
562	0	2022	American	250	0	567	0	0	0	0
570	0	1989	Rockwell	275	33	682	80	3	0	83
570	0	1990	Rockwell	275	32	5186	200	7	2	209
570	0	1991	Rockwell	275	31	2772	132	7	0	139
570	0	1992	Rockwell	275	30	124	57	5	0	62
570	0	1993	Rockwell	275	29	58	33	1	0	34
570	0	1994	Rockwell	275	28	4881	167	6	0	173
570	0	1995	Rockwell	275	27	6226	240	9	5	254
570	0	1996	Rockwell	275	26	7471	203	3	3	209
570	0	1997	Rockwell	275	25	2298	59	1	0	60
570	0	1998	Rockwell	275	24	5258	166	18	1	185
570	0	1999	Rockwell	275	23	10214	262	35	4	301
570	0	2000	Rockwell	275	22	8251	193	24	3	220
570	0	2001	Rockwell	275	21	8448	218	8	0	226
570	0	2002	Rockwell	275	20	10575	234	2	0	236
570	0	2003	Rockwell	275	19	19336	505	8	1	514
570	0	2004	Rockwell	275	18	3508	91	0	0	91
570	0	2005	Rockwell	275	17	6	7	0	0	7
570	0	2012	Rockwell	275	10	4	1	0	0	1
570	0	2013	Rockwell	275	9	1	0	0	0	0
570	0	2014	Rockwell	275	8	2	0	0	0	0
570	0	2016	Rockwell	275	6	2	0	0	0	0
570	0	2017	Rockwell	275	5	3	3	0	0	3
570	0	2018	Rockwell	275	4	2	2	0	0	2

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
570	0	2022	Rockwell	275	0	1	6	1	0	7
572	0	1999	Sensus	275	23	1	0	0	0	0
572	0	2004	Sensus	275	18	13585	325	22	2	349
572	0	2005	Sensus	275	17	6673	5493	335	7	5835
572	0	2008	Sensus	275	14	34	40	1	0	41
572	0	2009	Sensus	275	13	721	55	1	0	56
572	0	2011	Sensus	275	11	63	20	0	0	20
572	0	2012	Sensus	275	10	3	1	0	0	1
572	0	2013	Sensus	275	9	1	0	0	0	0
572	0	2014	Sensus	275	8	2	0	0	0	0
572	0	2015	Sensus	275	7	2	0	0	0	0
572	0	2016	Sensus	275	6	3	0	0	0	0
572	0	2020	Sensus	275	2	9354	109	3	1	113
572	0	2021	Sensus	275	1	11989	108	0	2	110
572	0	2022	Sensus	275	0	12986	70	2	0	72
585	0	1988	Sprague	250	34	169	22	0	0	22
585	0	1991	Sprague	250	31	681	65	1	0	66
585	0	1992	Sprague	250	30	1989	126	1	1	128
585	0	1993	Sprague	250	29	3673	188	1	0	189
585	0	1994	Sprague	250	28	1598	73	0	1	74
585	0	1995	Sprague	250	27	1442	75	2	1	78
585	0	1996	Sprague	250	26	4262	189	1	1	191
585	0	1997	Sprague	250	25	5721	222	2	2	226
585	0	1998	Sprague	250	24	5200	231	1	1	233
585	0	1999	Sprague	250	23	196	54	1	0	55
585	0	2000	Sprague	250	22	31	29	2	0	31
585	0	2001	Sprague	250	21	47	19	0	0	19
585	0	2002	Sprague	250	20	43	16	0	0	16
585	0	2004	Sprague	250	18	42	20	0	1	21
585	0	2014	Sprague	250	8	2	0	0	0	0
585	0	2021	Sprague	175	1	1	2	0	0	2
590	0	1988	Lancaster	250	34	68	19	0	0	19
590	0	1989	Lancaster	250	33	1237	93	0	0	93
590	0	1990	Lancaster	250	32	1254	79	0	1	80

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
590	0	1991	Lancaster	250	31	1628	107	1	0	108
590	0	1992	Lancaster	250	30	2536	151	2	0	153
590	0	1993	Lancaster	250	29	2740	104	2	0	106
590	0	1994	Lancaster	250	28	4163	232	12	3	247
590	0	1995	Lancaster	250	27	4594	227	13	15	255
590	0	1996	Lancaster	250	26	25	22	0	0	22
590	0	1997	Lancaster	250	25	2042	83	1	2	86
590	0	1998	Lancaster	250	24	15	14	0	0	14
590	0	1999	Lancaster	250	23	96	54	2	0	56
590	0	2016	Lancaster	250	6	1	0	0	0	0
590	0	2019	Lancaster	250	3	1	1	0	0	1
590	0	2021	Lancaster	250	1	1	2	0	0	2
590	0	2022	Lancaster	250	0	1	0	0	0	0
595	600	2000	Schlumberger	250	22	2806	482	22	18	522
595	600	2001	Schlumberger	250	21	3532	324	7	1	332
595	600	2002	Schlumberger	250	20	3098	199	1	8	208
595	600	2003	Schlumberger	250	19	44	18	0	0	18
595	600	2004	Schlumberger	250	18	20	12	0	0	12
595	600	2012	Schlumberger	250	10	1	0	0	0	0
595	600	2016	Schlumberger	250	6	1	1	0	0	1
595	600	2019	Schlumberger	250	3	1	3	0	0	3
602	0	1997	Itron	250	25	1	0	0	0	0
602	0	2016	Itron	250	6	4270	110	0	1	111
602	0	2017	Itron	250	5	4521	98	0	1	99
602	0	2018	Itron	250	4	8079	133	2	0	135
602	0	2019	Itron	250	3	11408	155	0	0	155
602	0	2020	Itron	250	2	21275	211	0	0	211
602	0	2021	Itron	250	1	22427	115	1	0	116
602	0	2022	Itron	250	0	8829	34	0	0	34
603	0	2020	Itron	400	2	421	18	0	0	18
603	0	2021	Itron	400	1	380	7	0	0	7
603	0	2022	Itron	400	0	32	0	0	0	0
					Total	**695,137**				

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Appendix B
Meter Families Not Conforming (To Be Removed Over 4 Years)

Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	% Not Conforming	PCC Reason
130	0	1987	American	175	35	5684	217	36	1	14.6%	Determined
130	0	1989	American	175	33	3116	135	23	4	16.7%	Determined
130	0	1991	American	175	31	4695	183	29	5	15.7%	Determined
130	0	2021	American	175	1	1	5	1	0	16.7%	Small Family
272	0	2004	Actaris	1000	18	7	7	1	0	12.5%	Small Family
300	540	2005	Rockwell	800	17	4	6	0	1	14.3%	Small Family
505	507	1981	American	1000	41	6	8	0	2	20.0%	Small Family
520	0	2000	Rockwell	415	22	80	41	7	0	14.6%	Determined
560	0	1998	American	250	24	14106	301	47	3	14.2%	Determined
560	0	2021	American	250	1	1	16	6	0	27.3%	Small Family
561	0	2006	American	250	16	21038	448	70	0	13.5%	Determined
561	0	2007	American	250	15	21448	534	82	2	13.6%	Determined
570	0	2021	Rockwell	275	1	4	1	1	0	50.0%	Small Family
602	0	1981	Itron	250	41	1	0	0	0	0%	Small Family
602	0	1993	Itron	250	29	1	0	0	0	0%	Small Family
470	472	2005	American	425	17	17	6	1	0	14.3%	Samples >50%
520	0	1987	Rockwell	415	35	35	6	0	1	14.3%	Samples >50%
140	0	1998	Sprague	175	24	7	1	0	0	0.0%	Samples >50%
					Total	**70,251**					

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Joe S. Karney

METER MODERNIZATION
EXHIBIT 3002

REDACTED

Under Commission's General Protective Order No. 23-132, this exhibit is confidential in its entirety and has been redacted.

June 4, 2024

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Joe S. Karney

METER MODERNIZATION
EXHIBIT 3003

June 4, 2024

PCC year	Staff Exh 904 PCC count	Updated PCC count for Honeywell only	Average Cost of Meter 2005-2008	Cost of Meters	Years in service (thru 2023)	Depreciable useful life for FERC 381 - Meters	Estimated remaining net book value in rate base as of 12/31/2023
2005	3,869	3,635	$55.62	$215,194	18	30	$86,078
2006	20,500	19,259	$55.62	$1,140,210	17	30	$494,091
2007	20,863	19,600	$55.62	$1,160,400	16	30	$541,520
2008	5,098	4,789	$55.62	$283,551	15	30	$141,775
	50,330	**47,282**		**2,799,355**			**1,263,464**

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Reply Testimony of Melinda B. Rogers

COMPENSATION & BENEFITS
EXHIBIT 3100

REDACTED

June 4, 2024

EXHIBIT 3100 – REPLY TESTIMONY– COMPENSATION & BENEFITS

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I. INTRODUCTION AND SUMMARY

Q. Are you the same Melinda B. Rogers who filed Direct Testimony in this proceeding on behalf of Northwest Natural Gas Company dba NW Natural ("NW Natural" or the "Company")?

A. Yes, I presented NW Natural/1000, Rogers.

Q. What is the purpose of your Reply Testimony in this proceeding?

A. The purpose of my Reply Testimony is to respond to testimony filed on April 18, 2024, by the Public Utility Commission of Oregon Staff ("Staff") related to employee and officer compensation. Specifically, I will respond to issues presented in the testimony of Staff witness Steph Yamada (Staff/2000, Yamada) and Staff witness Nicola Peterson (Staff/1500, Peterson).

Q. Please summarize your Reply Testimony.

A. In my testimony, I respond to proposed adjustments and concerns raised by Staff on the following issues:

- *Base Pay Escalation for Officers and Non-Bargaining Unit ("NBU") Employees:* In response to Staff witness Ms. Yamada's proposed adjustment, I explain that the Company accurately projected Test Year officer and NBU employees' base pay, relying on detailed surveys and trend data, and that therefore all officer and NBU employees' base pay should be recovered.
- *Base Pay Escalation for Bargaining Unit ("BU") Employees*: I agree with Staff witness Ms. Yamada's proposal to reflect actual negotiated union wage increases for the Test Year. The Company has reached agreement on a new

collective bargaining agreement ("CBA") that has been ratified by BU employees.[1]

- *Pay-at-Risk:* In response to Staff witness Ms. Yamada's proposal to adjust a portion of pay-at-risk, I explain that the Company prudently incurs Test Year costs of $9,340,431 million in pay-at-risk compensation for NBU employees as part of a market median total compensation package and, under standard ratemaking principles, should be recovered in rates.
- *Full-Time Employees ("FTEs"):* In response to Staff witness Ms. Yamada's proposal to adjust costs associated with 20.96 NBU FTEs, including medical costs referenced in Staff witness Ms. Peterson's testimony, I explain why Staff's sole metric for the adjustment (the number of NBU employees per customer) is flawed and that both NBU employee growth and overall FTE growth has been minimal.

II. BASE PAY ESCALATION FOR OFFICERS AND NBU EMPLOYEES

Q. Does Staff propose to adjust Test Year base pay for NBU employees and officers?

A. Yes. Staff recommends a total reduction of $1,473,983 to the Company's base salaries and wages for Oregon, excluding union labor. This amount is Oregon-

[1] The CBA is in the process of being finalized and, therefore, is not attached as an exhibit. However, NW Natural expects a final version to be available soon and will provide a copy either as a supplement to this testimony or in response to a data request.

allocated $956,615 in operations and maintenance ("O&M") expense and $517,368 in rate base.[2]

Q. How does Staff arrive at its proposed adjustment?

A. Staff applies a three-year wage and salary model ("W&S Model") to escalate base pay for NBU employees and officers. Rather than utilizing the Company's Base Year (calendar year 2023), Staff looks to a historical year that is three years prior to the Test Year – in this case 2022. In applying its W&S Model, Staff does not rely on surveys and trend data based on actual market salaries in relevant markets for the same positions. Instead, Staff adjusts NBU employee and officer base pay upward for each subsequent year using the All-Urban Consumer Price Index ("CPI") to establish a projection for the Test Year. The All-Urban CPI is a measure of inflation, i.e., the average change over time in prices paid by urban consumers for goods and services, and does not account for other market conditions that can affect wages and salaries. Finally, Staff compares the results of its W&S Model to the Company's projection of NBU employee and officer pay over the Test Year. Since these amounts differ by less than 10 percent, Staff's position is that the Company should recover half of the difference under a "sharing" principle.[3]

Q. Please describe the Company's methodology.

A. NW Natural uses competitive compensation data to determine compensation for NBU employees and officers. For NBU employees, base pay is determined by

[2] Staff/2000, Yamada/6.

[3] Staff/2000, Yamada/6.

analyzing comprehensive survey data to ensure that it is aligned with the median of the market for comparable jobs with other companies that would typically compete with NW Natural for employee talent. This well-established process demonstrates that NW Natural is offering an appropriate level of base pay to its employees as a component of competitive total compensation. For officers, NW Natural relies on competitive compensation data that include base pay and pay-at-risk comprised of both short- and long-term incentives, and is collected and analyzed annually by an independent compensation consultant, Pay Governance, using peer company, proxy, and survey data.

Q. Does any party criticize or rebut the Company's general methodology for escalating NBU and officer base pay or otherwise challenge the underlying compensation trend studies relied upon by the Company?

A. No. No party criticizes the studies used by the Company or asserts that the Company misapplied the studies or that our general approach is flawed.

Q. Does Staff provide any evidence to suggest that its W&S Model produces more accurate or appropriate base pay estimates for the Test Year than that the data-driven approach used by NW Natural?

A. No. Staff does not produce any evidence to suggest that its W&S Model is better than the Company's methodology.

Q. Do you have concerns with Staff's escalation methodology?

A. Yes. Staff escalates base pay from 2022 using a metric for inflation of consumer goods and services (All-Urban CPI). However, the CPI is not a proxy for actual labor market conditions, and is less tailored and, therefore, less accurate than the

methodology used by the Company. The CPI is not specific to the gas industry or any other defined market from which the Company draws many employees. In contrast, the compensation trend surveys relied on by the Company provide information specific to wages and salaries broken down by position categories and are based upon the relevant hiring market, rather than national averages. In addition, if Staff decides it is still appropriate to use its W&S Model, it should escalate costs from the Base Year—in this case calendar year 2023—not 2022. This treatment would mitigate one of the Company's concerns with Staff's W&S Model and would focus more appropriately on the Base Year and the Test Year, not years prior.

Q. Staff cites a 25-year-old Commission order that states that its W&S Model holds labor costs to inflation, thereby incentivizing the Company to keep labor costs low. Do you agree?

A. No. Since Staff's W&S Model does not reflect actual labor conditions, it is simply inaccurate. For example, in the Company's prior rate case, Staff's W&S Model indicated that the Company's NBU wages should have been higher than what the Company actually proposed.[4] Staff's W&S Model reached the same result for some of Portland General Electric Company's ("PGE's") employees in its last general rate case.[5] These results show that Staff's W&S Model does not necessarily incentivize the Company to keep labor costs low and, in fact, may

[4] NW Natural/3101, Rogers (UG 435 Staff/600, Cohen/11).

[5] NW Natural/3102, Rogers (UE 416 Staff/1300, Jent/13-14).

encourage them to increase such costs beyond what is reflected in the labor market. With the benefit of this experience, NW Natural respectfully requests that Staff no longer rely on its traditional W&S Model. Rather than the static W&S Model that does not examine the conditions of actual labor market, market median compensation analyses should be utilized.

Q. Is Staff's W&S Model consistent with standard regulatory principles?

A. No. Under standard regulatory principles of cost-based ratemaking, the Company should recover all prudently incurred costs. The Company has demonstrated prudence through the fact that it is providing market median base pay to its officers and NBU employees. NBU employee and officer base pay at market median levels is a necessary cost of providing utility service, so there should be no reduction to these prudently incurred costs.

Q. You have presented a detailed critique of Staff's W&S Model—but do you acknowledge that Staff's model has been approved by the Commission in the past?

A. Yes. However, NW Natural has presented a robust case supporting its rate case proposal based on a meticulous, data-driven approach, while Staff has not presented any explanation as to why its approach is more accurate or appropriate. Furthermore, recent experience has shown that Staff's W&S Model is not necessarily more effective at cost control than the Company's approach. Depending on the circumstances, Staff's W&S Model may either be more generous than what the Company believes is warranted in its evaluation of the labor market (as in UG 435 and UE 416) or, as in this proceeding, prevent the

Company from recovering prudently incurred costs that are necessary to provide utility service. Neither circumstance should occur.

Q. If the Commission nevertheless decides to escalate base wages and salaries only commensurate with inflation, is the All-Urban CPI the best inflation metric for this purpose?

A. No, it is not. The West Region Urban CPI is a better reflection of the costs experienced in NW Natural's service territory than the All-Urban CPI, in which Oregon data represent only a very small percent. As Mr. Davilla explains in detail in his Reply Testimony (NW Natural/3500, Davilla), Oregon experiences much higher costs than most other states on many attributes, including wages. As such, the West Region Urban CPI would be a better representation of the measure of inflation that NW Natural employees experience, at least as compared to a national rate. Other organizations agree, most notably the Public Employees Retirement System, or PERS, which is using the West Region Urban CPI as an escalator for its cost-of-living adjustment, or COLA. However, if the Commission were to accept Staff's use of the All-Urban CPI rate, then the Commission should use the most recently released June 2024 report, issued on May 29, 2024. And again, costs should be escalation from the Base Year of calendar year 2023, not the calendar year 2022.

Q. If the Commission relies on the most recent All-Urban CPI report (June 2024), how much would the adjustment proposed by Staff decrease?

A. With this modification, the reduction proposed by Staff would decrease overall by $311,403, of which $202,101 is O&M and $109,302 is capital.

III. BASE PAY FOR BU EMPLOYEES

Q. Does Staff propose to adjust Test Year base pay for BU employees?

A. No. Staff did not make any specific adjustments to base pay for BU employees. However, since the Company's previous CBA with its BU employees expired on May 31, 2024, Staff did recommend that BU wages be updated to reflect actual negotiated union wage increases for the Test Year once those amounts are known.[6]

Q. Does the Company support Staff's recommendation?

Yes. The Company supports Staff's recommendation to update BU wages to reflect actual negotiated union wage increases. Since filing its Direct Testimony in this proceeding, the Company has reached agreement on a new CBA that has been ratified by BU employees.

Q. Please summarize the terms of the CBA that impact revenue requirement.

A. BU employees will receive a six percent wage increase on June 1, 2024. There is an additional four percent increase on December 1, 2024 and every December 1 thereafter through December 1, 2027. BU employee health care costs reflect an 85 percent/15 percent sharing between the employer and employee, whereas previously the sharing was 80 percent/20 percent. Lastly, 51 positions were re-graded, increasing the wages for those positions.

[6] Staff/2000, Yamada/7.

Q. Please briefly summarize the negotiation process for the CBA.

A. **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**.

Q. How do the terms of the CBA compare to NW Natural's estimate in Direct Testimony?

A. Compared to our estimate in Direct Testimony, O&M expense is **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**. Please see Table 1 below for more details:

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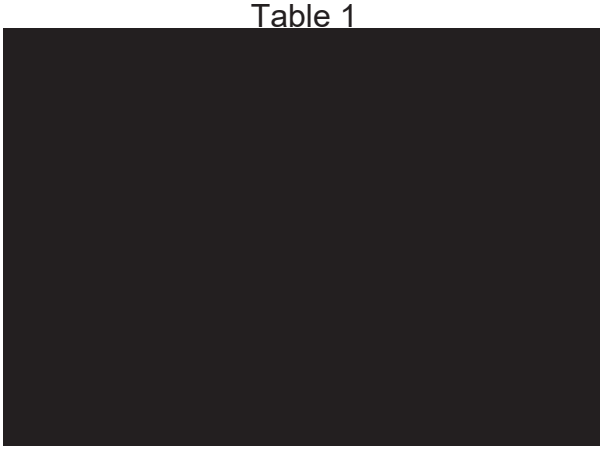
[BEGIN HIGHLY CONFIDENTIAL]

Table 1



[END HIGHLY CONFIDENTIAL]

Q. Does the new CBA impact any other adjustments made by Staff?

A. Yes. NW Natural believes that Staff should no longer propose to adjust any overtime costs. Staff proposed reducing $4,935 of overtime costs ($3,203 in O&M expense and $1,732 in capital). However, the revised amounts for base pay in Table 1 above includes overtime. The reduction in base pay, inclusive of overtime, has a greater reduction than what was in Staff's testimony. Therefore, Staff's overtime adjustment is not appropriate.

IV. PAY-AT-RISK FOR NBU EMPLOYEES

Q. Does Staff propose to adjust Test Year pay-at-risk for NBU employees?

A. Yes. Staff recommends an Oregon-allocated reduction in NBU pay-at-risk of $3,186,968 in O&M expense and $1,723,614 in rate base. As explained in Direct Testimony, NW Natural is not seeking recovery of officer bonuses to limit the size of its rate request.[7]

[7] NW Natural/1000, Rogers/9.

Q. How does Staff arrive at its proposed adjustment?

A. Staff states its proposed adjustments are consistent with past Commission practice, arguing that the Commission disallows 50 percent of merit-based bonuses for NBU employees because they equally benefit shareholders and customers.[8]

Q. Does the Company agree with Staff's approach to NBU pay-at-risk?

A. No. Staff seeks to disallow recovery for significant portions of pay-at-risk costs it presumes are designed to incentivize employee behavior that primarily or solely serves shareholder interests. Its proposed adjustments reflect a general philosophy that the interests of shareholders and customers are zero-sum and segregable, and accordingly, that a cost should not be recoverable to the extent it may benefit shareholders. NW Natural understands there is Commission precedent for imposing flat percentage disallowances such as those recommended by Staff. Nevertheless, standard regulatory principles support moving away from basing disallowances on flat percentages, which discourages best practices for employee compensation and results in a substantial disallowance of prudently incurred, reasonable and necessary business expenses that form part of the utility cost of service.

[8] Staff/2000, Yamada/11.

Q. Are the costs that the Company incurs for its NBU pay-at-risk programs prudently incurred and necessary business expenses that form part of the utility cost of service?

A. Yes. First, as explained in my Direct Testimony,[9] the Company structures employee compensation, including base pay and pay-at-risk, to ensure both individual elements and the total compensation package are comparable to market levels. Competitive pay helps the Company attract and retain qualified employees and officers, which is necessary to ensure the Company operates a safe, reliable, cost-effective, and customer-responsive gas distribution business.

Second, the pay-at-risk program costs that NW Natural has included in its requested revenue requirement are structured to compensate employees for achieving baseline targets tied to standard business operations, not for exceptional performance going above and beyond the call of duty.[10] By contrast, the costs associated with incentive programs rewarding extraordinary performance are not included in the requested revenue requirement, as the Company proposes these be absorbed entirely by shareholders. For the pay-at-risk programs at issue in this proceeding, employees receive their pay-at-risk as a result of achieving normal, expected levels of performance, both individually and for the Company as a whole. In fact, every NBU employee's compensation package incorporates some element of pay-at-risk, not just those employees whose positions officially require them to

[9] NW Natural/1000, Rogers/10-12.

[10] NW Natural/1000, Rogers/8-10. NW Natural/1003, Rogers.

consider shareholder implications. Funding for pay-at-risk at target levels is therefore expected and included in annual budgeting. Because the Company is well-managed, in the ordinary course employees and officers generally receive their pay-at-risk compensation. In other words, it is typically only when individual and/or Company performance is sub-par that employees see a reduction in their total compensation package through reductions to or elimination of pay-at-risk. Accordingly, pay-at-risk payouts represent the steady state of operations. The total compensation package under those normal circumstances, inclusive of salaries and pay-at-risk payouts, is a necessary cost of operating the utility business.

Q. You mentioned above that pay-at-risk payouts represent the steady state of operations. That being the case, why does the Company continue to place this portion of compensation in an "at risk" category, rather than shifting all compensation to base pay?

A. Placing a portion of an employee's total compensation at risk is a standard best practice in the human resources field. Pay-at-risk is widely incorporated into the compensation packages offered by competitors, preferred by the industry, and expected by the workforce. When implemented effectively, pay-at-risk helps to motivate strong performance, increase productivity, reduce problematic behaviors, communicate to employees they are valued, give them a greater degree of control over their salary, and improve morale and retention.

Q. From the Company's perspective, is an effort to segregate customer benefit from shareholder benefit the right approach for determining the extent to which pay-at-risk compensation costs should be recoverable?

A. No. While shareholder and customer interests may occasionally diverge on a particular issue in a particular case, in general, shareholder and customer interests are aligned when it comes to business operations and the overall health of the Company, as the provision of adequate service is a core pillar for sustaining a gas distribution service.

Q. Can you elaborate on the relationship between work performance and customer benefit?

A. There is a clear connection between incentive-based compensation, employee work performance, and the service that customers ultimately receive. It is indisputable that safety, reliability, rates, and customer service all are affected by how employees perform on the job. For example, when a customer service employee resolves a customer issue efficiently, the customer benefits directly, while shareholders benefit from lower costs and increased customer loyalty.

Q. In addition to short-term incentives, Staff also proposes to disallow 50 percent of restricted stock units ("RSUs") provided to NBU employees.[11] Please explain why RSUs should be eligible for full cost recovery.

A. The purpose of RSUs is to encourage key NBU employees to remain with the Company, which is why they vest over a number of years. While RSUs will not

[11] Staff/2000, Yamada/12-13.

vest if the Company has a very poor year, it is designed to ensure that NW Natural retains qualified employees.

Q. Staff also proposes to disallow 50 percent of the Employee Stock Purchase Plan ("ESPP") provided to NBU employees.[12] Please explain why the ESPP should be fully recovered.

A. The ESPP encourages employees to provide customers with efficient natural gas service. By encouraging employees to own shares in NW Natural, the interests of employees and the Company are better aligned, helping to maintain strong performance and increased productivity.

In addition, NW Natural must compete for talent with other utilities that offer ESPPs, as well as other businesses where they are also common. In a very tight labor market, the Company must both retain and attract qualified employees, and continuing programs, such as the ESPP, that encourage employees to continue to perform strongly and provide service more efficiently is very important.

V. FTES

Q. Does Staff propose to adjust the number of FTEs in the Test Year?

A. Yes. In Direct Testimony, NW Natural proposes to include 1,183 employees in the Test Year.[13] Staff proposes a blanket reduction of 20.96 FTEs on an Oregon allocated basis,[14] which I will address in my Reply Testimony. Staff also proposes to exclude four of the eight proposed new Information Technology & Services

[12] Staff/2000, Yamada/11.

[13] NW Natural/1000, Rogers/22.

[14] Staff/2000, Yamada/16.

("IT&S") FTEs and four of the five proposed new decarbonization FTEs, which are addressed in the Reply Testimony of Dina L. Thompson (NW Natural/2800, Thompson) and the Reply Testimony of Zachary D. Kravitz and Kyle N. Griffiths (NW Natural/3600, Kravitz-Griffiths), respectively.

Q. Please explain Staff's rationale for disallowing 20.96 FTEs on an Oregon allocated basis.

A. Between 2021 and 2023, Staff claims that the Company served an average of 1,469.9 customers per FTE at the Oregon level. Based on the projected customer count of 702,022 in Oregon at the end of the Test Year, Staff claims that this 3-year average number of customers resulted in a total of 481.0 NBU employees, whereas the Company's Test Year proposal reflects 506.4 FTE in Oregon. This difference is 25.4 NBU FTEs. After adding back in the five new IT&S and decarbonization FTEs that Staff recommends allowing into rates, the disallowance is 20.96 FTEs on an Oregon-allocated basis.

Q. Does the Company agree with Staff's adjustment?

A. No. First, the Company notes that its proposal results in only modest NBU employee growth compared to 2021-23 levels. An additional 20.96 Oregon-allocated FTEs represents only a 4.3 percent increase in NBU FTEs and a 2 percent difference in the overall number of FTEs. Staff also does not explain: 1) why a blanket disallowance based on the number of customers per FTE is appropriate, 2) why NBU, union, and officers are separated into different categories, or 3) why some growth is permitted for union employees (1.2 percent) but none is permitted for NBU FTEs. Instead, to support its adjustment, Staff cites

to a single order, Order No. 99-033, involving PGE. However, the facts in that case are very different from what is presented here. At the time of the order, PGE proposed to transition away from being a vertically integrated utility to a distribution-only utility, which would affect the number of FTEs. Staff used the FTE per customer trendline to establish what PGE's number of FTEs should be as a distribution-only electric utility instead of a vertically integrated one. To calculate this number, Staff developed a trend analysis of FTEs per customer between 1991 and 1997. The same circumstances are not present here. NW Natural is not proposing to restructure. Therefore, the Commission principle that was adopted in that order is not present here:

> "These [FTE] levels should be limited to levels forecasted as a function of customers per FTE **applied to the restructured utility.** "[15]

Again, NW Natural is not a restructured utility and, accordingly, the Order No. 99-033 principle does not apply to NW Natural.

Second, over the long-term, NW Natural's customers/employee ratio has greatly decreased over time. On a system level, for example, in 2005, NW Natural had 1,305 employees in total (NBU, BU, and officers), which worked out to an employee for every 473 customers. In almost two decades since that time, that number has risen to 658 customers per employee. Due to a lack of a readily available information over this timeframe, this metric differs somewhat from Staff because it looks at customers per employee, not customers per FTE. For

[15] *In the Matter of PGE's Request for a General Rate Revision,* Docket No. UE 102, Order No. 99-033 (Jan. 27, 1999) (emphasis added) (available at: https://apps.puc.state.or.us/orders/1999ords/99-033.htm).

example, NW Natural would count two half-time employees as two employees, whereas Staff would count them as one FTE. Nevertheless, NW Natural does not believe it is appropriate for Staff to only look at the last three years (and only at NBU FTEs), where the Company's trendline shows an increasing number of customers served per employee.

Third, and perhaps most importantly, our FTE footprint is not directly tied to the number of customers served. NW Natural needs to have a workforce to meet the needs of its customers and, as such, FTE levels may fluctuate over time. Similarly, the composition of the workforce (i.e., the number of BU and NBU employees) will shift over time to meet changing needs and demands. NW Natural considers 4.3 percent growth in NBU FTEs and 2 percent overall growth in FTEs compared to 2021-2023 to be relatively modest, especially compared to historical trends.

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Q. Regarding benefits, Staff witness Peterson states proposed medical benefit adjustments due to Staff witness Yamada's adjustment of 20.96 FTEs. Staff witness Pederson states that "Staff also is only proposing an adjustment to O&M expense based on the Staff-proposed adjustment to FTEs," and that "further clarification is required prior to recommending an adjustment to capitalized benefits or before Staff can draw conclusions regarding the overall level of costs."[16] Please respond.

A. As explained above, NW Natural disagrees with Staff's proposed FTE adjustment and, therefore, the corresponding adjustment to medical benefits. In response to Staff's specific concern, the Company clarified that its medical benefits are all included in the Company's Payroll Overheads. NW Natural is happy to provide further clarification informally or through the formal data request process.

Q. Does this conclude your Reply Testimony?

A. Yes, it does.

[16] Staff/1500, Peterson/5.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibits of Melinda B. Rogers

COMPENSATION & BENEFITS
EXHIBITS 3101 – 3102

June 4, 2024

EXHIBITS 3101-3102 – COMPENSATION & BENEFITS

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Melinda B. Rogers

COMPENSATION & BENEFITS
EXHIBIT 3101

June 4, 2024

CASE: UG 435
WITNESS: HEATHER COHEN

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 600

Opening Testimony

April 22, 2022

Docket No: UG 435 Staff/600
Cohen/1

Q. Please state your name, occupation, and business address.

A. My name is Heather Cohen. I am a Senior Utility Analyst employed in the Rates, Finance and Audit (RFA) Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/601.

Q. What is the purpose of your testimony?

A. I provide background, analysis, and recommendations regarding the Company's Test Year expense for wages, salary, incentives, and full-time equivalents (FTE). I also address the Company's Test Year expense for customer account, customer services, sales expenses as well as some miscellaneous Operation and Maintenance(O&M) expenses.

Q. How is your testimony organized?

A. My testimony is organized as follows:

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Docket No: UG 435

Staff/600
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ISSUE 1. WAGES, SALARIES AND FTE

Q. Please provide a summary of the Commission's historical method for determining the amount to include in a utility's revenue requirement for wages, salaries, incentives, and overtime expense.

A. The Commission's methodology has many components. The Commission determines the appropriate level of wages and salaries for employees in the Test Year using its three-year wage and salary (W&S) model to estimate union and non-union payroll levels for energy utilities.[1,2] The model determines an appropriate level of Test Year expense and capital investment for wages and salaries by escalating the Company's base year wages and salaries by annual changes to the All-Urban CPI (for non-union) or negotiated increases (for union) and applying a sharing mechanism between the wages and salaries determined by the W&S model and the wages and salaries proposed by the utility.

To determine the appropriate amount to include in revenue requirement for incentives paid to employees, the Commission's policy is to disallow 100 percent of officers' bonuses because they are typically based on increased

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1 *In the Matter of Northwest Natural Request for a General Rate Revision*, Docket No. UG 132, Order No. 99-697 at 43 (November 12, 1999); and *In the Manner of PacifiCorp* dba Pacific Power *Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 at 102 (December 18, 2020).

2 *See Pacific Power & Light*, Docket No. UE 116, Order No. 01-787 at 40 (September 7, 2001); *Northwest Natura*l, Order No. 99-697 at 43; *In the Matter of the Application of Portland General Electric Company for Approval of Customer Choice Plan,* Docket No. UE 102, Order No. 99-033 at 61 (January 27, 1999); and *In the Matter of the Revised Tariff Schedules for Electric Service in Oregon filed by Portland General Electric Company,* Docket No. UE 88, Order No. 95-322 at 10 (March 29, 1995).

earnings, which benefit shareholders.[3] It is also Commission policy to disallow 75 percent of performance-based bonuses because they are generally focused on increased earnings and therefore bring more benefit to shareholders. The Commission disallows 50 percent of merit-based bonuses because they equally benefit shareholders and ratepayers. Union bonuses are treated in the same manner as non-union bonuses.[4]

Finally, the Commission determines the appropriate ratio of expense and capital to apply to the total forecasted compensation and applies it to determine what compensation expense that is included in Test Year expense and what compensation is included rate base.

Q. Please explain how Staff used the Three-Year W&S model to arrive at its recommendation for wage and salary levels for the Test Year.

A. As a starting point for determining non-union wages for each employee class, the W&S model uses the utility's actual wage, salary, and overtime levels as they existed three years prior to the Test Year.[5] For example, a 2022 Test Year would require a Base Year of 2019. From there, the Base Year wages and salaries are adjusted by a year-over-year escalation of expenses using the All-Urban CPI for each of the three subsequent years to establish a forecast of Test Year wage and salary levels.[6]

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3 See *Northwest Natural,* Order No. 99-033 at 62; and *In the Matter of the Application of US West Communications, Inc. Application for an Increase in Revenues*, Docket No. UT 125, Order No. 97-171 at 74-76 (May 19, 1997).
4 *See PacifiCorp*, Order No. 20-473 at 97; *Northwest Natural,* Order No. 99-697 at 44-45; and *PGE,* Order No. 99-033 at 62.
5 See *Northwest Natural,* Order No. 99-697 at 43.
6 *Ibid*.

In effect, the model calculates the average salary based on the Company's actual Base Year calendar payroll (2020), divided by the actual Base Year FTE (2020), then escalates the average by the annual changes to the All-Urban CPI for 2021, 2022, and 2023. Once the escalated amount is determined, it is compared to the Company's Test Year figures.[7] At this point the sharing principle is applied, wherein Staff adjusts its forecasted amount to allow the Company to share 50/50 the lesser of the difference between the model forecast and the amount the Company has included in its Test Year or a 10 percent band around Staff's projection.[8]

For non-union wages, the W&S model incorporates actual market-based data by using historic wages and adjusting for inflation using the All-Urban CPI index.[9] The Commission has consistently validated the All-Urban CPI to adjust historic wages and salaries as "adjusting payroll levels by changes in inflation provides employees the same real level of compensation as in the base year and provides an incentive to companies to minimize labor costs."[10] Further, the methodology of equally dividing between ratepayers and shareholders the difference between the utility's Test Year forecast and the forecast obtained by the model allows for some adjustments to reflect changes in market conditions without allowing unchecked escalation.[11]

7 Ibid.
8 Ibid.
9 Ibid.
10 Ibid.
11 *PGE,* Order No. 95-322 at 10.

For union wages, the W&S model again starts with actual wages three years before the Test Year. Rather than escalating the wages using All-Urban CPI, wages are escalated using negotiated wage increases as set forth in union contracts, and Staff's final adjustment incorporates any sharing between the Company's Test Year forecast and the forecast obtained under the W&S model.[12] In Order 20-473 (2020) in PacifiCorp's general rate case, the Commission rejected Staff's proposed 50/50 sharing between Staff's Test Year determination of expense for union wages and salaries and the Company's projection. The Commission concluded that the arms-length nature of the negotiations regarding wages was sufficient protection for ratepayers.[13]

Q. Please summarize Company's proposal for wages, salaries, incentives and overtime expense in this case.

A. The Company's 2023 Test Year includes $106 million in wages and salaries (base pay), $11.5 million in incentive compensation, and $6.8 million in overtime.[14] While the Company's initial testimony reported a total of $11.3 million in incentives, the Company corrected their Non-Exempt Restricted Stock Units (RSU) amounts to $437,254.[15] The Oregon allocation factor is 100 percent with a O&M/Capital split of 59.8/40.2.[16]

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12 *See Northwest Natural,* Order No. 99-697 at 43.
13 See *PacifiCorp,* Order No. 20-473 at 94.
14 NW Natural/800, Rogers/5, 17.
15 Staff/602, Cohen/4, NWN Response to Staff DR 265, Tab 267/269, Footnote 2 (electronic spreadsheet).
16 Staff/602, Cohen/1, NWN Response to Staff DR 93.

FIGURE 1: INCENTIVES FROM COMPANY TESTIMONY

Original	Executive	NBU
Short Term Incentive		
O&M	526,519	4,550,462
Capital	466,688	2,987,243
	993,207	7,537,705
State Allocation	88.29%	89.26%
OR Utility Short Term Incentive Comp	876,910	6,727,889
OR LTIP (O&M)	2,109,952	145,372
OR Stock Expense (O&M)/RSUs	1,276,553	135,547
OR Pay At Risk	**4,263,415**	**7,008,808**

Corrected	Exec	NBU		Total
OR LTIP	2,109,952	145,372		2,255,324
OR RSUs	1,276,553	437,254	*	1,713,807
OR Short Term Incentive	876,910	6,727,889		7,604,799
Total	**4,263,415**	**7,310,515**		**11,573,930**

*See DR 265 Tab 267/269 foonote 2, Company corrects non-exempt RSUs to $437,254

The Company states it removed half of the officer short-term incentives associated with net income from its proposed Test Year.[17] However, also included in the Test Year Operations and Maintenance expense is $1.9 million of stock expense, which includes the employee stock purchase plan as well as $2.3 million of the Long-Term Incentive Plan for Officers and key employees.[18] With respect to officer incentives capitalized in plant since the effective date of NW Natural's last general rate increase (November 1, 2020), Staff included incentives in the last two months of 2020 and the entirety of 2021. Staff calculates Northwest Natural's proposed Revenue Requirement includes total officer incentives capitalized in plant for that period at $954 thousand.[19]

Q. How does the Company determine the compensation for employees?

[17] NW Natural/800, Rogers/5.
[18] NW Natural/1200, Davilla/18.
[19] Staff/602, Cohen/8, NWN Response to Staff DR 344 (electronic spreadsheet).

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A. NW Natural testifies that it uses third party survey data completed in 2020 to ensure base pay midpoints are at the median of comparable companies for Non-Bargaining Unit (NBU) employees. Bargaining Unit (BU) employee pay is determined through a negotiated process that uses comparable market survey data and union contracts as points of comparison for setting wage steps. The Company uses compensation data provided by independent compensation consultant Pay Governance to set officer pay.[20]

In addition to base pay, the Company offers the following incentives:

- Goals Incentive Program: Offered to NBU non-officer employees for those who meet or exceed their annual performance objectives.
- Employee Stock Purchase Plan: Allows employees to purchase common stock at 85 percent of closing price.[21]
- Executive Annual Incentive Plan: Short-term incentive program or cash-payments for Officers that is based on a weighted formula of 70 percent Company Performance Factor (71.43 percent Net income and 28.57 percent Operations) and 30 percent Priority/Individual Goals (which includes a Return on Invested Capital (ROIC) component).[22]

[20] NW Natural/800, Rogers/4.
[21] NW Natural/800, Rogers/9-11.
[22] NW Natural Schedule 14A Proxy Statement, April 15, 2021, https://www.sec.gov/Archives/edgar/data/1733998/000119312521117464/d45834ddef14a.

- NBU Short-Term Incentive Plan: Offered to non-officers and is based on customer service, company growth and public and employee safety goals.[23]
- Long-Term Incentive Plan (LTIP): Qualifying officers and key NBU employees are eligible for the LTIP which comes in the form of stock, restricted stock, restricted stock units, stock options or performance shares.[24] Officers receive 35 percent of their compensation in the form of Restricted Stock Units and 65 percent in the form of Performance Shares. RSUs vest over four years if Return-on-Equity performance threshold is met while performance share awards are based on achieving ROIC threshold, three-year Cumulative Earnings-per-Share (EPS) and a modifier based on Relative Total Shareholder Return (TSR).[25] The three-year cumulative EPS as well as the Relative TSR were chosen "to align executives' interest with shareholders interest."[26]

Q. What adjustments did the Company make to its actual 2020 Base Year salaries and wages to forecast the 2023 Test Year?

A. To project its Test Year, the Company escalates its 2021-year end NBU employee salaries by 4.6 percent in 2022 and 4.35 percent in 2023. This

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23 NW Natural/800, Rogers/9-11.
24 NW Natural 10-k, Fiscal Year Ended 12/31/21, https://www.sec.gov/ix?doc=/Archives/edgar/data/1733998/000173399822000005/nwn-20211231.htm.
25 NW Natural Schedule 14A Proxy Statement, April 15, 2021, https://www.sec.gov/Archives/edgar/data/1733998/000119312521117464/d45834ddef14a.
26 *Ibid.*

includes merit increases of 4 percent and 3.75 percent with an additional 0.6 percent to reflect promotions and equity adjustments. Salary increases are also influenced by CPI Western increases of 4.5 and 3.9 percent in 2021 and 2022. Based on union contracts, bargaining unit employee salary is escalated 3.5 percent June 2021 and every June 1st thereafter until the end of the contract in 2024. Union increases include an additional 0.8 percent to account for movement throughout the training steps. Officers were escalated by the same percentages as NBUs with other updates to officer salaries who were paid below the competitive range of market data.[27]

Wages, Salaries, Overtime & FTE Recommendation

Q. What is Staff's recommendation for Test Year wages and salaries including and overtime?

A. Staff, consistent with the W&S model, starts with a Base Year (2020) that is three years prior to the Test Year, and escalates to the Test Year using All-Urban CPI (CPI) rates, which are 4.7 percent for 2021, 4.2 percent for 2022, and 2.2 percent for 2023.[28] Staff escalates BU or union salaries and wages in the same manner as the Company, applying a rate of 3.5 percent for 2021, 2022 and 2023 based on collective bargaining increases.[29]

Staff then applied the sharing principle to its and the Company's projected 2023 test year amounts. The sharing principle, which allows the Company to

[27] NW Natural/800, Rogers/5-6.
[28] Oregon Economic & Revenue Forecast March 2022, Volume XLII, No. 1, Table A.4, page 37, https://www.oregon.gov/das/OEA/Documents/forecast0322.pdf.
[29] NW Natural/800, Rogers/6.

share 50/50 the lesser of the difference between the Company's and Staff's calculated projections, or a 10 percent band around Staff's calculated projection, makes a reduction to Staff's projection. Because of the high inflation via the CPI, Staff's projection for Exempt, Non-Exempt and Union base salaries is slightly higher than the Company's, with one exception: Officer salaries. Staff has a small adjustment to Officer salaries of $28 thousand O&M and $19 thousand rate base.[30]

FIGURE 2: W&S MODEL ADJUSTMENTS

Description	Officers	Exempt	Non Exempt	Union
Actual Base Payroll (2020) calendar year	3,327,706	48,746,541	1,016,008	41,913,501
Ave. # of Employees (FTE) (2020)	10	445	14	539
Average Salary	339,903	109,600	72,452	77,825
Allowable % Increase	1.11	1.11	1.11	1.11
Ave. # of Employees (FTE) (Test Year)	10	464	15	537
Projected Payroll	3,653,037	56,653,435	1,241,068	46,331,658
Test Period Payroll	3,748,341	56,179,500	908,243	45,224,165
Total Difference for Sharing	95,304	-	-	-
10% Band - Allowable	365,304	-	-	-
50% Sharing of Lesser of Difference or Band	47,652	-	-	-
Staff Proposed Level	3,700,689	56,179,500	908,243	45,224,165
Net Payroll Adjustment	(47,652)	-	-	-

Q. Does Staff have an adjustment for Overtime?

Staff has adjustments for Union Overtime, split between $544,144 expense and $365,796 rate base. Staff calculates a $1.2 million between Staff's projection ($5.6 million) and the Company's ($6.8 million). Staff's calculation was based on the Company's union escalation rates of 3.2 percent per year.

[30] See Staff/604, Staff electronic work paper UG 435 Exhibit 604 Wage and Salary Model CONF, tab 3-year W&S.

After the sharing principle is applied, the model suggests an adjustment of half of the initial difference of $544 thousand O&M and $365 thousand rate base.[31]

FIGURE 3: OVERTIME ADJUSTMENT

Description	Officers	Exempt	Non Exempt	Union	Total
Actual Overtime (2020)	-	-	12,356	5,081,152	5,093,508
Average No. of FTE (2020)	10	445	14	539	1,007
Average Overtime per FTE	-	-	881	9,435	
Allowable % Increase	-	-	1.1150	1.1087	
Staff Proposed Level FTE for Test Period	10	464	15	537	1,026
Projected Overtime	-	-	15,093	5,616,743	5,631,836
Test Period Overtime	-	-	6,358	6,807,521	6,813,878
Total Difference	-	-	-	1,190,778	1,182,042
10% Band - Allowable	-	-	-	561,674	
50% Sharing of Lesser of Difference or Band	-	-	-	280,837	
Staff Proposed Level	-	-	6,358	5,897,580	5,903,938
Net Payroll Adjustment	-	-	-	(909,940)	(909,940)
O&M Expense as % of Payroll Exp	1	1	1	1	-
O&M Expense Adjustment - System wide	-	-	-	(544,144)	-
Oregon Allocation Factor	1	1	1	1	1
O&M Expense Adjustment - Oregon	-	-	-	(544,144)	(544,144)
Rate Base as % of Payroll Exp	0	0	0	0	1
Rate Base Adjustment - System wide	-	-	-	(365,796)	(365,796)
Rate Base Adjustment - Oregon	-	-	-	(365,796)	(365,796)

Q. Does Staff have an adjustment for FTE?

A. Staff does not have an adjustment for FTE. The Company's FTE count remained flat, never increasing over 3.5 percent since 2018 and Staff is satisfied with the Company's justification for year-over-year FTE changes.[32]

FIGURE 4: FTE

Description	2018	2019	2020	2021	TY
Total System	1,118	1,110	1,124	1,113	1,151
Oregon	998	997	1,007	992	1,026
OR % Change		-0.09%	1.02%	-1.54%	3.42%

Incentives

[31] See Staff/604, Staff electronic work paper UG 435 Exhibit 604 Wage and Salary Model CONF, tab 3-year OT.
[32] Staff/603, NWN CONF Response to Staff DR 340 (electronic spreadsheet)

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Q. What does the Company propose for employee incentives?

A. As noted earlier, the Company includes $11.5 million in incentives in its testimony[33] but only $8.5 million in its response to Staff DR 92. The discrepancy is due to Standard Data Request 92 reporting only paid cash compensation whereas the $11.5 million includes non-cash elements such as stock units.[34] Staff's count of incentives is also slightly higher at $11.7 million due to our inclusion of $174 thousand in Employee Stock Purchase Plan (ESPP) dollars.

FIGURE 5: STAFF CALCULATED INCENTIVES

Stock Expense including ESPP	**2,030,585**		Exec	NBU
RSUs	1,843,494		1,373,151	470,342
ESPP	187,092		7,035	180,057
OR Allocation	92.97%		92.97%	92.97%
OR Stock Expense/RSUs including ESPP	1,887,738		1,283,092	604,645
Total LTIP Expense	$2,554,429		2,389,777	164,652
OR Allocation	88.29%		88.29%	88.29%
OR LTIP	2,255,324		2,109,952	145,372
Short Term Incentives	8,530,912		993,207	7,537,705
OR Allocation	0.89		88.29%	0.89
Total OR Short Term Incentives	7,604,799		876,910	6,727,889
All Incentives			4,269,954	7,477,906
NW Natural Testimony			Exec	NBU
OR LTIP			2,109,952	145,372
OR RSUs			1,276,553	437,254
OR Short Term Incentive			876,910	6,727,889
Total			4,263,415	7,310,515
Difference (ESPP)			6,539	167,391

Staff thought it appropriate to include the ESPP since it was included in the Company's O&M Test Year FERC allocation summary within the total stock expense total of $2,030,585 (or $1.9 million Oregon) and specifically

[33] NW Natural/800/Rogers/17.
[34] Staff/602, Cohen/10, NWN Response to Staff DR 361.

mentioned in the Company's testimony as part of the stock expense in Operations.[35] The Test Year O&M FERC Allocation also included $2,554,429 in the Long-Term Incentive Plan in the Test Year.[36]

The total breakdown in OR allocated numbers showed $1.3 million in Stock Expense/RSUs and Employee Stock Plan for Officers and $605 thousand for NBU employees.[37] $2.1 million of Officer Long Term Incentives are also included alongside $145 thousand for NBU employees. Finally, short term incentives consist of $876 thousand for Officers and $6.7 million for NBU employees.

Q. Does Staff propose an adjustment to incentives?

A. Staff proposes excluding 100 percent of Officer incentives ($4.3 million) and half of non-Officer incentives ($3.7 million) for a total of $8 million ($4.8 million O&M and $3.2 million capital) based on the Commission's long-standing policy.[38]

FIGURE 6: INCENTIVES ADJUSTMENT

	Officers	Exempt	Non Exempt	Union	Total
Test Period Incentive	$4,269,954	$7,395,531	$82,375	$0	$11,747,860
Staff Proposed Level	$0	$3,697,766	$41,187	$0	$3,738,953
Net Payroll Adjustment	($4,269,954)	($3,697,766)	($41,187)	$0	($8,008,907)

35 Staff/602, Cohen/2, NWN Response to Staff DR 143 Attachment 1, tab O&M TY FERC Allocation Summary cell R12 (electronic spreadsheet), NW/Natural/1200/Davilla/18.
36 Staff/602, Cohen/2, NWN Response to Staff DR 143 Attachment 1, tab O&M TY FERC Allocation Summary cell S12 (electronic spreadsheet).
37 Staff/602, Cohen/4, NWN Response to Staff DR 265 Attachment 1 (electronic spreadsheet).
38 See Staff/604, Staff electronic work paper UG 435 Exhibit 604 Wage and Salary Model CONF.

The Commission's policy in disallowing 100 percent of officers' bonuses and 50 percent of non-officer bonuses is based on the conclusion these percentages of bonuses for each type of employee are typically based on increased earnings, which benefits shareholders.[39] While the Company's removal of half of its Officer Short-term incentives is a step in the right direction, its inclusion of LTIP and any portion of the Executive Annual Incentive Plan deviates from Commission policy as they are by design meant to benefit shareholders.[40]

Q. Please summarize all of Staff's adjustments to Salaries, Wages, Overtime, and Incentives.

A. Staff proposes $5.6 million of reductions to O&M and $2.6 million to Capital which includes reductions to:

- Wages & Salaries of $28 thousand O&M and $19 thousand Capital;
- Incentives of $4.8 million in O&M and $3.2 in Capital (Test Year);
- Overtime of $544 thousand in O&M and $365 thousand Capital;
- Officer Incentives in Plant of $954 thousand Capital (from 2020 and 2021); and
- Smaller adjustments to payroll taxes ($85 thousand) and depreciation ($113 thousand).[41]

39 *See PGE,* Order No. 99-033 at 62; and *US West*, Order No. 97-171 at 74-76.
40 NWN Natural Schedule 14A Proxy Statement, April 15, 2021, https://www.sec.gov/Archives/edgar/data/1733998/000119312521117464/d45834ddef14a.
41 See Staff/604, Staff electronic work paper UG 435 Exhibit 604 Wage and Salary Model CONF.

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FIGURE 7: W&S ADJUSTMENTS

Description/ Account No.	Company-Wide: Company Filing	Company-Wide: Staff	Company-Wide: O&M Adjustment	Company-Wide: Capital Adjustment	OR- Allocated: O&M Adjustment	OR- Allocated: Capital Adjustment
Wages & Salaries	$ 106,060	$ 106,013	$ (28)	$ (19)	(28)	(19)
FTE Adjustment	$ 59,880	$ 59,880	$ -	$ -	-	-
Incentives	$ 11,748	$ 3,739	$ (4,789)	$ (3,220)	(4,789)	(3,220)
Overtime	$ 6,814	$ 5,904	$ -	$ (366)	(544.14)	(365.80)
Payroll Taxes					**(85)**	
Depreciation O&M Adjustment Associated with Capital Adjustment					**(113)**	
Incentives in Plant						**954**
Total OR - Allocated Adjustments					**(5,560)**	**(2,650)**

Q. Does Staff have any further comments regarding executive compensation?

A. Staff is aware of public comments the Commission has received regarding executive compensation. Staff notes that the majority of executive compensation flows through Incentives which are 100 percent removed as per Commission policy.[42]

42 NW Natural Schedule 14A Proxy Statement, April 15, 2021, See Summary Compensation Table, https://www.sec.gov/Archives/edgar/data/1733998/000119312521117464/d45834ddef14a.

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ISSUE 2. CUSTOMER ACCOUNT, CUSTOMER SERVICE AND SALES EXPENSES

Q. Please describe customer account and customer service expenses.

A. Customer account expense is recorded in FERC accounts 901, 902, 903, 904, and 905. These accounts track expenses related to Supervision, Meter Reading, Customer Records and Collection, Uncollectibles, as well as Miscellaneous Customer Accounts. Customer Service expense is recorded in FERC accounts 907, 908, and 910 (excluding 909 Informational and Instructional Advertising Expenses, which was analyzed separately). These expenses are for Supervision, Customer Assistance, and Miscellaneous Customer Service. Uncollectibles and Advertising have been reviewed separately in Staff/200/Fjeldheim and Staff/1000/Jent. Finally, FERC accounts 911-917 are comprised of other Advertising, Demonstration and Selling, and Misc. Sales Expenses.

Q. Does the Commission Staff have a standard for how Customer Account, Customer Service and Sales expenses are treated for ratemaking purposes?

A. Rule 860-026-0020 Standards Governing Promotional Activities and Concessions mandates that all promotional activities be just, reasonable, prudent, economically feasible and beneficial to both the utility and its customers. Sales and marketing (including advertising) expenses are prohibited from being posted in customer account or customer service expenses in keeping with Order No. 99-033. Sales and Marketing Costs

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must demonstrate reasonableness and consumer benefits to be present in rates.[43]

Staff reviews expenses per appropriate use per FERC account. Staff also reviews transaction-level data to ensure expenses relate to activities such as responding to customer requests, inquiries, and safety concerns, resolving customer complaints, extending service to new customers, and providing information about safety and service issues.

FIGURE 8: CUSTOMER ACCOUNT, SERVICES AND SALES 2020-TY

FERC	FERC Category	OR -allocated 2020	OR -allocated 2021	2021-2020 % Change	OR -allocated Test Year	TY-2021 % Change
901	Supervision (of Customer Accounting and Collecting Activities)	1,730,217	1,848,583	7%	2,029,213	10%
902	Meter Reading Expenses	898,142	989,930	10%	1,083,393	9%
903	Customer Records and Collection Expenses	14,276,363	16,278,091	14%	17,329,108	6%
904	Uncollectible Accounts	687,610	881,776	28%	-	-100%
907	Supervision (Customer Service Activities)	-	-		-	
	Customer Accounts Expenses	17,592,332	19,998,380		20,441,714	
908	Customer Assistance Expenses	2,562,328	2,446,711	-5%	2,820,423	15%
909	Informational and instructional advertising expenses	2,082,809	2,758,377	32%	2,900,950	5%
910	Misc Customer Service and Information Expenses	239,215	154,485	-35%	201,346	30%
	Customer Service Expenses	4,884,352	5,359,573		5,922,720	
911	Sales Expenses Operation & Supervision	103,038	81,156	-21%	58,796	-28%
912	Demonstration and Selling Expenses	1,661,554	1,866,316	12%	2,052,618	10%
913	Advertising Expenses	428,108	556,553	30%		-100%
	Sales Expenses	2,192,700	2,504,026		2,111,413	

Q. Please describe the Company's customer account and customer service expenses in the Base Year and historically.

[43] *PGE, supra*, Order 99-033 at 63.

A. For Customer Account expenses (FERC accounts 901-905), the Company reported a Base Year Oregon allocated total of approximately $20 million, which included $13 million in labor costs.[44] When compared to 2020, most expenses have increased in the Base Year.[45] The Company attributes these increases to additional FTE and year over year increases in payroll for Supervision and Meter Reading (901-902) as well as a $2.3 million increase by payment vendor Paymentus in Customer Records (FERC 903) which is discussed in the Miscellaneous O&M section.[46] Fluctuations in Customer Service Expenses (FERC 908-910) are attributed to non-payroll expenses for postage, printing and professional services in Advertising (FERC 909) as well as a decrease due to the addition of an automated process for handling customer and supplier interactions in Misc. Customer Service (FERC 910).[47] Staff's examination of DR 153, which lists transactions from 2019-2021 confirms the above changes.

Sales Expenses & Supervision (FERC 911) saw a decrease of 21 percent, largely due to decreased payroll and overhead. Demonstration and Selling Expenses (FERC 912) recorded increases, mainly due to Professional Services, Dealer Relations, Corporate Identity and Other Contract Work. Staff audited the expenses related to professional services, dealer relations,

44 Staff/602, Cohen/5, NWN Response to Staff DR 276 Attach 1 and Attach 2 (electronic spreadsheets).
45 Staff/602, Cohen/3, NWN Response to Staff DR 153 Attach 1 (electronic spreadsheet).
46 Staff/602, Cohen/6, NWN Response to Staff DR 278.
47 Ibid.

corporate identity and other contract work. FERC account 913 is related to advertising and is covered in Staff/1000/Jent.

FIGURE 9: FERC 911 AND FERC 912 INCREASES 2020-BASE YEAR

FERC 911	Cost element name	2020	2021
	CONFERENCE TRAVEL	84	
	DUES/MEMBERSHIP		882
	EMPLOYEE AWARDS	187	125
	MEALS AND ENTERTAIN	75	24
	NON EMPLOYEE GIFTS		74
	OFFICE SUPPLIES	80	49
	P CARD UNCODED CHARG		-
	PAYROLL OVERHEAD	34,235	27,439
	SALARY BONUS PAYROLL	22	
	SALARY PAYROLL	59,130	45,371
	VACATION, SICK & HOL	9,224	7,193

FERC 912	Cost element name	2020	2021
	PROFESSIONAL SERVICE	28,169	319,508
	SALARY REGULAR	740,508	813,717
	DEALER RELATIONS	28,148	95,690
	CORPORATE IDENTITY	98,061	153,465
	OTHER CONTRACT WORK	5,620	33,227
	REBATES	41,166	65,984
	MATERIALS	297	19,994
	MATERIALS - CONS INV		4,480
	SMALL TOOLS		2,975

Q. Does Staff have any adjustments to these accounts?

A. Staff has several adjustments across FERC accounts 908 and 912, related to the Base Year increases in Corporate Identity, Dealer Relations, and Professional Services. Customer Assistance (FERC 908) Dealer Relations' expense went up over eight-fold from 2020 to the 2021 base year (from $5 thousand to $45 thousand).[48] As branding and building industry events have spurious benefits for consumers, Staff proposes the following adjustment of ($41,112) before escalation.[49]

48 Staff/602, Cohen/12, NWN Response to Staff DR 364 Attach 1 (electronic spreadsheet).
49 *Ibid.*

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FIGURE 10: ADJUSTMENT TO FERC 908 DEALER RELATIONS

Cost element name	Purchase order text	Name of offsetting account	Fiscal Year 2020	2021
DEALER RELATIONS		A/P - CONCUR		3,718
		A/P ACCRUED INV	389	(4,832)
		AIR SUPPLY INC		2,678
		BRANDING PLUS LLC	194	
		BUILDING INDUSTRY ASSOCIATION		439
		DEFD REVENUE	1,054	
		FIRST CALL HEATING AND COOLING CO	176	
		GLAVIN DEVELOPMENT LLC	4,442	
		HOME BUILDERS ASSOCIATION		8,170
		JEFFREY TAMBURRO		367
		NORTHWEST NATURAL GAS CO		1,927
		PMT PROC CASH CLEAR	(878)	
		SPADA PROPERTIES INC		248
	2021 Bolt Branding Event	GR/IR		25,036
	Parade of Homes (2021)	GR/IR		7,467
			5,377	**45,218**
		Adjustment Amount before escalation		41,112

FIGURE 11: FERC 912 CORPORATE IDENTITY, DEALER RELATIONS & PROFESSIONAL SERVICES

Sum of OR Allocated		Fiscal Year	
FERC	Cost element name	2020	2021
912	CORPORATE IDENTITY	98,061	153,465
	DEALER RELATIONS	28,148	95,690
	PROFESSIONAL SERVICE	28,169	319,508
912 Total		**154,378**	**568,664**

In Demonstration and Selling Expense (FERC 912), cost elements such as Corporate Identity, Dealer Relations and Professional Services were responsible for most of the expense increases. Corporate identity is comprised of event sponsorships, sports sponsorship, home builder association events, block parties, shopping sprees, and trade ally appreciation events with the

highest ticket items being a Timbers game and Thorns game as well as an event at the Lot at Zidell Yards.[50] Staff proposes a reduction of $153,043 thousand in base year Corporate Identity expense in FERC 912. Staff has excluded the $422 of meals and entertainment adjustments proposed in this area in Staff/1200/Rossow.

FIGURE 12: FERC 912 CORPORATE IDENTITY

Sum of OR Allocated			Fiscal Year	
FERC	Cost element name	Purchase order text	2020	2021
912	CORPORATE IDENTITY		67,033	37,132
		2020 Bolt Safety Event	7,735	
		2020 Lane Cty Home Imprv Show		4,109
		2021 Sponsorship The Lot at Zidell Yards		26,510
		Thorns 2021		19,882
		Timbers 2020 sponsorship	23,293	
		Timbers 2021		65,833
	CORPORATE IDENTITY Total		98,061	153,465
912 Total			98,061	153,465

Sum of OR Allocated				Fiscal Year
FERC	Cost element name	Document Header Text	Name	2021
912	CORPORATE IDENTITY	Kloor:May expenses	door prize for golf	49
912	CORPORATE IDENTITY	Nelson:Paul Willocks P-ca	sponsorship of coffee cart at BIA Golf Tournament	374
912 Total				422.78
			Excluding ME adjustment	153,043

Items in Dealer Relations consist of sponsorships, galas, payments to the Home Builders Associations, home tours and other related activities.[51] As ratepayers receive little benefit for these activities, Staff recommends a reduction of $92,482 after excluding the $3,207 of meals and entertainment adjustments in this area.

[50] Staff/602, Cohen/12, NWN Response to Staff DR 364 Attach 1 (electronic spreadsheet).
[51] Ibid.

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FIGURE 13: FERC 912 DEALER RELATIONS

Sum of OR Allocated			Fiscal Year	
FERC	Cost element name	Purchase order text	2020	2021
912	DEALER RELATIONS		22,401	73,121
		2021 Gala & Auction - HBF		5,744
		2021 Sponsorship The Lot at Zidell Yards		8,837
		HBA - Invoices for 2019 Sponsor/Events	5,525	
		HBA Q3 Sponsorship		5,744
		Temporary workers	223	2,245
	DEALER RELATIONS Total		28,148	95,690
912 Total			28,148	95,690

Sum of OR Allocated				Fiscal Year
FERC	Cost element name	Purchase order text	Name	2021
912	DEALER RELATIONS		Charity Contribution	44.14
			ORACCA Golf dinner	714.69
			Salem HBA Golf lunch	440.39
			Sponsorship for NARI Annual Golf Tournament	397.65
			Trade Ally appreciation	768.78
		Temporary workers	Catering salem golf	168.25
			Labor salem golf	673.61
912 Total				3,207.52

Excluding ME adjustment	92,482.67

Finally, after reviewing expenses in Professional Services in FERC 912, Staff recommends the removal of all expenses related to branding or furnace campaigns, or $262 thousand before escalation.

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FIGURE 14: FERC 912 PROFESSIONAL SERVICES

Sum of OR Allocated			Fiscal Year	
FERC	Cost element name	Purchase order text	2020	2021
912	PROFESSIONAL SERVICE		28,169	19,136
		2021 Bolt Branding Event		42,463
		2021 Fall Furnace Campaign		49,103
		2021 Fall Hearth Campaign		38,581
		2021 Summer FAU Campaign		42,079
		2021 Winter Furnace Campaign		51,981
		2021 Winter Hearth Campaign		38,342
		Addl fund needed for diff in amt needed		-
		Add'l funds for amended SOW		2,079
		Staffing Srv - Stephanie Frisch		10,773
		Staffing Srv - Stephanie Frisch continue		13,189
		Staffing Srv-Frisch August		11,488
		Temporary workers		294
	PROFESSIONAL SERVICE Total		28,169	319,508
		Adjustment before escalation		262,549

Q. What are Staff's final adjustments to Customer Assistance and Demonstration and Selling Expenses?

A. After escalating the adjustments by the All-Urban CPI for 2022 and 2023, Staff's proposal is to remove $584,841 in the Test Year from Customer Assistance Expenses (FERC 908) and Demonstration and Selling Expenses (FERC 912) as detailed below.

Q. Why does Staff propose to escalate Base Year expenses by the All-Urban CPI?

A. The Commission has a long history of relying on the All-Urban CPI and Staff uses it almost invariably to escalate costs in a general rate case. As the Commission has noted, "the All-Urban CPI measures price changes in a fixed market basket of goods and services in 200 categories, generally including

housing, apparel, transportation, medical care, recreation, education, and others to urban consumers."[52] "Local economic conditions are represented in the All-Urban CPI, as the Bureau of Labor Statistics includes prices in Oregon when it conducts its survey."[53]

[52] *Northwest Natural,* Order No. 99-697, p. 37, n10.
[53] *Ibid.*, p. 38.

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FIGURE 15: ADJUSTMENTS WITH ESCALATION

Account	Adjustments	2021	2022 CPI-U	2023 CPI-U
			4.2%	2.2%
908	Dealer Relations	41,112	42,839	43,781
912	Corporate Identity	153,043	159,471	162,979
912	Dealer Relations	92,482	96,366	98,486
912	Professional Services	262,549	273,576	279,595
			Total	584,841

ISSUE 3. MISCELLANEOUS O&M EXPENSE INCREASES

Q. Please explain the Company's individual increases to O&M.

A. The Company lists several items that were not escalated by the CPI but by expected increases in contract costs. Staff reviewed Company work papers and contracts to ensure these costs were appropriately estimated. Staff examined the following expenses:

Paymentus: An increase of $57 thousand (Oregon) due for electronic bill payment services. Accordingly, test year transactions are expected to grow by 4.5 percent annually.[54] The Company trended total payment volume based on customer growth rate as well as a bankcard usage rate of 34 percent.[55]

Locating, Inc.: An increase of $807 thousand (Oregon) based on increased prices per locate (2.25 percent in 2022 and 10 percent in 2023) as well as a 4.5 percent annual growth increase in the number of locating units.[56]

Heath Consultants: The contractual rate per foot of inspection for the survey service will increase 2 percent annually throughout the three-year contract. There is also a projected 25 percent increase in unit cost starting in 2023 due to rising labor costs. The combined effect is an increase of $223 thousand (Oregon). In addition, the Company is required to inspect its Business Districts annually per the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration. Business Districts

54 NW Natural/1200, Davilla/11.
55 Staff/602, Cohen/2, NWN Response to DR 143 Attach 1 (electronic spreadsheet).
56 Staff/602, Cohen/9, NWN Response to Staff DR 352 Attach 2 (electronic spreadsheet).

are gas mains or services where the public regularly congregates. Heath Consultants has projected an increase of $1.4 million (Oregon) related to the necessary inspections.[57]

The Company also has projected an increase of $226 thousand in severance based on a three-year average (2019-2021).[58] Finally, the Company is including $1.9 million in stock expense as well as $2.3 million of Long-Term Incentive Plan.[59] These items have been discussed in the Wages, Salary, and Incentive section.

Q. Does Staff have any adjustments in this area?

A. Staff does not have any adjustments**.**

Q. Does this conclude your testimony?

A. Yes.

[57] NW Natural/1200, Davilla/11.
[58] Staff/603, NWN CONF Response to Staff DR 356 Attach 1 (electronic spreadsheet).
[59] NW Natural/1200, Davilla/17.

CASE: UG 435
WITNESS: HEATHER COHEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 601

Witness Qualifications Statement

April 22, 2022

Staff/601
Cohen/1

Docket No: UG 435

WITNESS QUALIFICATION STATEMENT

NAME: Heather Cohen

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Utility Analyst
Energy Rates, Finance and Audit Division

ADDRESS: 201 High Street SE., Suite
100 Salem, OR. 97301

EDUCATION: Bachelor of Arts, Political Science
Fordham University, New York, NY

Master of Public Policy
American University, Washington, DC.

EXPERIENCE: I have been employed as a Senior Financial Analyst by the Oregon Public Utility Commission since January 2020 in the Energy, Rates and Finance Division. I currently perform a range of financial analysis duties related to natural gas, electric and water utilities, with a focus on operations and maintenance. I have worked on the following general rate and power cost dockets: UG 388, UG 389, UG 390, UE 374, UE 390, UE 391, UE 394 and UW 184.

I have ten years of professional level budget and fiscal analysis experience. I was previously employed as a Budget Analyst with the Oregon Department of Education (ODE), where I was the lead analyst for the Early Learning Division (ELD) which includes the federal $97M Child Care Development Fund (CCDF) and $37M Preschool Promise program. Prior to ODE, I was a Senior Financial Analyst for the state of Texas's Department of Family and Protective Services and Health and Human Services. Before that, I was a Project Manager for the University of Southern California where I directed data collection and analysis, staffing and deliverables for a $1.2M federal grant related to the provision of mental health services in Los Angeles County. Prior to USC, I was a Senior Budget Analyst for the City of New York responsible for the $1B expense budget of the Administration for Children's Services (ACS).

CASE: UG 435
WITNESS: HEATHER COHEN

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 602

Exhibits in Support Of Opening Testimony

April 22, 2022

Staff/602
Docket No: UG 435 Cohen/1

NW Natural®

Rates & Regulatory Affairs
2022 OR GRC
2022 Oregon General Rate Revision
Data Request Response

Request No.: 2022 OR GRC OPUC SDR 93

For the Test Year, please provide the breakout between O&M and rate base for all labor expense expressed as percentages. If applicable, please also provide the breakout for all labor expense between Total Company and Oregon expressed as a percentage.

Response:

Test Year labor expenses expressed as percentages:

O&M	59.8%
Capital	40.2%

Oregon Test Year labor expense represents 89.1% of Total Company labor expense.

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Docket No: UG 435

Staff/602
Cohen/2

NWN's Response to Staff Data Request 143

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Docket No: UG 435

NWN's Response to Staff Data Request 153

Is

Filed in electronic format

Docket No: UG 435

NWN's Response to Staff Data Request 265

Is

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Staff/602
Cohen/5

Docket No: UG 435

NWN's Response to Staff Data Request 276

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Docket No: UG 435

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 278

278. Company's response to DR 163 shows very large changes from 2020 – 2021 expenses in most areas of Customer Accounts and Customer Service (FERC 901-903), 909-910. Please provide an explanation for these variances.

FERC	FERC Category	System 2020	OR -allocated 2020	System 2021	OR -allocated 2021	2020 - 2021 % change
901	Supervision (of Customer Accounting and Collecting	1,960,822	1,730,217	2,094,963	1,848,583	7%
902	Meter Reading Expenses	1,017,646	898,142	1,121,648	989,930	10%
903	Customer Records and Collection Expenses	16,156,223	14,276,363	18,421,531	16,278,091	14%
907	Supervision (Customer Service Activities)	256	-		-	
908	Customer Assistance Expenses	2,916,819	2,562,328	2,785,206	2,446,711	-5%
909	Informational and instructional advertising expense:	2,360,120	2,082,809	3,125,635	2,758,377	32%
910	Misc Customer Service and Information Expenses	271,432	239,215	175,290	154,485	-35%

Response:

The Company objects to, and does not accept, the characterization in the data request that the noted changes are "very large." Notwithstanding this objection, the Company responds as follows:

FERC 901 – System year over year increase of $134k is payroll related with one additional FTE on average in 2021 as well as normal year over year increases in salaries and benefits.

FERC 902 – System year over year increase of $104k is payroll related representing normal year over year increases in salaries and benefits including more overtime and lower costs charged out of FERC 902.

FERC 903 – The system year over year increase of $2.3M is due to the additional Other Contract Work costs related to the billing and payment vendor Paymentus. Please refer to further the Company's explanation of these variances at **UG 435 OPUC DR 279**.

FERC 909 – System year over year increase of $766k included total payroll expense increase of 7% year over year and a non-payroll increase of $708k across advertising, postage, printing, and professional services. The Company incurred additional advertising and media related expense during 2021, the Base Year, in response to

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NWN Response
Page 2 of 2

increasing concerns regarding its carbon emissions, increased investments in digital advertising, as well as lower advertising and media costs in 2020 due to the pandemic. The increased advertising delivered facts about RNG supply, sources, carbon reduction benefits for customers as well as NW Natural's plan for acquiring it.

FERC 910 – System year over year decrease of $96k, related to costs incurred for the Customer Order Management ("COM") Project in 2020. This project replaced an outdated, homegrown software system encompassing order management and NW Natural's interactions and relationships with current and prospective customers and trade allies (known as a customer relationship management system, or "CRMS"). The previous, outdated system has been replaced by a streamlined, automated process for handling interactions with customers, trading partners (such as equipment suppliers), municipalities, and prospective customers. The COM project was completed and placed into service in June 2020, and therefore the related O&M costs did not recur in 2021.

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NWN's Response to Staff Data Request 344

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Docket No: UG 435

NWN's Response to Staff Data Request 352

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Staff/602
Cohen/10

Docket No: UG 435

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 361

361. Company's responses in DR 267 and DR 268 appear to be contradictory and are provided below for ease of reference. Please reconcile and explain whether there is or is not consistency between these two responses and refile the Company's response to either of these data requests as appropriate.

Request No.: UG 435 OPUC DR 267

267. The Company seeks full recovery of long-term incentives for Officers and employees which include restricted stock units (RSUs) and Performance Shares, is this correct?
a. Please breakdown the dollar amounts tied to long-term incentives, separately for Officers, Exempt and Non-exempt.
b. Please breakdown the dollar amounts of RSUs and Performance Shares within long-term incentives, separately for Officers, Exempt and Non-exempt.

Response:

Correct. The Company is seeking full recovery of long-term incentives for Officers and employees which does include restricted stock units (RSUs) and Performance Shares (Long Term Incentive Compensation).

See UG 435 OPUC DR 265 Attachment 1, tab DR 267 269 for breakdown of both RSU and LTIP by Officers, Exempt and Non-exempt.

Request No.: UG 435 OPUC DR 268

268. Please reconcile the amounts in question 4 parts a and b with Exempt and Non-Exempt amounts of $6,641,122 and $73,972 in the Test Year and $6,737,316 and $74,084 in the Base Year) in DR 92.

Response:

UG 435 SDR 92 includes incentive or bonus cash paid or expected to be paid to employees for short-term incentives. RSUs and Performance Shares are long-term incentives and therefore were not included in UG 435 SDR 92.

Response:

The Company's responses in DR 267 and DR 268 are not contradictory or inconsistent with each other. UG 435 OPUC SDR 92 which is being referenced in UG 435 OPUC

Staff/602
Docket No: UG 435 Cohen/11

DR 268 asks specifically to include “actual paid cash compensation” and, as such, is interpreted by the Company to exclude incentive compensation that is awarded not as cash but as stock units. This is in line with how the Company has historically answered SDR 92.

Request No.: 2022 OR GRC OPUC SDR 92
For the Test Year and the preceding 4 calendar years, please provide (on a Total Company basis), a summary table (using the categories and format shown below) that includes the number of FTE’s (exclude FTEs created by overtime hours) and the actual paid cash compensation broken down between base wages or salaries, overtime, and incentives or bonuses. For any calendar year included in this request for which actual data is not available for the entire calendar year, please create a calendar year using the available actual data combined with the forecast applicable to the rest of the year. Please note which months and figures are associated with both the actual and forecast data.

Docket No: UG 435

Staff/602
Cohen/12

NWN's Response to Staff Data Request 364

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PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 603

IS CONFIDENTIAL AND SUBJECT TO

PROTECTIVE ORDER NO. 21-461

(Electronic format)

Exhibits in Support
of Opening Testimony

April 22, 2022

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 604

IS CONFIDENTIAL AND SUBJECT TO

PROTECTIVE ORDER NO. 21-461

(Electronic format)

Exhibits in Support
of Opening Testimony

April 22, 2022

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Melinda B. Rogers

COMPENSATION & BENEFITS EXHIBIT 3102

June 4, 2024

Wages, Salary, and Overtime

Q. Please explain how Staff used the Three-Year W&S model to arrive at its recommendation for wage and salary levels for the Test Year.

A. As previously stated, PGE escalated its Base Year 2022 non-union and union wages and salaries by four percent for 2023 and 2024.[25] Staff, consistent with the W&S model, starts with a Base Year that is three years prior to the Test Year (2021), and escalates to the Test Year using All-Urban CPI (CPI) rates, which are 8.0 percent for 2022, 3.9 percent for 2023, and 2.2 percent for 2024.[26] Staff escalated union salaries and wages in the same manner as the Company, applying a rate of 7.0 percent for 2022 and 4.0 percent for 2023 and 2024 based on expected collective bargaining increases.[27]

Staff then applied the sharing principle to its and the Company's projected 2024 test year amounts. The sharing principle, which allows the Company to share 50/50 the lesser of the difference between the Company's and Staff's calculated projections, or a 10 percent band around Staff's calculated projection, results in a reduction to Staff's projection.

Q. What is Staff's recommendation for Test Year wages and salary, including overtime?

A. Based on application of the Three-Year Wages and Salary Model, Staff proposes the following adjustments to PGE's proposed wages and salaries levels: ($52 thousand) to Officer salaries, ($110,000) to Exempt salaries, and

[25] PGE/500, Mersereau – Neitzke/19.
[26] Oregon Economic & Revenue Forecast March 2023, Volume XLIII, No. 1, Table A.4, page 44.
[27] Staff/1301, PGE response to Staff DR 94 (pdf) and 95 (pdf).

($1.26 million) to non-Exempt salaries. This results in an overall adjustment of ($1.43 million). Lastly, Staff made no adjustments to union salaries or overtime since the Company's filed proposal was less than Staff's calculation.[28]

FIGURE 3. W&S MODEL ADJUSTMENTS

Description	Officers	Exempt	Non Exempt	Union	Total
Actual Base Payroll (2021) calendar year	$4,793,841	$196,141,176	$23,765,080	$67,081,985	$291,782,082
Ave. # of Employees (FTE) (2021)	11	1675	404	630	2719
Average Salary	$ 443,874	$ 117,127	$ 58,825	$ 106,564	
Allowable % Increase	1.14680664	1.14680664	1.14680664	1.157312	
Ave. # of Employees (FTE) (Test Year)	10	1881	435	680	3006
Projected Payroll	**$5,090,379**	**$252,660,154**	**$29,345,242**	**$83,862,823**	**$370,958,597**
Test Period Payroll	**$5,193,708**	**$252,881,730**	**$31,870,957**	**$80,991,764**	**$370,938,159**
Total Difference for Sharing	$ 103,329	$ 221,576	$ 2,525,715	$ -	
10% Band - Allowable	$ 509,038	$ 25,266,015	$ 2,934,524	$ -	
50% Sharing of Lesser of Difference or Band	$ 51,665	$ 110,788	$ 1,262,857	$ -	
Staff Proposed Level	**$5,142,043**	**$252,770,942**	**$30,608,100**	**$80,991,764**	**$369,512,849**
Net Payroll Adjustment	$ (51,665)	$ (110,788)	$ (1,262,857)	$ -	**$ (1,425,310)**

Incentives[29]

Q. What does PGE propose for employee incentives?

A. For non-Officer incentives, PGE includes $20.3 million in the Test Year. PGE testifies that it removed 50 percent of its budgeted Non-Officer Incentives to be consistent with the Commission's policy regarding incentives and 100 percent of officer incentives.

Q. Does Staff agree with PGE's removal of 50 percent of non-Officer Incentives?

[28] See Staff/1303, Staff electronic work paper, UE 416 Exhibit 1303 Wage and Salary Model CONF.xlsx, tab PUC 3-year W&S. Historically, the adjustments from Staff's model have been public/non-confidential but the model itself is published as confidential.

[29] See Staff/1301, PGE Response to Staff DR 255 attachment A (electronic spreadsheet) provides underlying data for incentives and Response to DR 256 Attachment A (electronic spreadsheet), which provides the information on total aggregate labor costs by division.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Reply Testimony of Cory A. Beck

CUSTOMER COMMUNICATIONS EXHIBIT 3200

June 4, 2024

EXHIBIT 3200 - REPLY TESTIMONY - CUSTOMER COMMUNICATIONS

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I. INTRODUCTION AND SUMMARY

Q. Are you the same Cory Beck who filed Direct Testimony in this proceeding on behalf of Northwest Natural Gas Company dba NW Natural ("NW Natural" or the "Company")?

A. Yes, I presented NW Natural/1100, Beck.

Q. What is the purpose of your Reply Testimony in this proceeding?

A. The purpose of my Reply Testimony is to respond to the Opening Testimony of Paul Rossow on behalf of Staff for the Public Utility Commission of Oregon ("Commission"), as well as the Opening Testimony of Nora Apter of the Oregon Environmental Council and Meredith Connolly of Climate Solutions on behalf of the Coalition,[1] concerning NW Natural's customer communications (or advertising)[2] expenses for the Test Year (November 2024 through October 2025). I will also respond to the testimony of Charity Fain (Community Energy Project), Anahi Segovia Rodriguez (Verde), and Nikita Daryanani (Coalition of Communities of Color) on behalf of the Coalition regarding the advertising for the Company's bill discount program and investment in multilingual outreach.

Q. Please summarize your Reply Testimony.

A. In my testimony, I:

[1] The Coalition includes the Coalition of Communities of Color, Climate Solutions, Verde, Columbia Riverkeeper, Oregon Environmental Council, Community Energy Project, and Sierra Club.

[2] NW Natural uses the term "customer communications," while other parties use the term "advertising." NW Natural understands these terms to be referring to the same category of expense. These terms are used interchangeably throughout this testimony.

- Provide relevant background regarding Category A and B customer communications expense;
- Respond to Staff's and the Coalition's recommended adjustments to NW Natural's proposed Test Year Category A advertising expense;
- Respond to Staff's and the Coalition's recommended adjustments to NW Natural's proposed Test Year Category B advertising expense;
- Respond to the Coalition's testimony regarding the Company's marketing of the bill discount program and investment in multi-lingual outreach.

Q. Do you include any exhibits with your testimony?

A. Yes, I am presenting the following exhibits:

- NW Natural/3201, Beck (Coalition's response to UG 490 NWN to Coalition DR 20).
- NW Natural/3202, Beck (Company's response to UG 490 OPUC DR 337).

II. BACKGROUND REGARDING CUSTOMER COMMUNICATIONS EXPENSE

Q. What are expenses for Category A communications?

A. Category A expenses are energy efficiency or conservation advertising expenses that do not relate to a Commission-approved program, utility service advertising expenses, and utility information advertising expenses.[3] Under OAR 860-026-0022(3)(a), expenditures for Category A advertising up to 0.125 percent of gross retail operating revenues are presumed just and reasonable. As I explained in my Direct Testimony, in NW Natural's case, that percentage results in $1,354,530 for

[3] OAR 860-026-0022(2)(a).

Category A communications based on forecasted revenues and customer count, which is equivalent to about $1.92 per customer.[4]

Q. Did NW Natural request more than the amount of Category A expense presumed reasonable for the Test Year?

A. Yes, by 3 cents per customer. The Company is requesting $1.95 per customer, $0.03 higher than the customer rate derived using the level presumed just and reasonable under OAR 860-026-0022(3)(a). The threshold in OAR 860-026-0022(4) sets an amount that is presumed reasonable but allows for more to be recovered as long as support is provided, and the Commission approves it.[5] The Company's proposed Category A request for cost recovery amounts to approximately $1.95 per customer, which is very close to the $1.92 customer rate presumed just and reasonable under OAR 860-026-0022(3)(a) and is justified in order for the Company to effectively deliver its current level of Category A communications on topics outlined in my Direct Testimony and includes a minimal increase ($0.03 per customer) to account for producing a bill insert to educate customers about the new climate policy changes that could impact customer bills beginning during the Test Year.

[4] NW Natural/1100, Beck/2.

[5] "The presumptions in section (3) of this rule are rebuttable. An energy or large telecommunications utility seeking to include expenditures in excess of amounts in section (3) of this rule shall have the burden of showing that the expenditures are just and reasonable. Parties challenging expenditures which are equal to or less than the amounts in section (3) of this rule have the burden of showing that the expenditures are not just and reasonable."

Q. What are Category B customer communications?

A. Category B communications are safety-related communications, and include legally mandated messages intended to ensure that NW Natural's customers, contractors, public officials, emergency officials, and the general public within the NW Natural service territory know how to use natural gas safely, have emergency preparedness awareness (for example, being prepared in the event of an earthquake), know how to recognize, react, and respond to a potential leak or safety issue related to natural gas, and know how to prevent damages to underground utility pipelines.[6] The Company develops its Category B communications through its Public Safety Awareness Program. The Program is regularly inspected by the OPUC. Under OAR 860-026-0022(3)(b), Category B communications are presumed to be just and reasonable for ratemaking purposes. NW Natural requested $975,000 for the Category B customer communications for the Test Year.[7]

Q. Does the Company's Test Year include any other expenses for Categories C, D, or E customer communications?

A. No. As I explained in my Direct Testimony,[8] NW Natural is not seeking rate recovery of any expenses in Category C (corporate imaging),[9] Category D

[6] OAR 860-026-0022(2)(b) ("Category 'B' - Legally mandated advertising expenses"). "Legally mandated advertising expenses" means advertising expenses, the primary purpose of which is to comply with (A) local, state, or federal statutes, ordinances, rules, or regulations; and (B) court or commissions orders. OAR 860-026-0022(1)(d).

[7] NW Natural/1100, Beck/6.

[8] NW Natural/1100, Beck/2.

[9] OAR 860-026-0022(2)(c) ("Category 'C' - Institutional advertising expenses, promotional advertising expenses and any other advertising expenses not fitting into Category 'A,' 'B,' or 'D'").

(political/non-utility advertising),[10] or Category E (energy efficiency/conservation advertising related to a program approved by the Commission).[11]

III. CATEGORY A CUSTOMER COMMUNICATIONS EXPENSE

A. Staff's Recommendations

Q. What were the results of Staff's review of NW Natural's proposed Category A customer communication expense?

A. Staff confirmed that the customer communications identified by NW Natural under the Category A customer communication expense were related to energy efficiency, safety, and conservation.[12]

Q. What is Staff's recommendation regarding Category A customer communications expense?

A. Staff recommends limiting the Company's recovery of Category A expense to the amount that is presumed reasonable under OAR 860-026-0022(3)(a), which is $1,354,530 or $1.92 per customer.[13]

Q. What is NW Natural's response to Staff's recommendation for the Category A customer communications expense?

A. NW Natural continues to support the Company's proposed Category A request for cost recovery for the Test Year—approximately $1.95 per customer—as justified

[10] OAR 860-026-0022(2)(d) ("Category 'D' - Political advertising expenses and nonutility advertising expenses").

[11] OAR 860-026-0022(2)(e) ("Category 'E' - Energy efficiency or conservation advertising expenses that relate to a Commission-approved program[]").

[12] Staff/1700, Rossow/7.

[13] Staff/1700, Rossow/8.

and reasonable because it is very close to the amount considered reasonable in accordance with the Commission's rules and allows for the expense for production of a bill insert to educate customers and properly inform them about the new climate policy changes that could affect customers beginning during the Test Year.

The Company took seriously the Commission's direction in Order No. 22-388 to carefully scrutinize its Category A advertising expense, and to remove expense that the Commission deemed promotional in nature, and did so in this case. Thus, even though the advertising expense is slightly above the Commission's threshold, it represents advertising connected with core utility service and does not include any promotional advertising, and therefore should be recoverable in rates.

Q. How does NW Natural's Category A request compare to the amounts presumed reasonable for other utilities?

A. The revenue-based formula applicable to all energy utilities results in natural gas utilities having far less Category A expense presumed reasonable as compared to electric utilities. NW Natural should be allowed rate recovery for communications that are generally in line with electric utilities in Oregon on a per customer basis. NW Natural's request for $1.95 per customer is far less than electric utilities that serve most of the same customers as well. For example, based on 2022 data, Table 1 below shows that the revenue-based formula translates into an allowance of $2.56 per customer for PacifiCorp and $2.91 per customer for Portland General Electric Company compared to $1.52 per customer for NW Natural. This funding gap is inappropriate, given NW Natural's communication topics are not unique from

an electric utility. Additionally, NW Natural has an expansive Oregon service territory, which includes the Oregon coast from Astoria to Coos Bay, the Willamette Valley from Portland to Eugene, and the Columbia River Gorge.

TABLE 1

2022 Category A per Customer Based on Operating Revenue

	Year	Operating Revenue	CAT A - 0.125%	# of Customers	CAT A per Customer
NW Natural	2022	847,407,441	1,059,259	694,830	1.52
PGE	2022	2,145,143,572	2,681,429	922,444	2.91
Pacificorp	2022	1,264,763,577	1,580,954	616,834	2.56

Source of Revenues and Customers - OPUC Oregon Utility Statistics 2022

B. The Coalition's Recommendations

Q. What is the Coalition's recommendation regarding Category A customer communications expense?

A. The Coalition recommends seeking a disallowance of $310,641 from the Company's Category A customer communications expense, arguing that NW Natural is improperly including Category C (corporate imaging) or Category D (political/non-utility advertising) in its Category A customer communications expense.[14]

[14] Coalition/200, Apter-Connolly/36-37.

Q. Why does the Coalition claim that the Company's Category A customer communications expense includes Category C and Category D customer communications?

A. It appears that the Coalition's argument is rooted in its belief that any customer communications regarding NW Natural's utility service, by the very nature of the Company being a gas utility, contain "implied political agenda to influence ratepayers and promote the continued use of gas" and therefore cannot be designated as Category A customer communications expense.[15] Thus even though the communications may have the primary purpose of informing customers of the Company's energy efficiency or conservation programs, or utility information such as rate increases, environmental impacts, or other contemporary items of customer interest, because they suggest that NW Natural will continue to provide natural gas services in the future, the Coalition would argue they are political or promotional in nature.

Q. How does NW Natural respond to the Coalition's underlying claim?

A. While I am not a lawyer, it is my understanding that when the Commission reviews customer communication expenses to ensure compliance with the requirements of OAR 860-026-0022, the Commission looks to the primary purpose of the advertisement by considering the context of the publication.[16] I disagree with the Coalition's underlying claim that would attach an implied political or promotional

[15] Coalition/200, Apter-Connolly/35.

[16] *In re Revised Tariff Schedules Filed by Nw. Nat. Gas Co. for a Gen. Rate Increase*, Docket No. UG 81, Order No. 89-1372 (Oct. 18, 1989) ("The advertising rule defines advertisements according to their primary purpose.").

motivation as it seems contrary to the inquiry of the primary purpose of the customer communications. As such, the Commission should reject the Coalition's proposed adjustment for Category A communications expense.

Q. What are the major topics covered in the Coalition's testimony regarding Category A customer communications?

A. The Coalition specifically addresses six topics in its testimony regarding Category A customer communications: (1) the Company's "Comfort Zone" newsletters; (2) customer communications regarding the Company's community service activities; (3) customer communications regarding gas appliances; (4) customer communications regarding the Company's Smart Energy Program; (5) customer communications regarding conservation efforts, greenhouse gas ("GHG") emissions data, factual information regarding electrification, and the status of Oregon's invalidated Climate Protection Program ("CPP") and future greenhouse gas regulations; and (6) rate impact information as a result of climate change policies.

1. <u>"Comfort Zone" Newsletters</u>

Q. Please describe the Company's "Comfort Zone" newsletters.

A. The Company's "Comfort Zone" newsletters are typically published five to six times per year and inserted into customer bills. The Company also issues an electronic newsletter that is emailed to Paperless Billing Customers each month. In 2023, the Company published 5 such printed newsletters and 12 electronic newsletters. Typically, the primary purpose of the "Comfort Zone" newsletters is to provide utility billing, payment programs, and energy efficiency information to customers, along

with other messages that may be of interest to customers and to assist them in understanding complex issues and services for one of their essential energy providers. Accordingly, where such information is identified in the newsletters, it is recorded to the Category A customer communications expense.

Q. Did NW Natural identify different categories of customer communications in the "Comfort Zone" newsletters?

A. Yes. In response to feedback received in the last rate case, docket UG 435, my department carefully reviewed the content of the "Comfort Zone" newsletters to ensure that the messages are being recorded to the appropriate cost center (Category A, Category B, Category C). The Company noted Category C customer communications and allocated about 25 percent of the total cost for the printed "Comfort Zone" newsletters to the Category C customer communications cost center.

Q. What concerns does the Coalition raise regarding the "Comfort Zone" newsletters?

A. The Coalition claims that "many advertisements the company billed as Category A or B advertising are either promotional, political or nonutility advertising."[17]

[17] Coalition/200, Apter-Connolly/44.

Q. Does the Coalition provide particular examples of the "Comfort Zone" newsletters that it believes are promotional, political, or represent nonutility advertising?

A. Yes. The Coalition points to "Comfort Zone" newsletters/e-newsletters containing information regarding community service activities, natural gas appliances, the Company's Smart Energy Program, and information about Oregon's invalidated and future greenhouse gas regulations.[18] I will respond to these topics in the relevant sections below.

Q. Why is communicating about community service activities, natural gas appliances, the Company's Smart Energy Program and information about Oregon's invalidated and future greenhouse gas regulations relevant for Category A communications?

A. NW Natural understands that customer satisfaction is a critical aspect for measuring the success of the services and information we provide. Customer satisfaction measures the overall customer experience to gauge if we are meeting customer expectations.

Q. How has NW Natural performed in providing excellent customer satisfaction to its customers?

A. One method how NW Natural measures customer satisfaction is through a third – party study conducted by J.D. Power and Associates. Now in its 22nd year, the J.D. Power study measures residential customer satisfaction with natural gas

[18] Coalition/200, Apter-Connolly/44-51.

utilities across six factors: safety and reliability, customer care, billing and payment, price, corporate citizenship, and communications. The 2023 results are based on more than 60,000 responses from residential customers of the 85 largest gas utilities across the United States, which represent more than 64.6 million households. The study was conducted from January 2023 through October 2023. NW Natural scored second highest in customer satisfaction among large utilities (500,000 or more customers) in the Western United States, according to J.D. Power's Gas Utility Residential Customer Satisfaction Study. This is the 20th time NW Natural has scored in the top two in the West; 2023 survey results placed the Company in the top-10 nationally, as well. In addition, NW Natural finished first among West peers in the customer satisfaction categories for safety and reliability, price, and corporate citizenship.

Q. What J.D. Power questions that measure customer satisfaction are directly linked to the Company's communications regarding high-efficiency natural gas appliances, Oregon's invalidated and future greenhouse gas regulations, the Smart Energy Program, and community service activities?

A. The J.D. Power study involves survey questions addressing the following topics:

- Efforts to communicate changes that affect account/service, which may implicate Oregon's invalidated and future greenhouse gas regulations;
- Usefulness of suggestions to reduce usage/lower bills, which relates to the Company's messaging regarding high-efficiency natural gas appliances;
- Actions to take care of the environment, which would include the Company's Smart Energy Program;

- Involvement in the community, which is addressed by the Company's community service activities.

Q. Why is NW Natural communicating with its customers regarding its community service activities?

A. NW Natural understands that overall customer experience and satisfaction is critical to meeting customer expectations. Providing information concerning Company involvement and informing and educating customers about the Company's community service activities and offering customers opportunities for engagement is necessary to meet customer expectations of their utility.

Q. Please explain why NW Natural considers customer communications regarding its community service activities as appropriate for cost recovery as a Category A expense.

A. Under OAR 860-026-0022(2)(a), "Category A" advertising expenses include (among others) utility information advertising expenses. In turn, "utility information advertising expenses," are defined as:

> advertising expenses, the primary purpose of which is to increase customer understanding of utility systems and the function of those systems, and to discuss generation and transmission methods, utility expenses, rate structures, rate increases, load forecasting, environmental considerations, and other contemporary items of customer interest[.][19]

The Company's community service activities and corporate responsibility efforts are a contemporary item of customer interest, and it is appropriate to provide information to customers about the Company's community engagement.

[19] OAR 860-026-0022(1)(g).

Q. What are the Coalition's criticisms of the Company's customer communications regarding community service activities?

A. The Coalition claims that customer communications describing NW Natural's community service activities and opportunities for engagement and support are unrelated to utility service and are not calculated to improve ratepayers' understanding of utility systems. Instead, the Coalition argues that these customer communications are either corporate imaging institutional advertising (Category C) or nonutility related (Category D) advertising.[20]

Q. How do you respond to the Coalition's claims that the Company's customer communications regarding community service activities is promotional/institutional in nature because it is intended to promote the Company's brand rather than inform customers?

A. I disagree with the assertion that the Company's customer communications discussing community service are primarily promotional/institutional in nature. The Company works diligently to provide information to customers that meets customer expectations. The Company understands that its customers are concerned about community engagement, which includes corporate responsibility efforts and community service activities, such as the Gas Assistance Program ("GAP").[21] It is clear from the examples chosen by the Coalition (specifically shown in Figures 1 through 4 in my Reply Testimony, below), that the primary purpose of the

[20] Coalition/200, Apter-Connolly/44-46.

[21] Coalition/245, Apter-Connolly/32 (NW Natural Response to UG 490 Coalition DR 117 Attachment 2 (32 of 53)).

messages is to inform and educate customers about NW Natural's corporate responsibility efforts and community engagement activities, including donations to, partnerships with, and recognition from community organizations and programs, as well as to provide customers the opportunity to support the Company's community-focused programs. All messages aid in providing customers information they expect to receive.

Q. By contrast, what is Category C institutional and promotional advertising?

A. Institutional advertising is not primarily designed to convey information, but rather is designed to enhance the credibility, reputation, character, or image of an entity or institution.[22] Promotional advertising is designed to aid in the retention of customers and attract new customers by promoting the cost and performance benefits of natural gas and a variety of natural gas products.[23] NW Natural specifically excluded promotional/institutional advertising—or Category C communications—from its request for cost recovery.

Q. The Coalition also asserts that the Company's internal strategy documents admit that the purpose of communicating information regarding public service activities is to improve corporate image.[24] Is this true?

A. No. I reviewed the materials referenced by the Coalition, and although they describe the Company's communication strategy and community engagement activities, the strategies are clearly identified as a customer service message area

[22] OAR 860-026-0022(1)(c).

[23] OAR 860-026-0022(1)(c); OAR 860-026-0010.

[24] Coalition/200, Apter-Connolly/45.

of focus and does not include any linkage with promotional advertising. The strategy is high-level to guide direction for development of messages. The Company reviews all messages that are produced for the appropriate charge category. If a message is Category C in nature, it will be charged to a Category C account.

Q. How do you respond to the Coalition's claims that the Company's customer communications regarding community service activities is non-utility related information?

A. I disagree with the assertion that the Company's customer communications discussing community service is non-utility related information. As discussed above, the Company understands that its customers are concerned about community engagement and support, which includes corporate responsibility efforts and community service activities. The primary purpose of the messages noted by the Coalition, which I will discuss in further detail below, is not to provide information about or encourage the purchase of products or services that fall outside the rate of return regulation.

Q. Can you explain non-utility advertising?

A. Non-utility advertising is communication, "the primary purpose of which is to provide information about or encourage purchase of products or services whose revenues fall outside the scope of rate of return regulation by a state or federal

regulatory body[.]"[25] NW Natural specifically excluded non-utility information advertising—or Category D communications—from its request for cost recovery.

Q. How do you respond to the Coalition's claim that informing customers about the community service activities of NW Natural's employees is promotional, institutional, or non-utility related advertising?[26]

A. I disagree that the primary purpose of customer communications regarding the community engagement of NW Natural's employees is to promote the Company's brand or otherwise does not provide useful utility information. An example of one of the messages referenced by the Coalition[27] recognizes a NW Natural employee's work on the Board of Trustees of the Oregon Historical Society, work on the Board of Directors of the nonprofit OnPoint Community Credit Union, and pro bono financial-planning services.

NW Natural encourages its employees to constructively engage in the community and contribute to the Company's corporate responsibility, a contemporary item of interest to our customers. The primary purpose of this message is to provide useful information to customers about the community engagement of NW Natural's employees and to inform customers about possible additional avenues of intersection with the Company and outside community organizations.

[25] OAR 860-026-0022(1)(i).

[26] Coalition/200, Apter-Connolly/44.

[27] Coalition/216, Apter-Connolly/8.

Q. How do you respond to the Coalition's claim that informing customers about opportunities to contribute to the GAP is promotional, institutional, or nonutility related advertising?[28]

A. I disagree that the primary purpose of customer communications providing information regarding the GAP and offering customers the opportunity to voluntarily contribute to the program (e.g., Figure 1) is to promote the Company's brand or otherwise does not provide useful utility information.

Figure 1. Example of GAP Communications.

GAP is wholly incremental above other low-income energy assistance programs and is funded by voluntary contributions from customers, employees, and occasionally by private grants.[29] NW Natural also contributes shareholder dollars to the program annually from its Corporate Philanthropy fund.[30] Offering customers information regarding the low-income GAP and informing customers

[28] Coalition/200, Apter-Connolly/45.

[29] Coalition/223, Apter-Connolly/1.

[30] Coalition/223, Apter-Connolly/1.

about how to voluntarily contribute to and/or support such energy assistance programs for customers in need is pertinent utility information and does not implicate promotional/institutional advertising.

Q. The Coalition seems to imply that charging the GAP customer communications to Category A customer communication expense is contrary to the Company's assertion that NW Natural shareholders (not customers) cover "all the program delivery and administrative costs so that every dollar goes to GAP recipients."[31] Is the Coalition correct?

A. No. GAP delivery expenses and administrative costs are separate and distinct from NW Natural's customer outreach regarding the GAP program and solicitation of voluntary customer contributions. GAP delivery costs are allowable costs incurred for implementing and carrying out eligible GAP activities and cover the costs of employees directly carrying out program activities, including employee salaries and fringe benefits that are necessary for successful completion of the program activities. Administrative costs are costs for staff-time and overhead costs for planning and general administration of the program. GAP administrative costs cover the cost of planning, general management, oversight, coordination, in addition to equipment, general office supplies, travel/mileage and implementation costs of the GAP program as a whole. It is these costs that go to the actual implementation of the GAP that are fully covered by NW Natural shareholders (not customers).

[31] Coalition/200, Apter-Connolly/45; Coalition/223, Apter-Connolly/1.

Q. How do you respond to the Coalition's claim that newsletter communications to customers regarding the Company's donations to community organizations, partnerships with community organizations, and announcements about education scholarship programs are primarily promotional, institutional, or nonutility related advertising?[32]

A. I disagree that the primary purpose of customer communications providing information regarding the Company's donations to community organizations, partnerships with community organizations, and announcements about education scholarship programs is promotional/institutional or otherwise nonutility related information. An example of one of the newsletter messages referenced by the Coalition (shown below in Figure 2) provides information about the Company's partnership with Here is Oregon to feature the work of nonprofit Adelante Mujeres (Women Rise Up) at the Fiesta of Hope event.

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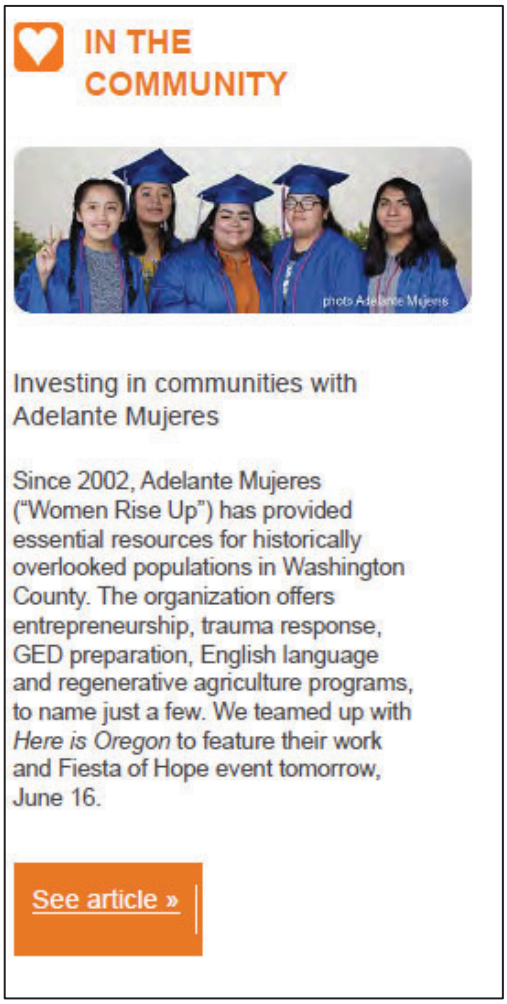
[32] Coalition/200, Apter-Connolly/45.

Figure 2. Example of Company Community Service Communications.



The primary purpose of this message is to provide useful information to customers about the community engagement of NW Natural and to inform customers about possible additional avenues of intersection with the Company and outside community organizations.

Q. How do you respond to the Coalition's claim that customer communications regarding third-party recognition of NW Natural's corporate responsibility, ethics, and compliance practices are primarily promotional, institutional, or nonutility related advertising?[33]

A. I disagree that the primary purpose of customer communications providing information regarding third-party recognition of NW Natural's corporate responsibility, ethics, and compliance practices is to promote the Company's brand or otherwise does not provide useful utility information. The message specifically referenced by the Coalition (shown below in Figure 3) informs customers regarding NW Natural's recognition by Ethisphere in its World's Most Ethical Companies list.

Figure 3. Example of Company Corporate Responsibility Recognition Communications.

The Company understands that its customers are concerned about community engagement, and to this end, informing customers about third-party recognition of the Company's ethical and compliance practices is directly related to this customer item of interest.

[33] Coalition/200, Apter-Connolly/45.

2. Gas Appliances

Q. What concerns does the Coalition raise regarding the Company's customer communications concerning rebates on gas appliances?

A. The Coalition argues that NW Natural improperly included numerous "Comfort Zone" newsletters, bill inserts, on hold messages, and emails and e-newsletters promoting the purchase of gas appliances in its Category A customer communication expense, which should be designated as Category C promotional advertising.[34] For convenience, examples of the messages specifically referenced by the Coalition are copied below in Figure 4 through Figure 8.

Figure 4. "Comfort Zone" Example of Gas Appliance Utility Information / Service Communication

[34] Coalition/200, Apter-Connolly/46-49.

Figure 5. "Comfort Zone" Example of Gas Appliance Energy Efficiency Communication

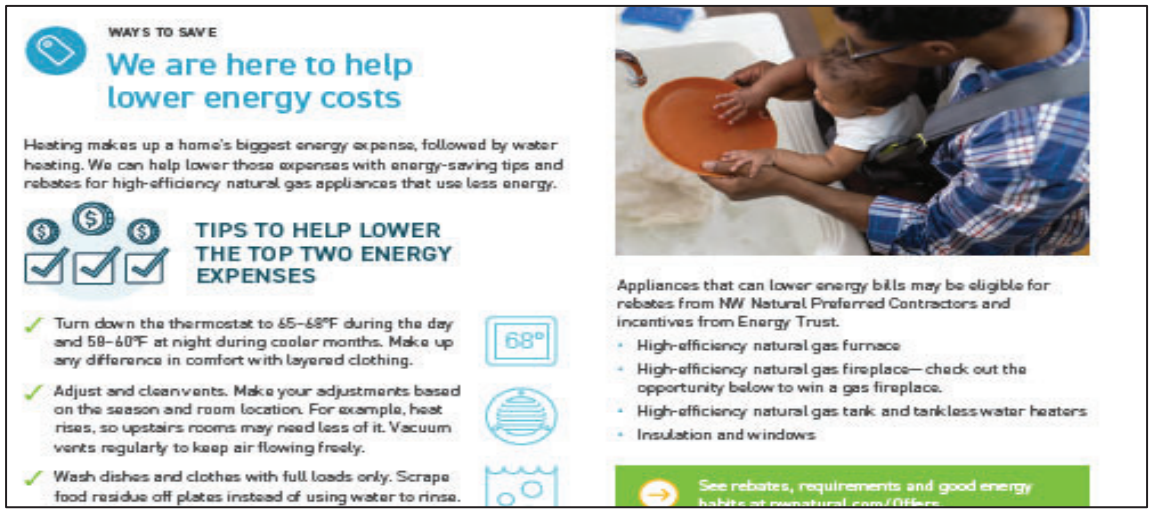


Figure 6. "Comfort Zone" Example of Gas Appliance Energy Efficiency Communication

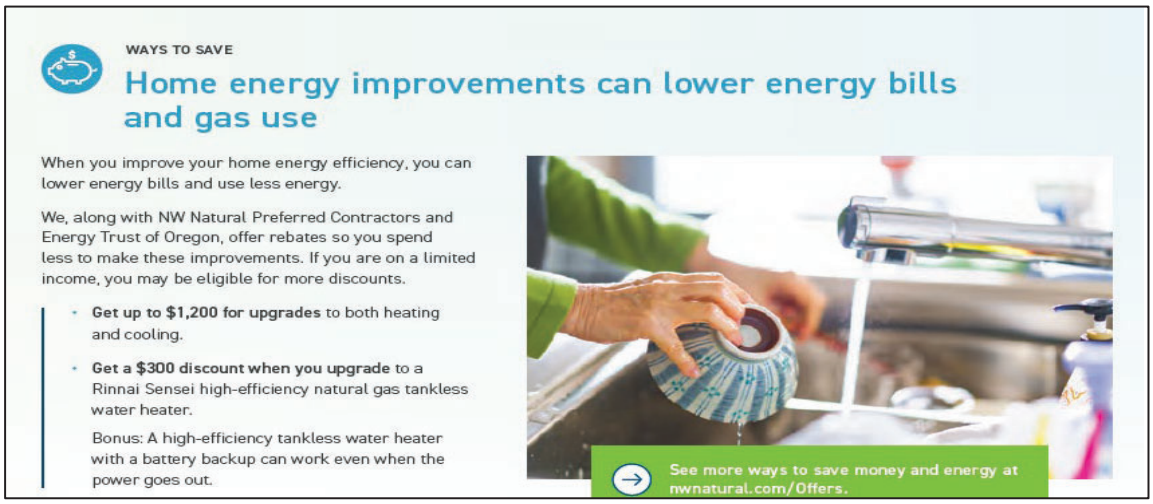


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Figure 7. Bill Insert Example of Gas Appliance Energy Efficiency Communication

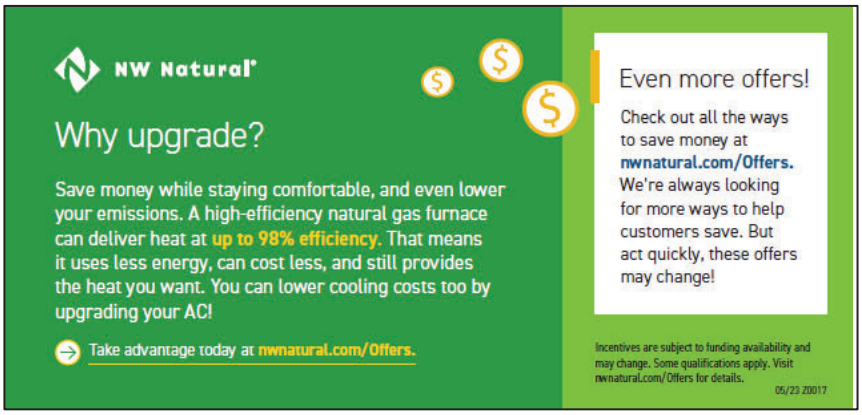
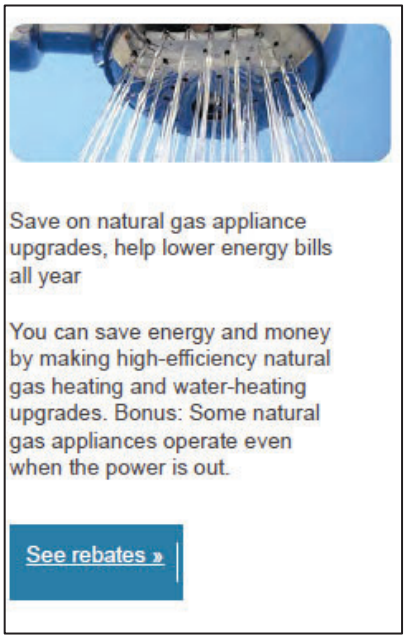


Figure 8. e-Newsletter Example of Gas Appliance Energy Efficiency Communication



Q. How do you respond to the Coalition's arguments regarding the Company's customer communications expense associated with natural gas appliances?

A. As discussed above, Category A customer communication expense includes energy efficiency or conservation advertising expenses that do not relate to a Commission-approved program, utility service advertising expenses, and utility

information advertising expense. The primary purpose of the messages referenced by the Coalition, including the examples in Figure 4 through Figure 8 above, are not promotional; rather, the primary purpose of the messages is to inform customers about high efficiency appliances, lowering gas consumption and energy usage, costs, and emissions. The customer communications in Figure 5 through Figure 8 above squarely fit under energy efficiency and conservation advertising expenses included in Category A. Figure 5 through Figure 8 also strongly focus on environmental considerations, which are included under utility information advertising expenses, and "encourage efficient and safe use of utility services," which is included under utility service advertising expenses. While it is true that these messages also include references and links to rebate offers for more energy efficient appliances, it is clear that the primary purpose of those communications is to encourage energy efficiency and conservation and to provide information to customers about opportunities and methods to effectively reduce energy and gas consumption. Similarly, other messages like Figure 4—which informs customers about backup generators and safe use of gas appliances in emergency situations—are primarily focused on encouraging efficient and safe use of utility gas services during power outages and natural disasters and informing customers about potential resiliency opportunities.

Q. The Coalition argues that including these gas appliance messages with references and links to rebates and incentives in the Company's Category A customer communications expense is contrary to NW Natural's assertion that the Company is not seeking cost recovery in this rate case for expenses related to rebates or incentives for gas appliances.[35] Is the Coalition correct?

A. No. Communicating with customers about ways for customers to increase the efficiency of their gas appliances through upgrades to high-efficiency appliances is clearly the primary intent of the messages showing rebates and incentives for high-efficiency appliances. The actual rebates themselves are not funded by customers, and the inclusion of the rebates is a secondary purpose of the messages.

Q. Please comment on whether any of the messages referenced by the Coalition have been wholly or partially attributed to Category C.

A. The cost strategy the Company took with regard to the printed "Comfort Zone" newsletters was to charge about 25 percent of the printing costs to Category C to cover any messages that could be interpreted as promotional in nature. After further consideration, the Company should have adopted the same approach for the electronic newsletter. NW Natural has made a note of this and will reduce the revenue requirement for Category A by $8,000 or about 25 percent of the cost for distributing the electronic "Comfort Zone" newsletters.

[35] Coalition/200, Apter-Connolly/49.

Q. Does the Coalition make any other claims regarding the gas appliance customer communications?

A. Yes. The Coalition further asserts that the Company's gas appliance messages include misinformation about the health impacts of gas stoves because the communications state that customers should turn on their fan hoods regardless of stove type, apparently "implying that emissions from gas stoves and electric stoves have the same health impacts."[36] A copy of the message referenced by the Coalition is provided in Figure 9 below.

Figure 9. e-Newsletter Smart Cooking Communication

As an initial matter, the primary purpose of the communication in Figure 9 above is to educate customers regarding the use of proper ventilation when cooking, which is necessary when cooking on any appliance—whether gas or electric. This advertising is appropriately considered Category A because it addresses a

[36] Coalition/200, Apter-Connolly/48; Coalition/217, Apter-Connolly/31.

contemporary item of customer interest—cooking and proper appliance use. Moreover, contrary to the Coalition's baseless assertions, nothing in Figure 9 implies greater, equal, or less health impacts with respect to emissions from gas versus electric cooktops. It is factually accurate that good ventilation in the kitchen during high temperature cooking, regardless of whether you are using a natural gas or electric cooktop, is a best safety practice. Proper ventilation not only addresses fumes and gases from cooking (which occur whether using gas or electric cooktops), but also reduces airborne grease, prevents the build-up of grease, and decreases the temperature around the stove area. In short, regardless of the type of cooktop used, proper ventilation reduces indoor pollutants and prevents kitchen incidents such as grease burns, smoke and overheating, and fires.

3. Smart Energy Program

Q. Please describe the Coalition's arguments regarding NW's Natural's customer communications regarding the Smart Energy Program.

A. The Coalition argues that, regardless of whether the purpose of the customer communications is to encourage customers to join the Smart Energy Program to lower GHG emissions by contributing to a mix of carbon offsets and renewable natural gas projects, the fact that the program is offered by a utility that offers gas services means that such messages are *per se* promotional/institutional Category C advertising expenses.[37] In essence, the Coalition argues that

[37] Coalition/200, Apter-Connolly/51-52.

customer communications that contain anything less than statements encouraging customers to explicitly disconnect or reduce gas service are promotional.[38]

Q. How do you respond?

A. As an initial matter, the primary purpose of the Smart Energy Program customer communications is clearly to address customer environmental considerations and other items of customer interest (such as climate change and ways to mitigate emissions from natural gas use), which are included under utility information advertising expenses, Category A. If the Coalition's arguments were taken to their ultimate conclusion, all customer communications by any energy utility service offering opportunities for customers to invest in carbon offsets and renewable energy projects would be considered promotional unless there were zero emissions associated with that utility service and its programs, which is not the case in reality.

4. Climate Change Communications

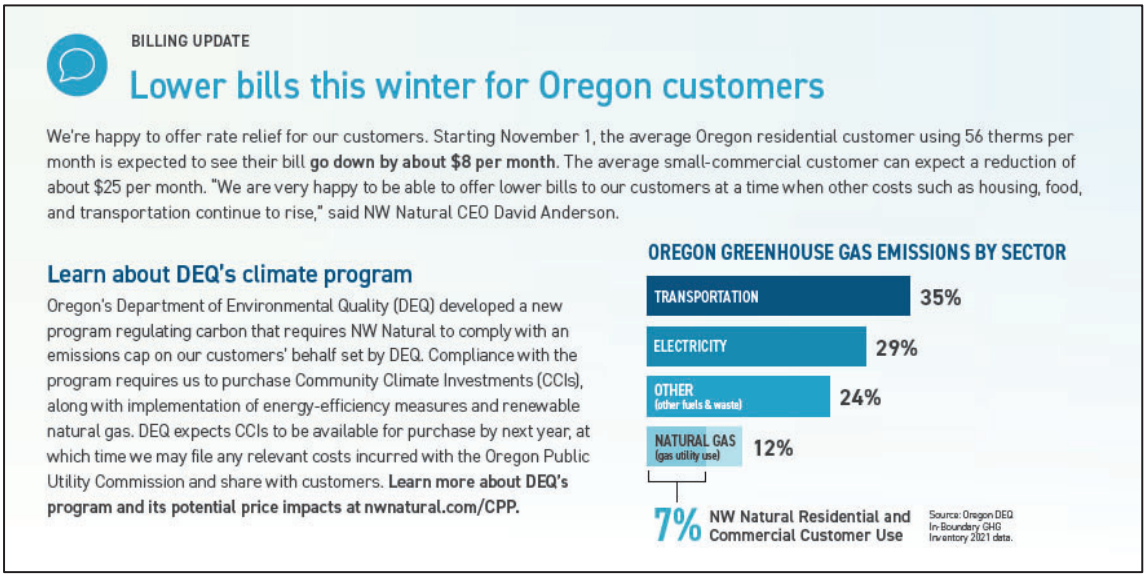
Q. Please describe the Coalition's arguments concerning NW Natural's customer communications regarding climate change, and Oregon's invalidated and future greenhouse gas regulations.

A. The Coalition argues that NW Natural's customer communications regarding climate change-related conservation efforts, GHG emissions data, electrification, and the status of Oregon's invalidated and future greenhouse gas regulations and

[38] Coalition/200, Apter-Connolly/52 ("By participating in this program, customers may conclude they can responsibly maintain their gas service or level of gas consumption instead of disconnecting service or at least reducing gas usage out of concern for climate impacts.").

resulting impacts of that decision on rates are political Category D advertising and are therefore not recoverable.[39] In particular, the Coalition points to the "Comfort Zone" newsletter where the Company informed its customers about the invalidated greenhouse gas regulations and directed its customers to a webpage that discussed the status of the invalidated greenhouse gas regulations and its impacts on customer rates.[40]

Figure 10. "Comfort Zone" Invalidated CPP Customer Communication



The Coalition claims that these messages do not "provide information" about the invalidated CPP; rather, the purpose of these customer communications are to "influence public opinion against the CPP."[41]

[39] Coalition/200, Apter-Connolly/49-50.

[40] Coalition/200, Apter-Connolly/49-50; Coalition/216, Apter-Connolly/15.

[41] Coalition/200, Apter-Connolly/49-50.

Q. How do you respond?

A. The Coalition mischaracterizes the customer communications regarding the invalidated CPP; the messages were not intended to influence public opinion against the invalidated CPP, but rather to inform the Company's customers of the invalidated CPP, provide the current status of the invalidated rules, and notify customers that the anticipated rate increase attributed to compliance with the invalidated CPP would not occur at the time. These messages clearly fall under utility information advertising (Category A), which includes communications regarding environmental considerations and rate increases. Moreover, NW Natural truthfully and transparently informed customers on its position on the invalidated CPP, why the court invalidated the CPP, and the Company's commitment to working with the Oregon Department of Environmental Quality ("DEQ"), customers, and the community on the potential successor CPP rules so that the rules are lawfully promulgated, "focused on emission reductions, have clear accountability for effectiveness, and retain energy affordability and security."[42] To simply "provide information" on the invalidated CPP, as the Coalition suggests, without informing customers on the current status of those rules, resulting impacts on rates, and the Company's position would be incomplete and a disservice to the Company's customers.[43]

[42] *New DEQ Climate Regulation in Oregon*, NW Natural, https://www.nwnatural.com/about-us/rates-and-regulations/cpp (last visited May 28, 2024).

[43] Coalition/200, Apter-Connolly/49.

Q. The Coalition also takes issue with the Company including a link in the September 2023 "Comfort Zone" newsletter that directs the reader to the webpage nwnatural.com/cpp,[44] and argues that it should not be recoverable from customers. How do you respond?

A. The webpage in question is simply an extension of all invalidated CPP communications and provides timely status updates for the program development, as costs associated with the invalidated CPP may impact customer rates.

Q. The Coalition also claims that NW Natural's customer communications regarding GHG emissions data and electrification are misleading and should be characterized as political Category D advertising because they minimize the role of NW Natural's contribution to climate change and mislead customers about the role of electrification in mitigating GHG emissions.[45] Is the Coalition correct?

A. No. As an initial matter, the customer communications referenced by the Coalition, which include GHG data from the DEQ and other third-party sources, such as the City of Portland Bureau of Planning and Sustainability, clearly fall under utility information advertising (Category A), which includes advertising regarding environmental considerations. While the Coalition claims without basis that the

[44] The particular statement that the Coalition excerpts to is "With the prior CPP rules invalidated, the costs we had anticipated our customers would begin seeing this year to comply with the program are no longer required. We are pleased with the Court's decision because the program was designed in a way that would have been costly to customers and without accountability for quantifiable emission reduction benefits." Coalition/200, Apter-Connolly/49-50.

[45] Coalition/200, Apter-Connolly/50; Coalition/217, Apter-Connolly/24.

information presented by NW Natural is misleading, it does not point to any data, data sources, or information provided by NW Natural that is factually incorrect.

5. Rate Impact Information

Q. The Coalition also argues that NW Natural's webpage "Rate changes for 2023-2024" is political Category D advertising because it refers to compliance costs for the invalidated CPP and is therefore misleading.[46] How do you respond?

A. In this example, the Coalition is leaving out an essential detail. The communication at issue provides an update regarding the rate change resulting from the Company's 2023 purchased gas cost (PGA) filing, which included costs associated with the invalidated CPP. The communication is not misleading, as it directs customers to updated information on the invalidated CPP, which informs customers that invalidated CPP compliance costs will not be included in rates as had been previously anticipated prior to invalidation of the CPP.

6. Calculation of the Coalition's Proposed Adjustment

Q. Is it clear how the Coalition arrived at its proposed Category A adjustment?

A. No, it is not clear how the Coalition arrived at its proposed $310,641 adjustment. NW Natural provided a data request to the Coalition to gain clarification. The Coalition's response did not directly address the question, and instead stated: "The Coalition does not have any work papers calculating this deduction. Please see the testimony in Coalition/200, Apter-Connolly/53, Lines 2-7, for an

[46] Coalition/200, Apter-Connolly/50-51; Coalition/213, Apter-Connolly.

explanation of this disallowance recommendation."[47] In turn, the testimony at Coalition/200, Apter-Connolly/53, Lines 2-7 recommends the removal of the Category A Test Year costs for bill inserts, electronic newsletter and website content. Proposed Test Year budgets were provided in response to UG 490 OPUC DR 337 (NW Natural/3202, Beck) and are shown below in Table 2.

TABLE 2

TOTAL CATEGORY A

Category A Channels		Total Budget		OR Test Year Budget		Total
Salaries/Overhead	$	650,000	$	573,625		
Bill inserts	$	252,000	$	222,390	$	222,390
Brochures/ Customer support Items	$	65,000	$	57,363		
eNewsletter	$	35,000	$	30,888	$	30,888
Professional Services - Design & Writing	$	150,000	$	132,375		
Website support/development	$	35,000	$	30,888	$	30,888
Postage	$	85,000	$	75,013		
Media - Production	$	50,000	$	44,125		
Media - IVR	$	10,000	$	8,825		
Media - Telephone directory	$	30,000	$	26,475		
Media - TV/Digital/Streaming	$	200,000	$	176,500		
Category A Totals	**$**	**1,562,000**	**$**	**1,378,465**	$	284,166

The total Oregon Test Year budget proposed for Bill inserts, Electronic Newsletter and Website total $284,166, not $310,641.

Q. In the event that the Commission agrees with the Coalition, should the Coalition's recommended Category A adjustment be modified?

A. Yes. As a starting point, the Coalition's deduction should be lowered to $284,166. The remainder of the recommended deductions should also be removed as explained further my Reply Testimony.

[47] NW Natural/3201, Beck (Coalition's response to UG 490 NWN to Coalition DR 20).

IV. CATEGORY B CUSTOMER COMMUNICATIONS EXPENSE

A. Staff's Recommendations

Q. What were the results of Staff's review of NW Natural's proposed Category B customer communication expense?

A. Staff confirmed that the customer communications identified by NW Natural under the Category B expense were related to safety-related communications.[48]

Q. What is Staff's recommendation regarding Category B customer communications expense?

A. Staff found that while the Company's proposed Category B expense is presumed reasonable, that presumption is overcome due to the increase proposed by NW Natural. Staff recommends determining the Test Year expense for Category B advertising by averaging in the expense for the years before and after the Base Year to smooth out the increase in the Test Year.[49] This modification results in a Test Year expense of $836,078, an adjustment of $139,085 to NW Natural's proposed Test Year Category B advertising expense of $975,163.[50]

Q. What is NW Natural's response to Staff's recommendation for the Category B customer communications expense?

A. NW Natural disagrees with Staff's proposed adjustment. The incremental Category B cost is associated with the Company's multi-language safety-related content, and will allow the Company to expand the reach of its safety messaging

[48] Staff/1700, Rossow/9.

[49] Staff/1700, Rossow/9-10.

[50] Staff/1700, Rossow/10.

beyond English and Spanish-speaking households to also reach customers that speak Chinese and Russian. If Staff's adjustment were to be adopted by the Commission, the multi-language advertising campaign would need to be significantly reduced or not developed at all. As I mentioned in Direct Testimony and further below, Spanish, Russian and Chinese speaking residents make up more than 36 percent of adults in some Portland Zip Codes (our largest service area). These non-native English-speaking residents could struggle to understand the many nuances of natural gas safety. Native language advertising performs better because it is created with the specific target audience in mind, using language and distinctions the audience understands resulting in better brain processing, connection and cultural relevance. While NW Natural can appreciate Staff's position with regard to reducing the cost impact to customers overall, NW Natural disagrees with Staff's proposed adjustment.

B. Coalition's Recommendations

Q. What is the Coalition's recommendation regarding Category B customer communications expense?

A. The Coalition recommends deducting all costs for advertising unrelated to preventing leaks from gas pipelines, which the Coalition estimates as being a reduction of $80,000 from NW Natural's Category B customer communications expense.[51] In other words, the Coalition recommends deducting the entire system-wide Test Year budget for safety-related (Category B) bill inserts and brochures for

[51] Coalition/200, Apter-Connolly/53-55.

customers, as NW Natural is only asking for $70,600 from Oregon customers.[52] In particular, the Coalition argues that Category B expenses for communications regarding use of ventilation fans in the kitchen, the safe operation and installation of gas appliances, operating gas appliances during a blackout, and regarding NW Natural's pipeline system should be removed from recovery.[53]

Q. Why does the Coalition claim that communications regarding the safe use of the natural gas system should not be recoverable expenses?

A. The Coalition argues that NW Natural is not legally mandated to provide these customer communications, and that these advertisements are promotional in nature.

Q. How do you respond?

A. I disagree. None of NW Natural Category B communications are promotional. At NW Natural**,** safety guides everything we do and keeping customers, employees and the communities we serve safe around natural gas – pipelines, house lines, meters and appliances -- are all considered under the intent of the law. Guidance is provided by law through Federal Regulations by the U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration and RP1162 and governed and inspected by the Commission. Although I am not a lawyer, I disagree with the Coalition's position that the law has a limited focus only with regard to pipeline safety and preventing damages to the pipeline. The intent of the law is to protect people and property. Educating the public about natural

[52] NW Natural/3202, Beck (Company's response to UG 490 OPUC DR 337).

[53] Coalition/200, Apter-Connolly/53-55.

gas safety is essential. Advertising campaigns, guidelines, and community outreach help inform individuals about safe practices, proper use of equipment, emergency and prevention procedures, the signs of a gas leak and how to safely respond. The Commission's mission "is to ensure Oregonians have access to safe, reliable and fairly priced utility services that advance state policy and promote the public interest". Further, one of the Commission's guiding principles is to "ensure the safety, reliability and quality of essential utility services."[54] NW Natural understands these principles to encompass all safety education topics in the Public Safety Awareness Plan and Standard Practices document to ensure the customers and communities we serve know how to be safe around natural gas. The Commission regularly inspects the Company's Public Safety Awareness Plan to ensure compliance. NW Natural's Public Safety Awareness Plan was last inspected on October 3, 2023, where no issues or concerns were identified by the Commission Safety Staff.

V. ENROLLMENT IN BILL DISCOUNT PROGRAM AND INVESTMENT IN MULTI-LINGUAL OUTREACH

Q. The Coalition argues that NW Natural did not invest sufficient funds to advertise the bill discount program.[55] How do you respond?

A. I disagree with the Coalition's opinion. NW Natural deployed an extensive and comprehensive targeted, and multi-channel approach to advertising the bill

[54] https://www.oregon.gov/puc/about-us/pages/default.aspx.

[55] Coalition/300, Fain-Segovia Rodriguez-Daryanani/26-27.

discount program to customers. Examples of direct engagement where materials and marketing toolkits were shared include:

- More than 250 Community Based Organizations
- More than 100 School Districts in every NW Natural County (representing 835 schools)
- Community colleges and Headstart Agencies
- Over 40 County, Federal & State Agencies
- In-person events

Publications distributed:

- 65 Neighborhood Newsletters
- More than 100 City Homepages
- 95 library homepages
- 50,000 brochures distributed and 5,000 pre-launch program postcards distributed to schools and homebound Seniors

Redoubled and Data-informed outreach:

- Low-income communities with low bill discount program enrollment rates
- Schools with the highest rates of student eligibility for free and reduced meals
- Title 1 Schools

Other advertising

- Dedicated web section
- Produced radio spots

- TV Public Service Announcements
- Digital Ads
  - Delivered more than 1.6 million impressions
- NW Natural Customer communications
  - Five email communications
  - Six bill insert articles
  - Letter sent to all customers that were automatically enrolled

In my nearly 20 years with the Company, I have not seen a more comprehensive and wide-reaching approach to advertising a Company program. The positive results point to the successful execution of the Company's communication strategy, outreach and advertising efforts.

Q. The Coalition also argues that the methods NW Natural uses to advertise the bill discount program do not match the preferred method of outreach for customers.[56] Do you agree?

A. No, I do not agree. The assumptions by the Coalition are inaccurate. The Coalition references the Low Income Needs Assessment ("LINA") study for reporting preferred methods of outreach and awareness of the program. First, this statement is not valid because at the time of the LINA, the bill discount program did not exist. Second, and with the LINA in mind, the Company's 2023 communications plan ***did*** include advertising to customers through emails, electronic newsletters and bill inserts. Additionally, there is a permanent section

[56] Coalition/300, Fain-Segovia Rodriguez-Daryanani/26-27.

on the NW Natural website (https://www.nwnatural.com/account/bill-discount-program). All of the channels mentioned above represent the top three channels identified by the LINA.

Q. The Coalition claims that NW Natural's investment in multi-lingual outreach for the bill discount program is not justified because survey data show radio and TV advertisements are not effective for increasing awareness of the program.[57] What is your response?

A. Holistically, I do not agree with the Coalition's claims regarding multi-lingual advertising. The LINA is one data source, but there are many other sources to consider when developing communication and outreach plans. Moreover, to provide effective outreach, multiple channels need to be in play to meet customers where they consume media – TV, radio, community events, social media, etc.

- First, NW Natural's annual safety survey of customers (and general public) show that TV and radio are the number two and number four most important source for news and information, respectively.
- Second, the multi-language media proposal provided with my original testimony shows 79 percent of Spanish-speaking adults watch connected TV (streaming TV) and 85 percent use streaming audio.
- Third, 10.4 percent of households in Portland are Spanish speaking, which equates to over 479,000 adults. Additionally, 97 percent of Spanish-speaking households listen to AM/FM Radio.

[57] Coalition/300, Fain-Segovia Rodriguez-Daryanani/26-27.

- Fourth, Spanish, Russian and Chinese speaking residents make up more than 36 percent of adults in some Portland Zip Codes.

This data demonstrates that it would be irresponsible to not include TV and radio into the media mix and in native language to be effective and can produce better engagement by providing cultural nuance and context, emotional connection, and reduced misunderstandings, and building trust.

Q. Does this conclude your Reply Testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibits of Corey A. Beck

CUSTOMER COMMUNICATIONS
EXHIBITS 3201 – 3202

June 4, 2024

EXHIBITS 3201-3202– CUSTOMER COMMUNICATIONS

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Exhibit 3202 – UG 490 OPUC DR 337 NWN Response 1

UG 490 OPUC DR 337 Attachment 1 (Excel)

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Corey A. Beck

CUSTOMER COMMUNICATIONS EXHIBIT 3201

June 4, 2024

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON
UG 490

Coalition's Data Request Response

Dated: May 15, 2024

Request: UG 490 NWN DR 20

Please provide a workpaper calculating the $310,641 amount that the Coalition recommends deducting from the Company's Category A budget, at Coalition/200, Apter-Connolly/37, Lines 2-3.

Response:

The Coalition does not have any work papers calculating this deduction. Please see the testimony in Coalition/200, Apter-Connolly/53, Lines 2-7, for an explanation of this disallowance recommendation.

Earthjustice
810 Third Ave. Suite 610
Seattle, WA 98104
(206) 343-7340

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Corey A. Beck

CUSTOMER COMMUNICATIONS EXHIBIT 3202

Part of this exhibit is being provided in its native, Excel format.

June 4, 2024

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 337

As a follow-up to SDR 104, please provide a breakdown of the smaller categories that comprise Category A, and B. For example, for Category B, show what the breakdown/percentages (and totals) are for products and services, versus public safety or corporate communications.

Response:

Please see the UG 490 OPUC DR 337 Attachment 1 for detail regarding Category A and B. Tab 1 is for Category A, and Tab 2 is for Category B.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Reply Testimony of Kathryn M. Williams

POLITICAL ACTIVITIES EXHIBIT 3300

REDACTED

June 4, 2024

EXHIBIT 3300- REPLY TESTIMONY – POLITICAL ACTIVITIES

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I. INTRODUCTION AND SUMMARY

Q. Are you the same Kathryn M. Williams who presented Direct Testimony in this proceeding on behalf of Northwest Natural Gas Company dba NW Natural ("NW Natural" or the "Company")?

A. Yes, I presented NW Natural/1200, Williams.

Q. What is the purpose of your Reply Testimony in this proceeding?

A. The purpose of my Reply Testimony is to respond to the Opening Testimony of Paul Rossow on behalf of Staff for the Public Utility Commission of Oregon ("Commission"), as well as the Opening Testimony of Nora Apter of the Oregon Environmental Council ("OEC") and Meredith Connolly of Climate Solutions on behalf of the Coalition,[1] concerning NW Natural's political activity/lobbying expenses for the Test Year (November 2024 through October 2025).

Q. Please summarize your Reply Testimony.

A. In my testimony, I:

- Provide relevant background regarding political activity or lobbying expenses and direction from Commission Order No. 22-388 in the Company's most recent general rate case, docket UG 435, as it applies to this general rate case;
- Respond to Staff's recommendation regarding political activity/lobbying expenses; and

[1] The Coalition includes the Coalition of Communities of Color, Climate Solutions, Verde, Columbia Riverkeeper, Oregon Environmental Council, Community Energy Project, and Sierra Club.

- Respond to the Coalition's recommended adjustments for political activity/lobbying expenses;

Q. Do you include any exhibits with your testimony?

A. Yes, I am presenting the following exhibits:

- NW Natural/3301, Williams (Company's textual response to UG 490 Coalition DR 145).
- Confidential NW Natural/3302, Williams (Company's Confidential UG 490 Coalition DR 145 Attachment 1).
- Confidential NW Natural/3303, Williams (Company's job description of a certain employee of the Government Affairs team, provided as Confidential UG 490 Coalition DR 290 Attachment 4).
- Confidential NW Natural/3304, Williams (Company's job descriptions of the other employees of the Government Affairs team, provided as Confidential Amended Response to UG 490 Coalition DR 290, Confidential UG 490 Coalition DR 277 Attachment 2, Confidential UG 490 Coalition DR 277 Attachment 4, and Confidential UG 490 Coalition DR 290 Attachments 1-3 and 5-6).
- Confidential NW Natural/3305, Williams (Company's Confidential response to UG 490 Coalition DR 291).

II. BACKGROUND REGARDING POLITICAL ACTIVITY EXPENSES AND ORDER NO. 22-388

Q. Please summarize the Commission's direction regarding Government Affairs expense, and specifically regarding political activities in Order No. 22-388.

A. With respect to recording expense information related to political activities or lobbying, the Commission stated that, "[g]oing forward, we expect NW Natural to provide detailed expense information that clearly categorizes its [political] activity."[2] The Commission specifically noted that:

> NW Natural should be clear whether it is engaging, for example, primarily in an informational capacity in response to local government requests for assistance in developing and meeting climate policies, versus engaging with local governments with an intention to advocate against particular policies and develop support for others.[3]

Q. How has the Commission defined political activity or lobbying?

A. While I am not a lawyer, from the Company's review of available precedent, it appears that the Commission has not previously defined political activity or lobbying. However, the Commission cited the Federal Energy Regulatory Commission's ("FERC") 18 Code of Federal Regulations ("CFR") Section 367.4264 in Order No. 22-388 when it stated that the Commission's precedent that "utilities are not permitted to recover expenses associated with political lobbying"

[2] *In re Northwest Natural Gas Co., dba NW Natural, Request for a General Rate Revision,* Docket No. UG 435, Order No. 22-388 at 23 (Oct. 24, 2022).

[3] *Id.*

is "similar to FERC's regulations prohibiting political activities and lobbying."[4] Accordingly, as discussed in more detail below, the Company's accountants have informed me that NW Natural has used 18 CFR Section 367.4264 as guidance in determining political activities and lobbying.

Q. What is the FERC definition of lobbying?

A. The FERC guidance in 18 CFR Section 367.4264 describes the below-the-line (i.e., non-recoverable) FERC account 426.4, as follows:

> 426.4 Expenditures for certain civic, political and related activities. This account shall include expenditures for the purpose of influencing public opinion with respect to the election or appointment of public officials, referenda, legislation, or ordinances (either with respect to the possible adoption of new referenda, legislation or ordinances or repeal or modification of existing referenda, legislation or ordinances) or approval, modification, or revocation of franchises; or for the purpose of influencing the decisions of public officials, but shall not include such expenditures which are directly related to appearances before regulatory or other governmental bodies in connection with the reporting utility's existing or proposed operations.

Q. After the Commission issued its Order No. 22-388 in docket UG 435, what actions did the Company take to meet the Commission's going-forward expectation that NW Natural provide detailed expense information that clearly categorizes its political activities?

A. As discussed in my Direct Testimony,[5] the Company updated its time-tracking policy for political activities, or activities intended to influence a legislative body,

[4] *In re Northwest Natural Gas Co., dba NW Natural, Request for a General Rate Revision,* Docket No. UG 435, Order No. 22-388 at 22, n.70 (Oct. 24, 2022).

[5] NW Natural/1200, Williams/3-4.

through exception time reporting. Effective January 1, 2023, employees have been entering exception time into the Company's time tracking system, called "WorkForce," for time spent each working day on such activities. The Company created a "Time Charging Procedures – Political Activities" ("General Procedure") to help its employees with the exception time reporting function. A copy of the General Procedure is attached to my Direct Testimony as Confidential NW Natural/1201, Williams. The Company's employees have been trained on use of the General Procedure, which, as discussed in my Direct Testimony, provides detailed instructions for exception time reporting of political activities. Exception time is to be reported in half-hour increments daily, in the cost center identified in the General Procedure (Confidential NW Natural/1201, Williams). The General Procedure provides illustrative examples for use in exception time reporting and step-by-step screen shots of the "WorkForce" time entry system.

Q. Does NW Natural seek recovery of expense for political activities or lobbying in this rate case?

A. No. As I discussed in my Direct Testimony, the Company is not seeking recovery for these types of expenses, including incidental expenses like mileage related to meetings involving political activities, in the Test Year.[6]

[6] NW Natural/1200, Williams/2-7.

Q. What types of political activity/lobbying expenses did the Company exclude from its request for cost recovery?

A. Through discovery, the Company demonstrated that it time-tracks and directly allocates the costs incurred for political activities/lobbying to non-recoverable accounts. The Company's time tracking is provided in NW Natural/3301, Williams, which is a copy of the Company's narrative response to UG 490 Coalition DR 145, and Confidential NW Natural/3302, Williams, which is a copy of the Company's Confidential UG 490 Coalition DR 145 Attachment 1.

Q. The total Government Affairs Test Year expense is $1,725,922.[7] Does this include exception time?

A. No, the Company removed all exception time and related costs from this amount. As noted later in my Reply Testimony, the Company does not oppose Staff's recommended Oregon-allocated adjustment of $11,047 regarding an identified "104 lobbying transactions" recorded to cost elements titled "Meals and Entertainment" and "Business Travel."[8]

Q. How much did NW Natural remove from its request for cost recovery through exception time reporting

A. Confidential NW Natural/3302, Williams, shows, by summing the dollar amounts in Column (C) ("Val.in rep.cur."), that the Company removed $625,160 of Base

[7] Coalition/241-242, Apter-Connolly (the Company's response to UG 490 OPUC DR 343, including its Attachment 1).

[8] Staff/1700, Rossow/4.

Year expense from its request for cost recovery through exception time reporting in FERC Account 426.4.

Q. How would you describe the amount of Base Year expense removed from the Company's request for cost recovery through exception time reporting in FERC Account 426.4, compared with the historical allocation method used before 2023?

A. Noting that exception time reported $625,160 in the Base Year (2023), compared with $506,223 in 2021 and $592,226 (in 2022) using the previous historical allocation method ,[9] the exception time reporting under the General Procedure has provided us a higher level of confidence that we are and have been accurately reporting our lobbying and political activities to non-recoverable accounts. Of course, these dollar amounts provide snapshots of our lobbying and political activities that may vary from year to year. With that said, based on the exception time that we reported under the General Procedure in the Base Year, the Company is appropriately categorizing its lobbying and political activities to cost accounts that are not recovered from our customers.

[9] The Coalition's testifies that the Company "reports that for 2023, $775,673 was charged to FERC 426.4 (up from $506,223 in 2022)…." Coalition/200, Apter-Connolly/56. Actually, as shown in cited Exhibit Coalition/242, Apter-Connolly, $506,223 was charged-out in 2021 (not 2022) and $592,226 was charged-out in 2022.

III. STAFF'S RECOMMENDATIONS

Q. Did Staff analyze the Company's Government Affairs expense?

A. Yes. Staff reviewed the Company's Direct Testimony and issued 11 data requests, and also analyzed the Company's response to Standard Data Request No. 57.[10]

Q. Does Staff provide any guidance on which types of activity can fall under the political activity/lobbying category?

A. Staff states that political activities and lobbying can, but do not necessarily, include the following:

- Directly communicating with officials;
- Providing transportation for elected officials;
- Attending government conferences and expressing special interest views;
- Drafting special interest legislation and presenting it to a legislator for consideration;
- Providing support for elected officials on trade missions, by providing in kind services to special interest groups;
- Hosting receptions for congressional delegations; and
- Attempting to influence legislators and other public officials to introduce or support measures that favor some special interest.[11]

[10] Staff/1700, Rossow/4.

[11] Staff/1700, Rossow/3.

Q. How does the Company respond to Staff's list of activities that can fall under the political activity/lobbying category?

A. The Company views Staff's list of activities that can fall under the political activity/lobbying category as reasonable, and appreciates Staff's effort to provide greater specificity to stakeholders.

Q. Has the Company tracked as exception time the activities listed by Staff?

A. Yes. The Company tracks the activities listed by Staff as exception time through the General Procedure. Out of an abundance of caution, our exception time reporting likely has captured more than the items on this list. That time is recorded in a non-utility account, and the wages, compensation, and benefits/overheads sought for recovery in this rate case do not include the dollars associated with that tracked time.

Q. What does Staff recommend regarding adjustments for political activity/lobbying expenses?

A. Staff identified "104 lobbying transactions" recorded to cost elements titled "Meals and Entertainment" and "Business Travel," and recommends excluding 100 percent of those expenses, which in total equates to an Oregon Base Year allocated amount of $11,047.[12] Staff applied All-Urban Consumer Price Index (CPI) inflation factors of 2.7 percent and 2.0 percent in 2024 and 2025, respectively, resulting in an Oregon escalated Test Year adjustment to lobbying

[12] Staff/1700, Rossow/4.

expenses of $11,572.[13] Staff therefore recommends an adjustment of $11,572 for the Test Year.

Q. How does the Company respond to Staff's recommendation?

A. The Company does not oppose Staff's recommended adjustment.

IV. THE COALITION'S RECOMMENDATIONS

Q. What does the Coalition recommend regarding adjustments for political activity/lobbying expenses?

A. The Coalition recommends that the Commission "hold the Company responsible for failing to address the concerns raised by the Commission in Order No. 22-388 and previous Commission precedent"[14] by completely eliminating the Company's Test Year expense for employee salaries and office supplies and expense for the Government Affairs team, which is $1,725,922.[15]

Q. What is the rationale underlying the Coalition's recommendation?

A. The Coalition argues that: (1) NW Natural's policy for distinguishing exception time in the General Procedure is too narrow and does not include all political activities as defined in the FERC definition, 18 CFR § 367.4264; and (2) the Company's tracking mechanism fails to provide the detailed reporting of political activities as directed by the Commission in Order No. 22-388.[16] According to the Coalition, without *positive* reporting for time spent on utility activities, "stakeholders have no

[13] Staff/1700, Rossow/4.

[14] Coalition/200, Apter-Connolly/58.

[15] Coalition/200, Apter-Connolly/68-69.

[16] Coalition/200, Apter-Connolly/62, 68-69.

means by which to confirm employees are appropriately categorizing their time."[17] Without such "actual evidence" that the Company's employees are engaged in "properly recoverable activities," the Coalition argues that "the assumption should be that they are not."[18] For these reasons, the Coalition argues that NW Natural employees have undercounted the total hours that should have been billed below the line as political activity/lobbying costs.[19]

Q. With respect to the first point, the Coalition argues that NW Natural's policy is inconsistent with the Commission's direction in UG 435 and inconsistent with 18 CFR Section 367.4264 because the Company's policy does not specifically address lobbying for the purpose of influencing the decisions of public officials, and instead only applies to legislative activities. Is this true?

A. No. As illustrated in the General Procedure, one specific example of exception time tracking is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**[20] This example is illustrative only, but clearly demonstrates that the Company is also tracking efforts beyond the legislative context through exception time.

[17] Coalition/200, Apter-Connolly/58.

[18] Coalition/200, Apter-Connolly/58.

[19] Coalition/200, Apter-Connolly/68-69.

[20] Confidential NW Natural/1201, Williams/3.

Q. The Coalition also argues that the Company has undercounted the number of hours (and the costs) of its employees engaging in political activities because it did not include hours and costs related to attempting to influence non-legislative public officials.[21] How do you respond?

A. The Company developed, implemented and is managing its General Procedure consistent with the Commission's holding reiterated in Order No. 22-388 that, "[u]nder this Commission's precedent, utilities are not permitted to recover expenses associated with political lobbying."[22] The Company reasonably describes "political lobbying" as time spent working on "political activities, or activities intended to influence a legislative body."[23] The actual definition of lobbying can differ across jurisdictions and we comply with each jurisdiction's requirements. Simply for reference, Webster's dictionary defines "lobbying" as "conduct[ing] activities aimed at influencing public officials and especially members of a legislative body or legislation."[24] The Company drafted and interprets the General Procedure to appropriately cover communications intended to influence "any member or employee of a legislative body, *or with any governmental official or employee who may participate in the formulation of legislation*."[25] As such, the General Procedure governs activities highlighted by the Commission, including

[21] Coalition/200, Apter-Connolly/67.

[22] *In re Northwest Natural Gas Co., dba NW Natural, Request for a General Rate Revision,* Docket No. UG 435, Order No. 22-388 at 22 (Oct. 24, 2022).

[23] NW Natural/1200, Williams/3.

[24] https://www.merriam-webster.com/dictionary/lobbying.

[25] NW Natural/1200, Williams/4 (emphasis added).

"efforts to influence city or county officials, such as the communications with Multnomah County officials and the communications with Milwaukie city councilors"[26] and "engaging with municipalities or other jurisdictions regarding topics such as local climate change initiatives."[27] Importantly, the General Procedure governs all sides of political activity and lobbying, such as when the Company submits support of the Commission's budget to legislators.

Under the General Procedure, political lobbying does not include communications with "judicial, executive or administrative body (e.g., Department of Environmental Quality, Department of Energy, Treasury, school boards, housing authorities, sewer and water districts, zoning boards), whether elected or appointed." The Company followed the language in FERC Account 426.4 that political lobbying activities "shall not include such expenditures which are directly related to appearances before regulatory or other governmental bodies in connection with the reporting utility's existing or proposed operations."[28] The Company also used as guidance the Commission's Order No. 22-388, which did not hold that communications "with judicial, executive or administrative body …, whether elected or appointed" are political lobbying activities that the Company should exception time report. Just because the Company holds communications with "judicial, executive or administrative body (e.g., Department of Environmental

[26] *In re Northwest Natural Gas Co., dba NW Natural, Request for a General Rate Revision,* Docket No. UG 435, Order No. 22-388 at 22 (Oct. 24, 2022).

[27] *In re Northwest Natural Gas Co., dba NW Natural, Request for a General Rate Revision,* Docket No. UG 435, Order No. 22-388 at 23 (Oct. 24, 2022).

[28] 18 CFR § 367.4264.

Quality, Department of Energy, Treasury, school boards, housing authorities, sewer and water districts, zoning boards), whether elected or appointed" as something other than political activities/lobbying, does not necessarily mean that the Company always treats such communications as recoverable. As noted later in my Reply Testimony, the Company does use other below-the-line cost centers to track time and activities for which it does not seek cost recovery.

Q. How do you respond to the Coalition's testimony about the April 16, 2024, public hearing on NW Natural's rate increase?

A. The Coalition suggests that the Company "choreographed" testimony provided by "numerous organizations, including homeowners and representatives of chambers of commerce … in favor of NW Natural's proposed LEA [line extension allowance]," and that any such activities constitute political lobbying that should not be paid by ratepayers.[29]

For the record, NW Natural did correspond with organizations regarding participation in the public hearing on April 16, 2024, and/or submitting public comments for this rate case, UG 490. It is important that these stakeholders are aware of the regulatory process available to them in this rate case and the positions being taken by parties that may affect them, their businesses and their constituents. It is with these ideals in mind that NW Natural proactively undertakes informational engagement and education with organizations such as those identified by the Coalition.

[29] Coalition/200, Apter-Connolly/62-63.

Although NW Natural believes that such correspondence is part of its core utility functions for which ratepayer support would be appropriate, the Company is not seeking cost recovery in this rate case for any of its time or activities related to corresponding with any of those organizations regarding participation in the public hearing on April 16, 2024, and/or submitting public comments for this rate case, UG 490. The Company has booked such time and activities to a non-utility (i.e., below-the-line) Civic cost center (FERC account) for which it does not seek cost recovery. The Company does not agree with the Coalition that such communications are political lobbying, and, out of an abundance of caution, has decided to book its time associated with such activities to a non-recoverable account.

Q. The Coalition also argues that NW Natural undercounted the number of hours (and the costs) of its employees engaging in political activities because "it must have included time beyond *responding* to public official inquiries."[30] How do you respond?

A. As stated in my Direct Testimony, the Company views responding to informational requests from public officials to be a core utility function that is appropriate for recovery.[31] The Commission made clear in Order No. 22-388 that engaging "*primarily* in an informational capacity in response to local government requests for assistance in developing and meeting climate policies" was distinct core utility

[30] Coalition/200, Apter-Connolly/67 (emphasis added).

[31] NW Natural/1200, Williams/5.

work separate and distinct from political activity/lobbying.[32] The Commission also did not find that anything other than "responding" to public officials was lobbying. Indeed, the Commission agreed with NW Natural that "communications intended purely to ensure that public officials are receiving routine information about the company and the gas system do not qualify as lobbying expenses."[33] In certain cases, routine provision of information about the Company and the gas system may be initiated by the Company, while in others, it may be initiated by the local government officials.

The critical factor is the employee's ***intent***. If the employee's *intent* is to influence any member or employee of a legislative body, or with any governmental official or employee who may participate in the formulation of legislation, the employee tracks and charges out of the utility the time associated with those intended efforts. If the employee's *intent* is not to influence, but rather provide information to elected officials or their staff or the general public regarding NW Natural as a utility, then the employee treats the time associated with engagement as a core utility function that is not exception time reported.

And, importantly, an employee does not determine his or her intent in isolation of other employees. Employees are trained on the General Procedure, have been reviewing their exception time together, and discuss hypothetical and actual scenarios, and whether and how they should be exception time reporting

[32] *In re Northwest Natural Gas Co., dba NW Natural, Request for a General Rate Revision,* Docket No. UG 435, Order No. 22-388 at 23 (Oct. 24, 2022) (emphasis added).

[33] *Id.*

under the General Procedure in those instances. This helps those employees calibrate their exception time tracking work with each other and promotes consistency across the employees. In addition, the Accounting department has reviewed exception time reporting several times in 2023, and we have made adjustments as appropriate. And, when a situation arises that arguably may or may not be time spent on political activity/lobbying, we err on the side of caution and exception time report it so customers do not pay for that time.

Q. With respect to the second point, the Coalition argues that the Company's current tracking mechanism "reveals only what the *company* believes is lobbying, leaving no means by which the Commission or stakeholders can confirm whether NW Natural's employees have properly characterized their time."[34] Is the Coalition correct?

A. No. The Company provided an explanation as to why many of its Government Affairs activities are core utility activities and not political activities or lobbying, and also demonstrated that it allocates costs for political activities and lobbying outside the utility.

To the extent that the Coalition is suggesting that NW Natural needs to provide detailed time tracking for all of its core utility functions as well, the Company opposes such a proposal. To NW Natural's knowledge, no utility tracks time for its core utility activities, and to do so discriminately here would be a sharp

[34] Coalition/200, Apter-Connolly/67.

departure from prior Commission practice, a major burden on the Company's employees and would increase costs to customers.

Q. The Coalition further argues that NW Natural's exception time tracking mechanism does not contain enough information to clarify the nature of communications between NW Natural employees and government officials.[35] Did the Company provide a detailed breakdown of the lobbying expenses in FERC Account 426.4 that it claims were excluded from this case?

A. Yes. As shown in Confidential NW Natural/3302, Williams, the Company has provided 2,263 entries of exception time reporting to FERC Account 426.4, with each entry identifying the number of hours exception time reported, the dollar value of that exception time, the cost center and FERC indicator, notes and the personnel number. The Company has provided clarity about the identity of the entity to which it is lobbying, using the naming convention provided in the General Procedure for transparency, consistency and simplicity/efficiency. In some cases, that means identifying whether the legislative body being lobbied is federal, state or local. In other instances, the time is "general" lobbying of something other than a particular jurisdiction. Later in my Reply Testimony, I will address instances in which the exception time reporting is blank in the notation field.

[35] Coalition/200, Apter-Connolly/67.

Q. As an example of alleged overcounting, the Coalition points to the time split of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL].[36] Is it unusual for members of the Government Affairs team to not perform lobbying activities 100 percent of the time?

A. No. In fact, no member of the Government Affairs team performs lobbying activities 100 percent of the time, and excepted "outside" time does vary from employee to employee. That is because each member of the Government Affairs team has two roles in their engagement with jurisdictions and performs his or her duties uniquely from other members of the Government Affairs team. In many cases, their primary role is as a subject matter expert for the utility, where they provide information to the local jurisdictions regarding NW Natural as a utility and any utility-related data they may need. For example, if a jurisdiction is working on a climate action plan, they might ask the Company for its emissions data to help inform the development of their plan. Similarly, a municipality could be considering budget issues and raising funds unrelated to climate issues. Core utility engagement includes responding to information requests from the local jurisdictions to provide input to inform the development of climate plans, sharing the Company's data, and helping local jurisdictions to better understand the context for their local climate planning initiatives. When local jurisdictions come to NW Natural with questions about the State of Oregon's climate goals, and the potential implications of natural gas bans,

[36] Coalition/200, Apter-Connolly/67-68.

it is incumbent on NW Natural to respond. Members of the Government Affairs team are responsible for providing any data requested, including the costs to customers. NW Natural considers activities in this role as a subject matter expert to be a core utility service and appropriate for cost recovery. No exception time reporting is required in these circumstances. Confidential NW Natural/1201, Williams, provides examples of core utility functions.

As part of their role, members of the Government Affairs team also act as advocates for the Company. In the advocate role of intending to influence a legislative body, the Company allocates that time to non-recoverable cost centers. Exception time reporting is required in these circumstances. Confidential NW Natural/1201, Williams, provides examples of activities intended to influence a legislative body.

It Is important to remember that only a portion of these employees' time is spent working with local and state jurisdictions. Much of their work is also focused on the utility, by helping to shape utility policies, practices and programs based on their knowledge of local and state issues, completely unrelated to lobbying or contact with public officials. For example, members of the Government Affairs team regularly spend time tracking ordinances and legislation around the State and the country (e.g., easement matters, privacy laws) in order to understand the potential impact on the Company if such ordinances and legislation were to apply to the Company. That time spent monitoring local, regional, state and federal developments does not equate to taking a position and does not constitute political activities/lobbying.

Q. The Coalition provided an exhibit containing the LinkedIn page for [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]. How do you respond?

A. As an initial matter, I would note that a LinkedIn page is not necessarily indicative of all of the job functions an individual may perform. A LinkedIn page is not an official Company job description of the position, but rather a business and employment-focused social media platform for members to network with other professionals. However, even considering the information on that page, the description of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[37] These responsibilities are core utility functions appropriate for rate recovery.

Q. Can you elaborate further on the core utility functions that are included in [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] role?

A. Yes. Confidential NW Natural/3303, Williams, is a copy of the employee's job description (provided as Confidential UG 490 Coalition DR 290 Attachment 4). In 2023, NW Natural charged 48.9 percent of the employee's salary above the line, to be recovered from customers.[38] The employee develops policy guidance for the Company on specific and complex strategic business and environmental

[37] Confidential Coalition/243, Apter-Connolly.

[38] NW Natural/3305, Williams (Company response to UG 490 Coalition DR 291).

issues. In addition, the employee monitors activity and prepares reviews for Company subject-matter experts and managers on proposed legislative changes and the status of pending legislation that may have an impact on Company operations. The employee also creates and presents information on legislative and political activities for internal groups such as company senior management and internal subject matter experts. Generally speaking, the employee analyzes and evaluates complex utility issues and recommends strategies to minimize Company risks. In many cases this work may involve leading a team effort to develop work plans and complete policy analysis, and bringing recommended policies through internal review process. Through briefings and engagement with all related company departments, the employee ensures that Company decisions take into account local and regional policies as well as Company business interests.

Q. On April 29, 2024, about 10 days after it filed its Direct Testimony and as the Company was preparing its Reply Testimony due June 4, 2024, the Coalition served 66 data requests on the Company, 22 of which related to "Lobbying/Government Affairs." Five of those data requests, UG 490 Coalition DRs 276-277 and 290-292, sought job descriptions and other information about certain employees. How did the Company respond to those five data requests?

A. The Company's responses provided the requested information. Confidential NW Natural/3303-3304, Williams, are the requested job descriptions and other requested information related to members of the Government Affairs team. As

expected, the descriptions portray a mixture of core utility functions, with associated costs properly recovered from customers, as well as activities intended to influence a legislative body, with associated costs properly not recovered from customers. The job descriptions translate into many areas of core utility work performed by the Company's Government Affairs team, including:

- Developing, implementing and quality testing the General Procedure.
- Exception time reporting, in compliance with the General Procedure.
- Answering data requests in rate cases.
- Addressing operational issues as a conduit for community groups.
- Involvement in the Company's Incident Command Team on matters such as the impact of severe weather events on our customers, and related communication and coordination with other utilities regarding gas system resiliency and reliability during those events.
- Coordination with regional utility partners on efficiency and reliability commitments, especially during weather events.
- Working with local governments and their public works engineers on permitting processes.
- Safety issues, such as houseless encampments that are potentially dangerous to work crews and too close to utility infrastructure.
- Tracking various municipal planning efforts, such as right-of-way changes.
- Participation in low-income rate assistance efforts.

- Outreach to unhoused populations and representative community groups about Company projects that may impact them.
- Outreach to homeowners, renters, and businesses about Company projects that may impact them.
- Acting as conduits between Company departments and municipalities' economic development departments regarding gas service capacity to new residential, commercial and industrial developments.
- Communicating with customers and the general public about gas safety at community safety events.
- Participating in trainings (e.g., about the Company's Code of Conduct and safety-related matters).

Q. After taking into consideration all of the core utility functions performed by the Company's Government Affairs team, how much time did that team exception time report in 2023?

A. As I indicated earlier, it varied depending upon the member of the Government Affairs team. Exception time reported in 2023 for the Government Affairs team accounted for 51.1 percent, 38.2 percent, 34.3 percent, 30.7 percent, 26.5 percent, 22.7 percent, 7.3 percent and 4.3 percent of the various individuals' time.[39] As I noted earlier, while these percentages (and their associated dollar amounts) do provide snapshots of our lobbying and political activities that will vary significantly year to year, the exception time reporting under the General Procedure has

[39] NW Natural/3305, Williams (Company response to UG 490 Coalition DR 291).

provided us a higher level of confidence that we are and have been accurately reporting our lobbying and political activities to non-recoverable accounts.

Q. Do you have any further comments regarding the Company's General Procedure and use of exception time tracking?

A. The Coalition presumes bad faith by the Company in the Coalition's recommendation that, without "actual evidence" of positive time reporting, the Commission should assume that the Company's Governmental Affairs employees "are not" working at all on core utility functions. The implication that Company employees are falsifying their time sheets[40] is absurd and wholly unsupported. These are professionals whose actions – including exception time reporting – are governed by a Company Code of Conduct. The Coalition's "scorched-earth" tactic of proposing to disallow all costs of NW Natural's Government Affairs department flies in the face of the Commission's awareness in Order No. 22-388 (at page 24) that "some proportion of the department's work involves informational engagement and education for local governments for which ratepayer support is appropriate." As an officer of the Company, I personally have reviewed reports summarizing exception time reporting by our employees, I have had numerous discussions with our employees about their exception time reporting and the imperative that it be done so accurately and completely, and I have talked with key Company

[40] For example, the Coalition asserts that the Company "continues to evade attempts by the Commission and stakeholders to ensure the company does not charge ratepayers for its promotional and lobbying activities." Coalition/200, Apter-Connolly/58. The Coalition also calls on the Company "to ensure that the utility is not padding some of its expense since the Commission removed a portion of its government affairs budget in Order No. 22-388." Coalition/200, Apter-Connolly/69.

employees about my own exception time reporting. Based on my first-hand knowledge and careful review, I believe that our employees are appropriately exception time reporting their activities working on political activities/lobbying separate from their core functions.

Q. The Coalition also notes that that certain entries in the exception time reporting narratives are blank. How do you respond?

A. Yes, there are instances in which the "Notes" field in the exception time report is "blank."[41] While a blank description lacks detail that is required in our policy, it is not indicative of a lack of exception time tracking. Rather, it is evidence that employees did track their time (and specifically to the political activities cost center). As such, it should not be a factor in determining a disallowance to the Company's request. While the blank notes should have no bearing on cost recovery, we will continue to educate our employees about exception time reporting, review exception time entries and make adjustments as appropriate, and counsel our employees about such adjustments. To penalize the only utility in Oregon that is so robustly exception time reporting its lobbying activities to my knowledge, because of "blank" notes in exception time reports, by completely eliminating the cost of the Company's entire Government Affairs department would prevent the Company from being able to recover its legitimate and reasonable costs of providing utility service to our customers. It is my hope that the Commission acknowledges the Company's substantial efforts to comply with the

[41] Coalition/200, Apter-Connolly/58 and 65.

Commission's expectations,[42] recognizing that the Company commits to continuing to review and refine its General Policy and how our employees implement it.

Q. The Coalition's testimony references a single email from a Government Affairs employee to an employee of the City of Portland regarding a concert to support its assertion that the Company should also record non-exception time.[43] How do you respond?

A. As I have already explained at length, the Company disagrees with the Coalition's proposal to require the Company to track non-exception time. On occasion, the Company interacts with public officials in informal settings—such as lunch, coffee, or even a concert. Connecting outside of an office setting is common in the business world, and this particular communication regarding a concert does nothing to support the Coalition's case that the entire cost of the Company's Government Affairs department should be disallowed for recovery.

Q. Does this conclude your Reply Testimony?

A. Yes.

[42] *In re Northwest Natural Gas Co., dba NW Natural, Request for a General Rate Revision,* Docket No. UG 435, Order No. 22-388 at 23-24 (Oct. 24, 2022).

[43] Coalition/200, Apter-Connolly/68.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibits of Kathryn M. Williams

POLITICAL ACTIVITIES
EXHIBITS 3301 – 3305

REDACTED

June 4, 2024

EXHIBITS 3301-3305– POLITICAL ACTIVITIES

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Exhibit 3301 – UG 490 Coalition DR 145 NWN Response 1

Exhibit 3302 – Confidential UG 490 Coalition DR 145 Attachment 1 (Excel)

Exhibit 3303 – Confidential UG 490 DR 290 Attachment 4 1-5

Exhibit 3304 – Confidential Amended UG 490 Coalition DR 290 NWN Response

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Exhibit 3305 – Confidential UG 490 Coalition DR 291 NWN Response 1

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Kathryn M. Williams

POLITICAL ACTIVITIES
EXHIBIT 3301

June 4, 2024

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 Coalition DR 145

Referring to NW Natural/1200, Williams/Page 5–6, please provide all time reporting entries for employees logging exception time reporting.

Response:

Refer to Confidential UG 490 Coalition DR 145 Attachment 1 for the exception time reporting entries for all exception time for the employee groups referenced in NW Natural/1200 Williams.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Kathryn M. Williams

POLITICAL ACTIVITIES
EXHIBIT 3302

This confidential exhibit is being filed in its native, Excel format.
No redacted version exists.

June 4, 2024

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Kathryn M. Williams

POLITICAL ACTIVITIES
EXHIBIT 3303

REDACTED

Under the Commission's General Protective Order 23-132, this exhibit is confidential in its entirety and has been redacted.

June 4, 2024

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Kathryn M. Williams

POLITICAL ACTIVITIES
EXHIBIT 3304

REDACTED

Under the Commission's General Protective Order 23-132, this exhibit is confidential in its entirety and has been redacted.

June 4, 2024

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Kathryn M. Williams

POLITICAL ACTIVITIES
EXHIBIT 3305

REDACTED

Under the Commission's General Protective Order 23-132, this exhibit is confidential in its entirety and has been redacted.

June 4, 2024

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Reply Testimony of
Brody J. Wilson and Nikki R. Sparley

UNCOLLECTIBLE EXPENSE
EXHIBIT 3400

June 4, 2024

EXHIBIT 3400 – REPLY TESTIMONY – UNCOLLECTIBLE EXPENSE

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I. INTRODUCTION AND SUMMARY

Q. Are you the same Brody J. Wilson and Nikki R. Sparley who provided Direct Testimony on Northwest Natural Gas Company's dba NW Natural ("NW Natural" or "the Company") uncollectible expense?

A. Yes, we presented NW Natural/1300, Wilson-Sparley.

Q. Have you reviewed the Opening Testimony regarding the Company's uncollectible expense?

A. Yes, we reviewed the Opening Testimony of Public Utility Commission of Oregon Staff ("Staff") witness Charles Lockwood and Oregon Citizens' Utility Board ("CUB") witness John Garrett addressing the Company's uncollectible expense.

Q. Please summarize Staff's and CUB's Opening Testimony as it relates to the Company's uncollectible expense.

A. Staff and CUB both criticize NW Natural's forecast approach of taking the uncollectible rate from docket UG 435 and making several relevant and timely modifications to account for factors that the Company expects to affect the rate in the Test Year.[1] Staff criticizes each of the modifications the Company made to arrive at a forecasted uncollectible rate for the Test Year.[2] Staff proposes to calculate the uncollectible rate using a three-year historical average, which it claims is the Commission's long-standing policy,[3] and Staff proposes an

[1] NW Natural/1300, Wilson-Sparley/11-12.

[2] Staff/1200, Lockwood/5-17.

[3] Staff/1200, Lockwood/18-19.

approximately $2.8 million[4] decrease in expense to reflect an uncollectible rate of 0.182 percent.[5] CUB, on the other hand, recognizes that the three-year historical average may not be representative of the future.[6] While CUB specifically criticizes two of the Company's proposed modifications to forecast the uncollectible rate,[7] CUB does not propose a specific adjustment or calculation methodology.

Q. Please summarize your Reply Testimony.

A. NW Natural urges the Commission to adopt the uncollectible rate of 0.491 percent as proposed in our Direct Testimony because neither Staff nor CUB provide reliable data that demonstrate a lower amount is reasonable or any reason to ignore the current economic, regulatory, and policy environment affecting uncollectible amounts. First, the three-year historical average approach to calculating the uncollectible rate is not a long-standing Commission policy as Staff claims. Second, even if using a three-year historical average were the Commission's preferred policy, it should not be applied in this case because the historical period includes effects of the COVID-19 pandemic and several other significant changes, which will cause the uncollectible rate to remain higher than pre-pandemic levels and volatile over the next several years. Staff and CUB do

[4] Staff's Opening Testimony stated Staff's adjustment as $2.6 million. See Staff/1200, Lockwood/20. However, Staff confirmed in Staff Response to NW Natural Data Request No. 9, Exhibit NW Natural/3401, Wilson-Sparley, that this amount contained a typo and Staff's true recommended adjustment results in a $2.8 million decrease.

[5] Staff/1200, Lockwood/4, 19. As discussed later in this testimony, Staff's adjustment uses outdated numbers that the Company has since corrected.

[6] CUB/200, Garrett/5.

[7] CUB/200, Garrett/6-7.

not contest this point. Third, Staff's and CUB's criticisms of the factors the Company used to project the Test Year uncollectible rate are unfounded. Although they are necessarily estimates, the Company's projections are reasonable and consistent with data available to date.

Q. Do you include any exhibits with your testimony?

A. Yes, we are presenting the following exhibits: NW Natural/3401, Wilson-Sparley (Staff Response to NW Natural Data Request No. 9), and NW Natural/3402, Wilson-Sparley (NW Natural Response to CUB Data Request No. 14)[8].

Q. Before responding to Staff's and CUB's arguments, please provide an overview and update regarding the uncollectible rate data that will be discussed in your Reply Testimony.

A. The three-year historical average for the most recent three-year period from January 1, 2021 to December 31, 2023 is 0.220 percent.

As NW Natural explained in response to CUB Data Request 14 (NW Natural/3402,Wilson-Sparley), our Opening Testimony incorrectly reflected the rate for October 2020 to October 2022 (0.182 percent), not October 2021 to October 2023 (0.242 percent). The 0.220 percent figure provided above uses the more recent time frame (2021-2023) but relies upon updated information through December 2023 that was not available when we filed Direct Testimony. We note that Staff recommends using the three-year historical average for 2021 to 2023,

[8] The Attachment to this data request was provided as CUB/202, Garrett. Therefore, NW Natural provides only the narrative portion of the response in this exhibit.

which it states is 0.182 percent based on NW Natural's Direct Testimony,[9] but in light of the updated information provided above, we understand that Staff's recommended rate may be 0.220 percent.

In addition, CUB testifies that the Company's 2023 uncollectible rate was 0.284 percent,[10] which reflects the rate for January 1, 2023 to October 31, 2023. However, the uncollectible rate for January 1, 2023 through December 31, 2023 was 0.250 percent. The uncollectible rate for March 1, 2023 to March 31, 2024 is 0.260 percent, and we will provide another update with the most recent information available in our Surrebuttal Testimony.

II. RESPONSE TO STAFF AND CUB

Q. What is the basis for Staff's recommendation to use the three-year historical average?

A. Staff states that the Commission's "historic precedent" is to use a three-year historical average of the uncollectible rate.[11]

Q. Does CUB comment on the method for calculating the uncollectible rate?

A. Yes, CUB frames the three-year historical average as the Commission's "standard method," though it notes that effects of the pandemic may make this approach less reliable for the Test Year.[12]

[9] Staff/1200, Lockwood/19.

[10] CUB/200, Garrett/5.

[11] Staff/1200, Lockwood/18-19.

[12] CUB/200, Garrett/7.

Q. Do you agree that the three-year historical average is established Commission policy?

A. No, the Commission has not adopted a policy or standard method for calculating the uncollectible rate for a utility's revenue requirement, and our understanding is that there are no Commission orders or rules prescribing the method for the uncollectible expense. Staff provided four examples of uncollectible expense calculations in past utility rate cases.[13] However, as Staff acknowledges,[14] only two of the examples use a three-year historical average to calculate the uncollectible rate.[15] The other two examples rely on a four-year average and a two-year average.[16] Additionally, both of the Commission orders Staff cites as examples of a three-year historical average involved stipulations where the parties agreed to use the three-year historical average to calculate the uncollectible rate. But our understanding is that the Commission's orders adopting the stipulations do not indicate any intent to adopt the three-year historical average as the standard method to be used in all future rate cases. Therefore, we disagree with Staff and CUB that the three-year average is a "historic precedent" or "standard method" of the Commission.

[13] Staff/1200, Lockwood/3.

[14] Staff/1200, Lockwood/4.

[15] *In the Matter of Avista Corp.*, Docket No. UG 246, Order No. 14-015 at 2-3 (Jan. 21, 2014); *In the Matter of Avista Corp.*, Docket No. UG 186, Order No. 09-422, App. A at 4 (Oct. 26, 2009).

[16] *In the Matter of Idaho Power Co.*, Docket No. UE 167, Order No. 05-871, App. A at 4 (Jan. 28, 2005); *In the Matter of Cascade Nat. Gas Corp.*, Docket No. UG 287, Order No. 15-412, App. A at 2 (Dec. 28, 2015).

Q. Why does Staff contend that the three-year historical average is appropriate for this case?

A. Staff implies that the three-year average is reasonable for the Test Year because, historically, the three-year average "smooth[s] out year-over-year variances."[17]

Q. Does CUB agree that the three-year historical average is appropriate?

A. CUB states that the three-year historical average would be preferable to the Company's approach but questions whether it is representative of the future given the pandemic-related impacts during the period covered by the historical three-year average.[18]

Q. Why does NW Natural believe that the three-year historical average for the years 2021 to 2023 is not representative of the Test Year uncollectible rate?

A. As we explained in our Direct Testimony, this three-year period contains significant fluctuations in the economy due to the COVID-19 pandemic and regulatory and policy changes that are likely to have an effect on the uncollectible rate.[19] While the worst of the COVID-19 pandemic had subsided by 2023, there still exist lingering economic pressures that have pushed the 2023 uncollectible rate higher than the three-year historical average of 0.220 percent, resulting in a total uncollectible rate for 2023 of 0.250 percent.[20] In addition to these pressures on the economy, the Division 21 rule updates impact the way that overdue accounts

[17] Staff/1200, Lockwood/19.

[18] CUB/200, Garrett/7.

[19] NW Natural/1300, Wilson-Sparley/2-3.

[20] NW Natural/1300, Wilson-Sparley/3.

are handled, which supports the projection that the uncollectible rate will continue to increase.

Q. Staff indicates that the three-year historical average approach typically tracks the overall trend.[21] Is that the case for the years 2021 through 2023?

A. No. As we discussed earlier, the historical average (0.220 percent) is lower than both the actual rate for the 2023 calendar year (0.250 percent) and the rolling 12-month rate through March 2024 (0.260 percent). An historical average may produce an accurate projection when the uncollectible rate is stable year-to-year. However, as discussed throughout this testimony, there are multiple factors that have made the current uncollectible rate volatile and likely to remain that way, making Staff's three-year historical average approach unreliable for use in this case.

Q. Has the Company continued to witness the uncollectible rate increase?

A. Yes. The current 12-month average rate from March 1, 2023 to March 31, 2024 is 0.260, which is higher than the three-year historical average for January 1, 2021 through December 31, 2023 of 0.220 percent. Moreover, the uncollectible rate fluctuates over the course of the year, and NW Natural expects that the uncollectible rate will continue to climb as we get later into the year. Specifically, because NW Natural is a seasonal business, it receives higher revenue in the winter than in summer. However, accounts that become overdue are not written off as uncollectible until months later. Because the uncollectible rate is expressed

[21] Staff/1200, Lockwood/19.

as a percentage of revenue, the uncollectible rate begins to climb as the weather gets warmer and the Company's seasonal revenues begin to decrease. Due to this pattern, the current rolling 12-month uncollectible rate will almost certainly be higher than the current rate once winter uncollectible accounts are written off.

Q. Turning to NW Natural's proposal, what factors has the Company identified that are likely to affect the uncollectible rate?

A. In our Direct Testimony, we provided six modifications based on conditions we expect to affect the uncollectible rate that should be accounted for in forecasting the uncollectible rate for the Test Year.[22] Those modifications relate to lingering pandemic economic conditions, residential deposits, changes to the Division 21 rules and the collections process, and the end of the arrearage management program. Specifically, the Company proposes the following calculation:

Baseline Uncollectible Rate 2017-2019	0.097%
Weaker Economic Conditions	0.100%
Deposits No Longer Collected	0.137%
Division 21: Temperature/Weather/Wildfire/AQI/Shortened Day	0.029%
Division 21: Customer Notice Change 15 to 20 Days	0.007%
Collection Agency Reduced Recoveries	0.071%
Discontinued Arrearage Management Program	0.050%
	0.491%

[22] NW Natural/1300, Wilson-Sparley/12.

Q. Please summarize Staff's and CUB's testimony regarding the Company's proposed modifications to the uncollectible rate.

A. Staff took issue with each of the Company's six modifications. Specifically, Staff was unconvinced that economic conditions will lead to increasing uncollectible accounts.[23] Staff criticized the Company's modification relating to residential deposits, arguing that the Company had not demonstrated the connection between the end of collecting deposits and an increase in delinquent accounts.[24] Staff also argued that the Division 21 rules changes were made to increase customer protections, and Staff does not understand the Company's reasoning that these protections would cause an increase in uncollectible accounts.[25] Staff further criticized the Company's modification to the uncollectible rate based on the end of the arrearage management program.[26]

CUB critiqued two modifications: the Company's modification based on the Division 21 rules' increased notice period and the Company's modification based on lingering pandemic effects on the economy, but did not make a specific recommendation for the uncollectible rate.[27]

[23] Staff/1200, Lockwood/7.

[24] Staff/1200, Lockwood/9.

[25] Staff/1200, Lockwood/12.

[26] Staff/1200, Lockwood/15.

[27] CUB/200, Garrett/7.

A. Economic Conditions Modification

Q. Staff argued that while the economy is weaker, it "is not in a technical recession today," and Staff states the Company has not justified the economic impact modification to the uncollectible rate.[28] How do you respond?

A. While it is true that Oregon is not in a technical recession, we disagree with Staff that economic conditions do not justify a modification to the uncollectible rate. The Company reviewed economy recovery data for the region, and Oregon specifically, to determine that economic conditions in Oregon have not recovered as swiftly or as robustly as in other areas of the country or other parts of the Company's service territory. For example, Oregon has experienced two consecutive quarters of employment loss.[29] Oregon's unemployment rate in March 2024 was 4.2 percent.[30] This number is high relative to the U.S. as a whole, which was at 3.8 percent unemployment in March 2024.[31]

Further, data support concern surrounding Oregon's increasing unemployment insurance initial claims, declining exports, and depressed housing market suffering from limited sales activity, higher mortgage rates, and ongoing affordability issues. Oregon exports were down 19 percent through the 12 months

[28] Staff/1200, Lockwood/6-7.

[29] State of Oregon Employment Dept., *Oregon's Nonfarm Payroll Employment Rises by 4,900 in April* at 1, News (May 15, 2024) (available at https://www.qualityinfo.org/documents/20126/110739/Employment+in+Oregon/443acc10-b64a-e9d5-2f48-988e1e0d45df?version=1.141).

[30] *Id*.

[31] *Id*.

ending in February 2024, led by a decline of $3.4 billion in semiconductor exports, which made up approximately 32 percent of exports.[32] Of the 107 goods-exporting industries in Oregon, 64 percent saw exports decline over the past 12 months ending February 2024.[33] In addition, new listings of homes for sale and closed sales continue to decline in the first quarter of 2024 across Oregon and the Portland metro area, while total listing time on the market increased to about 90 days in both areas.[34]

Given the stagnation in opportunities and growth, Oregon has not fully recovered from the pandemic and continues to experience economic pressures in a variety of industries. Staff does not provide evidence to dispute the ongoing economic downturn experienced by Oregon residents, instead arguing that Oregon is not in a "technical recession today."[35] However, the data demonstrate that a significant number of Oregon industries are still plagued by a stagnated economy.

[32] U.S. Census Bureau Economic Indicators Division, U.S. Import and Export Merchandise trade statistics, USA Trade Online (accessed May 29, 2024).

[33] *Id*.

[34] RMLS, March 2024 Market Action Statistics, Real Talk with RMLS Ep. 81 (Apr. 17, 2024) (available at https://rmlscentral.com/podcast/march-2024-market-action-statistics-real-talk-with-rmls-episode-81/).

[35] Staff/1200, Lockwood/6.

Q. Staff additionally argues that the Company's economic conditions modification overstates the likely uncollectible rate because it relies on data from periods of more significant economic downturn such as 2001.[36] How do you respond?

A. The Company acknowledges that the current conditions are different from these previous periods of economic turmoil and that its modification is necessarily an approximation. That said, the Company believes its proposal is reasonable. However, even if the Company's modifications were overstated, the appropriate response would be to propose a lesser modification—not to make no modification to the forecasted uncollectible rate to reflect expected economic conditions. There is no dispute that economic conditions in the Test Year are likely to differ significantly from the economic conditions in 2017 to 2019, which is the period used to establish the baseline uncollectible rate.

Q. Does Staff raise any other concerns regarding the economic conditions modification?

A. Yes, Staff criticized the Company's process for calculating the 0.10 percent economic conditions modification.[37] Specifically, in our Direct Testimony, we explained that NW Natural found the average of uncollectible rates during recessions was 0.40 percent, which is 0.15 percent higher than uncollectible rates in non-recessionary periods.[38] The Company reasoned that if the economy were

[36] Staff/1200, Lockwood/8.

[37] Staff/1200, Lockwood/6-7.

[38] NW Natural/1300, Wilson-Sparley/12.

in a recession, it would expect to see rates in line with this average—that is, approximately 0.15 percent higher than non-recession years. However, because the economy is not in a technical recession though it is struggling, the Company did not apply the full 0.15 percent modification and instead adjusted this modification down to 0.10 percent.[39] Staff criticizes the Company's methodology stating that this modification "assumes conditions that raise the current uncollectible rate unrealistically."[40] Although Staff acknowledges the Company did not apply the full 0.15 percent but instead reduced the amount of this modification to 0.10 percent, Staff questions the Company's justification for this reduction.[41]

Q. How did the Company conclude the reduction from 0.15 percent to 0.10 percent was necessary?

A. The Company acknowledges that this calculation is necessarily an estimate to account for the present, unique economic environment. However, the Company determined that applying the full amount of the recession average was inappropriate given that we are not in a technical recession. The Company conservatively reduced the percentage by one-third to appropriately capture the likely rise in uncollectible rates due to economic pressures.

[39] NW Natural/1300, Wilson-Sparley/12-13.

[40] Staff/1200, Lockwood/8.

[41] Staff/1200, Lockwood/8-9.

Q. Regarding the economic conditions modification, CUB commented that while the Company's data indicate customers are having a harder time affording gas bills, the Company is seeking to increase rates for these customers.[42] How do you respond?

A. CUB does not appear to contest that economic conditions will lead to a higher uncollectible rate in the future. That said, the Company is aware that costs are rising for customers in many areas of daily life, energy costs included. The Company works to keep rates fair, just, and reasonable while also setting the uncollectible rate at a level that will allow the Company to meet its obligation to offer safe and reliable service at a time that its costs are also rising.

As indicated in the Direct Testimony of Cecelia Tanaka, NW Natural has prepared and continues to improve on its equity analysis.[43] NW Natural continues to analyze and review the tools available to help mitigate rate changes and energy burden, thus helping to insulate the impacts of rate changes on customers most in need.

[42] CUB/200, Garrett/7.

[43] NW Natural/200, Tanaka/12-13.

B. Deposits No Longer Collected Modification

Q. The Company included this modification to address the fact that the Company is no longer collecting deposits on any customer accounts.[44] Does Staff agree with the Company's modification?

A. No, Staff criticizes the Company's modification, stating that there is no evidence that the end of collecting deposits will affect the uncollectible rate.[45] Staff also questions the relationship between deposits and the uncollectible rate.[46]

Q. Please respond to Staff's request for clarification regarding how the deposit refunds on customers' closing bills relate to the uncollectible amount.[47]

A. The Company held deposits for certain customers and would credit the deposit back on a customer's account to lower the balance owing to the Company. As such, when a customer who had paid a deposit closed their account or was disconnected from service, the deposit would be credited back on their final bill. For example, if a customer had paid a $100 deposit but their final bill was $200, the deposit would be credited toward the final bill so the customer would owe a balance of only $100. If a customer was unable to pay that final bill, only the $100 that was not covered by the deposit and was still owed would be included in uncollectible amounts.

[44] NW Natural/1300, Wilson-Sparley/13-14.

[45] Staff/1200, Lockwood/9.

[46] Staff/1200, Lockwood/9-10.

[47] Staff/1200, Lockwood/9-10.

Q. Staff argues that there is no evidence that halting deposits will lead to an increase in uncollectible amounts.[48] Why does the Company expect that no longer collecting deposits will increase uncollectible amounts?

A. Because the deposits that would have been applied to reduce customers' closing balances are no longer available, customers will have higher account balances when sent a final bill, and the full amount of that final bill, if unpaid, would be included in uncollectible amounts instead of only the portion not covered by the deposit credit. Because the Company is no longer collecting deposit amounts up front, the uncollectible amounts are likely to be higher.

Without deposits to apply to offset overdue accounts, the Company expects the uncollectible rate to continue rising as it has observed in recent years. For example, over the past three years, the Company has observed a steady increase in amounts ultimately written off. In 2021, the Company wrote off $2.3 million; in 2022, it wrote off $2.5 million, and in 2023, it wrote off $3.5 million. The Company expects this write-off amount to continue increasing in 2024 and beyond.

Q. Staff argues NW Natural's deposit adder modification fails to account for new customer protections that are aimed at alleviating residential customers' energy burden.[49] How do you respond?

A. NW Natural does not expect other customer protections to decrease the level of write-offs. In fact, the Company's experience demonstrates that since the

[48] Staff/1200, Lockwood/9-10.

[49] Staff/1200, Lockwood/10.

adoption of Division 21 additional customer protections, write-offs have increased rather than decreased.

C. Division 21 Rule Change Resulting in Shortened Service Days Modification

Q. Staff criticizes the Company's premise that fewer service days will increase the uncollectible rate and argues that the Division 21 rule changes are likely to lower the number of customer disconnections.[50] How do you respond?

A. While the updated Division 21 rules may lead to fewer disconnections, disconnections do not equal uncollectible amounts. As discussed in detail below, although disconnections may happen less frequently under the new Division 21 rules, a customer is likely to have a higher balance when experiencing disconnection than under the prior rules, likely leading to higher uncollectible amounts.

Q. The Company indicated in its Direct Testimony that the Division 21 rule changes decrease the amount of field orders it can complete due to restrictions on timing and weather conditions.[51] What are "field orders"?

A. When the Company discusses "field orders," it refers to field technicians sent out to a customer's residence to collect overdue amounts or disconnect the gas service. Field technicians provide a final line of communication with a customer in arrears. They can also help the customer trouble-shoot issues or connect them with additional assistance, providing personal help for individual issues. Field

[50] Staff/1200, Lockwood/12.

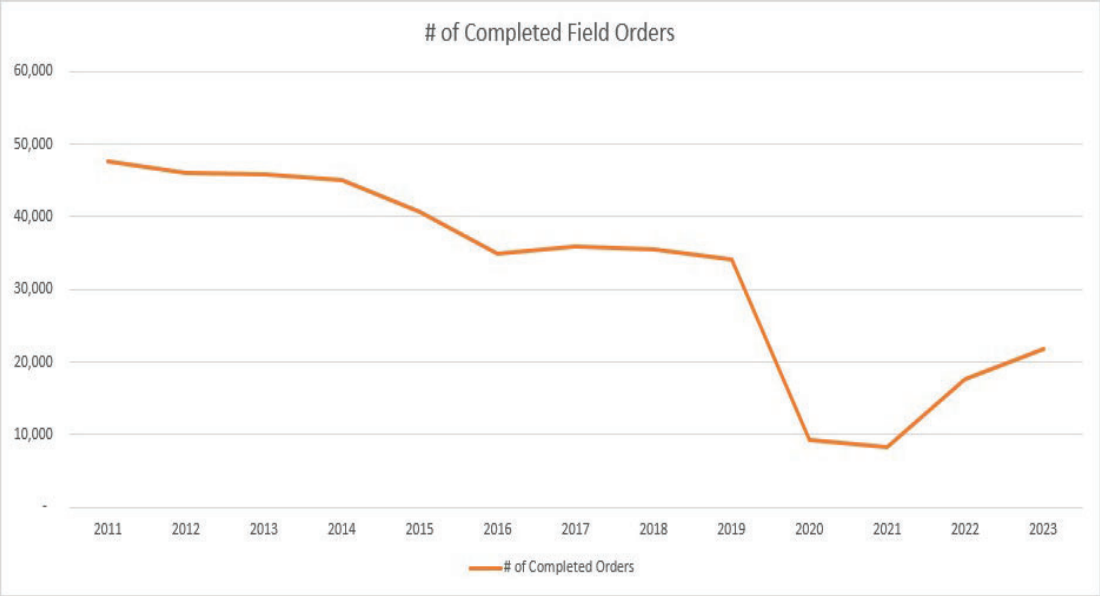
[51] NW Natural/1300, Wilson-Sparley/14-15.

orders must be completed timely to address arrearages but also to avoid a customer's overdue balance spiraling out of control, because the longer a customer is allowed to continue using gas service without payment, the more likely that the account will become uncollectible.

Q. How have the rule changes affected the number of field orders the Company can complete in a year?

A. The Company is able to complete significantly fewer field orders in a year. As depicted below in Figure 1, prior to the pandemic, the Company averaged approximately 36,000 field orders completed per year. The Company was unable to complete many field orders at all during the pandemic, dipping below 10,000 completed orders in 2020 and 2021, as reflected in Figure 1. However, once the Company resumed field orders, the completed field order number should have returned to pre-pandemic levels. But, after the Division 21 rules affecting field order hours took effect in late 2022, the Company was only able to complete 22,000 field orders in 2023. The Company will continue to function under a reduced number of hours within which to complete field orders; therefore, it is likely that the number of completed field orders will remain suppressed and similar to 2023 numbers.

Figure 1



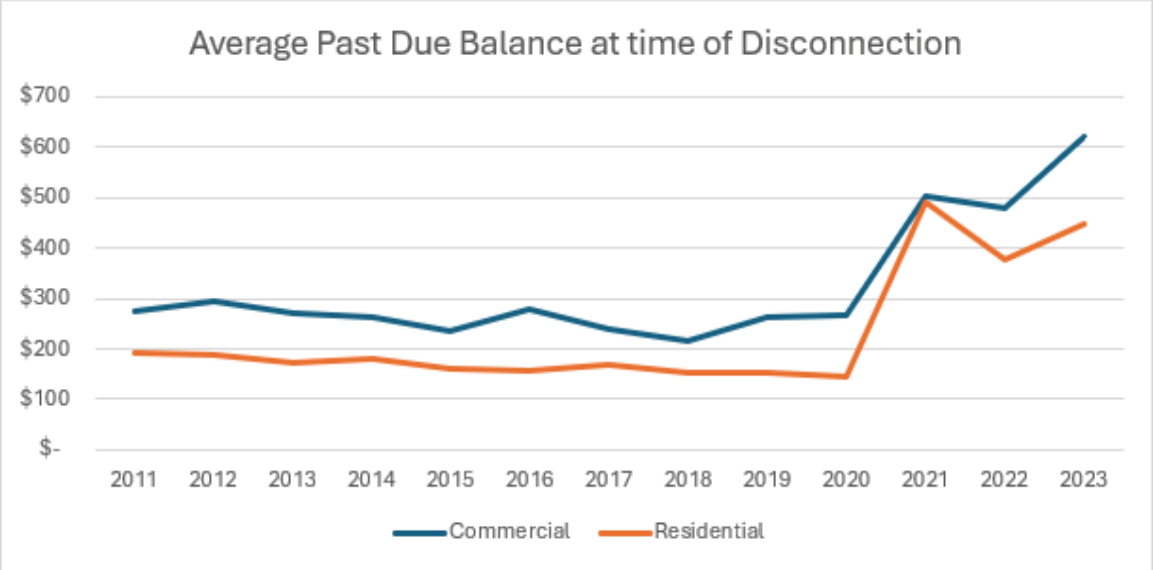
Q. What trends has the Company observed in customer bills when performing field orders before and after the rule changes?

A. Because the Company is completing fewer field orders due to the rule changes, field technicians are unable to reach a customer until their balance is much higher than in prior, comparable years. As a result, the amount that the field technician is going out to collect is averaging approximately double the average prior to the Division 21 rule changes.

As is illustrated in Figure 2 below, prior to the Division 21 rule changes, the average overdue balance for a residential customer facing disconnection by field technicians was approximately $200, where a commercial customer had an average overdue balance of $400 with no outlier months where the average overdue amount was over $400. This trend remained steady for nearly a decade.

However, post-pandemic, the Company is seeing both residential and commercial customers' overdue balances skyrocket before a field order to disconnect the customer can be completed, with the highest monthly average residential balances reaching approximately $800 and commercial monthly average balances over $1,000. While disconnections can prompt customers to pay, customers whose balances have ballooned will have a harder time making payments in full. Accordingly, the increase in customer balances is likely to lead to increased uncollectible amounts than would have occurred under the prior rules.

Figure 2[52]



[52] As discussed below and in our Direct Testimony, the Arrearage Management Program reduced the amounts customers owed from May 2021 when NW Natural started giving out grants and through 2022 when the program ended. *See* NW Natural/1300, Wilson-Sparley/17.

Q. Staff additionally criticizes the Company's modification for shortened field order days, arguing it "assumes that all customers will accrue balances uniformly."[53] How do you respond?

A. While the Company agrees that customers do not typically accrue balances uniformly, the Company believes it is reasonable to assume balances accrue uniformly for the purposes of a projection calculation.

D. Division 21 Rule Change Resulting in Customer Notices Extending from 15 to 20 Days Modification

Q. Please summarize the Company's modification based on the Division 21 rule change that extends customer notice periods.

A. In our Direct Testimony, the Company describes how the Division 21 rules increased notice time to customers for any service interruptions from 15 to 20 days.[54] To comply with this change, the Company had to remove its courtesy three-day call ahead that contacted customers three days prior to service disconnection due to an overdue balance.[55] The Company still provides a courtesy call one day prior to disconnection.[56] The Company expects that the elimination of the three-day call ahead will increase uncollectible amounts, because any customer that would have responded to that call with a payment will not have the same opportunity to do so.[57]

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[53] Staff/1200, Lockwood/12.

[54] NW Natural/1300, Wilson-Sparley/15-16.

[55] NW Natural/1300, Wilson-Sparley/15.

[56] NW Natural/1300, Wilson-Sparley/15-16.

[57] NW Natural/1300, Wilson-Sparley/15-16.

Q. Do Staff or CUB agree with this modification?

A. No. Staff argues it is unclear how the Division 21 rule change resulted in the Company's removal of the three-day call ahead and expected increase in uncollectible amounts.[58] Staff also questions whether the Company has evidence to show this rule change has increased the uncollectible rate to date.[59] CUB also appears to contest this modification.[60]

Q. How do you respond?

A. The three-day call ahead provided one more touchpoint with the customer to collect on the account. The Company observed the three-day call ahead generated up to 20 percent of payments of customers who carried past-due balances. The Company expects that it will not see this same level of payment toward overdue balances in the future.

Q. Why did the Company remove the three-day call ahead to customers?

A. The Company was required to change its billing and collections processes to conform to changes in the Division 21 rules. In order to convert its system to work within the new rules, the Company had to remove the three-day call ahead. The Company was unable to take a different approach, such as changing the entire collections system to implement shortened timing, due to the high cost and disruptive nature of such a project. These costs would have ultimately been borne

[58] Staff/1200, Lockwood/13.

[59] Staff/1200, Lockwood/13.

[60] CUB/200, Garrett/6-7. CUB reiterates the Company's reasoning for this modification but does not provide any argument or clear criticism.

by customers. After careful consideration, the Company determined that removing the three-day call-ahead was the most efficient way to comply with the Division 21 rules, despite the impact on the uncollectible amount.

Q. Is it reasonable to conclude that without this three-day call ahead, the Company will not receive payments on overdue accounts that it would have received with the three-day call ahead?

A. Yes, and this conclusion serves as the basis of the need for this modification to the uncollectible calculation.

E. Collection Agency Reduced Recoveries Modification

Q. Please summarize Staff's testimony regarding the Company's proposed modification to the uncollectible rate based on reduced collection agency recovery rates.

A. Staff questioned the Company's proposed methodology that accounts for changes in the Consumer Financial Protection Bureau Regulation F, effective as of November 30, 2021, that permits a consumer to have more control over how collection agencies communicate with them and creates new restrictions on collection activities.[61] Staff notes that the Company provided collection rate data from 2014-2019 compared to the past two years after this regulatory change became effective and questions whether two years of data are sufficient to establish a trend.[62]

[61] Staff/1200, Lockwood/14.

[62] Staff/1200, Lockwood/14.

Q. How do you respond to Staff's argument that two years of data on collection agency recoveries is not sufficient to establish a trend for purposes of increasing the uncollectible rate?[63]

A. We disagree. Staff acknowledges that the collections recovery rate has decreased and does not dispute the Company's data showing that collection efforts have become significantly less effective in the past two years.

F. Discontinued Arrearage Management Program Modification

Q. Staff criticized the Company's modification due to the end of the Arrearage Management Program ("AMP"), arguing that the pandemic economic conditions that made the AMP necessary have subsided.[64] How do you respond?

A. As discussed above, Oregon is still experiencing economic effects and has been slower to rebound than many other areas of the country. Therefore, it is reasonable to conclude that Oregon customers will see higher unpaid balances in the absence of the AMP.

Q. How many grants did the Company give to customers through the AMP and how did those grants affect overdue balances?

A. Through the AMP, NW Natural gave out 41,478 grants to customers totaling $9,077,994. The over $9 million in grants was provided as an instant credit on these customers' accounts, reducing their balance and helping them avoid

[63] Staff/1200, Lockwood/15.

[64] Staff/1200, Lockwood/16.

disconnection. Without these funds, customers' balances that remained unpaid would have become uncollectible and written off by the Company.

Q. Did some customers who benefitted from AMP nevertheless have overdue balances?

A. Yes. While the AMP was able to assist a significant number of customers, 25.73 percent of AMP grant recipients fell into arrears that ended up being written off as part of the uncollectible amounts after receiving an AMP grant. As discussed in our Direct Testimony, with the help of the AMP, NW Natural was able to reduce its uncollectible expense but still wrote off $4,704,000 between May 2021 through December 2022.[65] Of those write-offs, $1.2 million were associated with accounts that received AMP funds. It is reasonable to assume that in the absence of the AMP, these customers—and others who received benefits—will continue to have overdue balances. Therefore, the Company's modification to account for discontinuance of the AMP is reasonable.

Q. Staff criticized the Company's lack of discussion of the bill discount program and its effect on the uncollectible rate.[66] Has the Company considered how the changes to the bill discount program proposed in this rate case will affect the uncollectible rate?

A. Yes. Currently, approximately 5 percent of our total customer count is enrolled in the bill discount program. Of that 5 percent of customers, only 5.21 percent of bill

[65] NW Natural/1300, Wilson-Sparley/18.

[66] Staff/1200, Lockwood/18.

discount program participants have been written off to bad debt. This is approximately 0.3 percent of NW Natural's total customer base, or approximately 2,600 customers. Because this number is such a small percentage, the bill discount program is unlikely to make a material difference in our write-off numbers.

Q. Does this conclude your Reply Testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibits of Brody J. Wilson and Nikki R. Sparley

UNCOLLECTIBLE EXPENSE EXHIBITS 3401 – 3402

June 4, 2024

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Exhibit 3402 – UG 490 NWN Response to CUB DR 14 1

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Brody J. Wilson and Nikki R. Sparley

UNCOLLECTIBLE EXPENSE EXHIBIT 3401

June 4, 2024

Date: May 9, 2024

TO:

Eric Nelsen
Northwest Natural Gas
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FROM: Charles Lockwood, Staff

OREGON PUBLIC UTILITY COMMISSION
Docket No. UG 490 – NWN Data Request No 09.

Data Request No 09:
Referring to Staff/1200, Lockwood/20, line 3 and /29, Line 9. Please state whether "$2.6 million" or "$2.8 million" is the correct amount.

Staff Response No 09:

Staff's proposed downward adjustment of the Company's proposed uncollectible rate from 0.491 percent to 0.182 percent, is accompanied by a downward adjustment of approximately $2.8 million ($2,825,682,82) to the Company's Test Year expense. Staff appreciates the Company finding the typo of "$2.6 million" on Staff/1200, Lockwood/20, Line 3 and confirms that $2.8 million is the correct amount.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Brody J. Wilson and Nikki R. Sparley

UNCOLLECTIBLE EXPENSE EXHIBIT 3402

June 4, 2024

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 CUB DR 14

On NW Natural/1300/Wilson-Sparley/Page 18, regarding uncollectible expense, the Company states "The three-year historical average rate for years October 2021 through October 2023 is 0.182 percent, which is much lower than the rate the Company has observed in 2023…"

a. Please provide workpapers for the Company's calculation of the "three-year historical average rate for years October 2021 through October 2023" in USD.

b. Please provide workpapers for the Company's calculation of "the rate the Company has observed in 2023" in USD.

Response:

Please see UG 490 CUB DR 14 Attachment 1.

After reviewing this data request and the cited testimony, the Company has determined that there is a typographical error in the testimony. The three-year historical average rate of 0.182 percent is for the three years "October 2020 through October 2022," not October 2021 through October 2023. The Company will correct the testimony for the record during the pendency of this proceeding. For the three-year period October 2021 through October 2023, the three-year historical average rate was 0.242 percent, which is lower than the 0.284 percent that the Company experience in October 2023.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Reply Testimony of Tobin F. Davilla

OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES EXHIBIT 3500

REDACTED

June 4, 2024

EXHIBIT 3500 – REPLY TESTIMONY – OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES

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I. INTRODUCTION AND SUMMARY

Q. Are you the same Tobin F. Davilla who filed Direct Testimony in this proceeding on behalf of Northwest Natural Gas Company dba NW Natural ("NW Natural" or the "Company")?

A. Yes, I presented NW Natural/1400, Davilla.

Q. What is the purpose of your Reply Testimony in this proceeding?

A. The purpose of my Reply Testimony is to respond to testimony filed on April 18, 2024, by the Public Utility Commission of Oregon ("Commission") Staff ("Staff"), the Alliance of Western Energy Consumers ("AWEC"), and the Coalition of Communities of Color, Climate Solutions, Verde, Columbia Riverkeeper, Oregon Environmental Council, Community Energy Project and Sierra Club ("Coalition") related to operations and maintenance ("O&M") expenses. I will respond to issues presented in the testimony of Staff witnesses Luz Mondragon (Staff/200, Mondragon), David Abraham (Staff/500, Abraham), Russ Beitzel (Staff/700, Beitzel), Julie Dyck (Staff/1000, Dyck), Mitchell Moore (Staff/1300, Moore) and Paul Rossow (Staff/1700, Rossow); AWEC witness Bradley G. Mullins (AWEC/100, Mullins); and Coalition witnesses Nora Apter and Meredith Connolly (Coalition/200, Apter-Connolly).

Q. Please summarize your Reply Testimony.

A. In my testimony, I respond to proposed disallowances and concerns raised by Staff, AWEC, and Coalition on the following issues:

O&M Expenditures and Forecasts

- *Non-Payroll O&M Escalation Method:* In response to staff witnesses Abraham, Mondragon, Dyck, Rossow, and Moore, I explain that NW Natural more accurately projects the majority of non-payroll O&M costs using the West Region Consumer Price Index ("CPI"), as this inflation index most accurately reflects the costs experienced by the Company. If the Commission accepts Staff's use of the All-Urban CPI rates, those rates should be updated for the most recent June 2024 Oregon Economic and Revenue Forecast rates of 3.3 percent and 2.2 percent for 2024 and 2025, respectively.
- *Directors and Officers ("D&O") Insurance:* In response to both Staff witness Mr. Beitzel and AWEC witness Mr. Mullins, I explain that the Company's allocation of D&O insurance policy premiums is appropriate, as these expenses protect the Company's financial stability and ensure that the Company can continue to reliably serve customers. Further, I discuss Staff's misinterpretation of the Commission's previous ruling regarding primary versus excess layers.
- *Storage Operating Expense (FERC 816-847)*: In response to Staff witness Mr. Abraham, I explain that his calculation of Test Year expense based on historical results does not accurately capture the inflation impact and that relying on historical results in this FERC account is not a good basis for the Test Year projection. In addition, I explain why his additional adjustment for CPI is duplicative based on his use of the revised CPI rate to inflate Staff's recommended historical average amount to the Test Year.

- *A&G Expense (FERC 921, 922, 930 & 931):* In response to Staff witness Ms. Dyck, I discuss the adjustment for revised inflation rates and explain why I do not agree with a proposed 50/50 sharing of expenses related to Corporate Secretary and Director Expenses.
- *Distribution O&M (FERC 870-894):* In response to Staff witness Mr. Moore, I explain that his calculation of Test Year expense based on historical results does not accurately capture the current expense for this work, nor does it fully capture the impact of additional mandated United States Department of Transportation Pipeline and Hazardous Materials Safety Administration survey work that began in 2023. In addition, the contract is known and measurable because it has specified prices for services and annual increases into the Test Year, which are not factored into Staff's analysis. Finally, Staff witness Mr. Moore's calculation disregards the increase in number of locates that the Company has been experiencing historically and expects through the Test Year.
- *Customer Accounts (FERC 901-903):* In response to Staff witness Mr. Moore, I explain how his calculation of Test Year expense based on historical results does not accurately capture the current expense for this work, nor does it capture the impact of greater customer adoption of the Payment Processing service that has been growing near 13 percent per year over the past five years and is projected to continue to grow by 10 percent per year. Mr. Moore's calculation disregards the impact of the new contract for this service that is known and measurable. Finally, Mr. Moore's opening testimony, which argues

that the Company should not use services like Venmo and PayPal, does not take into account that unbanked customers utilize services like Venmo and PayPal to pay their gas bills.

- *Meals & Entertainment and Misc. O&M Expenses:* In response to Staff witness Mr. Rossow, I explain for each expense category why they are appropriate for recovery and agree that the first-class airfare costs inadvertently included in this case should be excluded from cost recovery.
- *Dues and Memberships Expenses:* In response to Staff witness Mr. Rossow and Coalition witnesses Ms. Apter and Ms. Connolly, I explain that the Company's dues and memberships expenses are a necessary portion of the Company's business expenses, as many memberships provide educational opportunities, increase industry engagement, and support and engage local communities.
- *Board of Directors' Fees and Related Expenses:* In response to AWEC witness Mr. Mullins, I explain that Board of Directors' fees are an essential cost of doing business, and time spent on non-utility or affiliate concerns has already been excluded from the Company's cost recovery request. In addition, I explain that AWEC offers no evidence beyond speculation that the Board of Directors is more concerned with furthering the interests of shareholders than benefiting customers, or that the Board of Directors' fees are not reasonable.

- *Water Insurance:* In response to AWEC witness Mr. Mullins, I explain that all insurance expense for NW Natural Water Company, LLC ("NW Natural Water") and its water utility subsidiaries already has been excluded from this case.
- *NW Natural Water Expenses:* In response to AWEC witness Mr. Mullins, I agree that the expenses found should have been removed from the case and agree with removing the quantified amount; however, I explain that any additional adjustment beyond what has been identified is unfounded.
- *Legal Fees:* In response to Coalition witnesses Ms. Apter and Ms. Connolly, I explain that the Company (i) has documented that it does not seek in the case to recover from Oregon ratepayers the legal fees of Baker Botts or Snell & Wilmer associated with NW Natural's legal challenge to the invalidated Climate Protection Plan ("CPP"), (ii) is removing $48,539 of legal fees related to the Climate Commitment Act ("CCA") and Washington State Building Code Council's ("SBCC") amendments to the building codes, after the Company discovered that they had been inadvertently included in this case to recover from Oregon ratepayers, and (iii) **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. Do you sponsor any exhibits to your Reply Testimony?

A. Yes. I sponsor the following exhibits:

- Confidential NW Natural/3501, Davilla (Company's Confidential UG 490 OPUC DR 224 Attachment 1)
- NW Natural/3502, Davilla (Company's Response to UG 490 OPUC DR 404)
- Confidential NW Natural/3503, Davilla (Company's Confidential UG 490 OPUC DR 404 Attachment 2)
- Confidential NW Natural/3504, Davilla (Company's Confidential UG 490 OPUC DR 404 Attachment 1)
- NW Natural/3505, Davilla (Company's UG 490 OPUC DR 201 Attachment 3)
- NW Natural/3506, Davilla (Company's Supplemental Response to UG 490 OPUC DR 201)
- Exhibit NW Natural/3507, Davilla (Company's Amended Confidential UG 490 DR 224 Attachment 1)
- NW Natural/3508, Davilla (Company's Supplemental Response to UG 490 OPUC DR 224)
- NW Natural/3509, Davilla (Company's Response and Supplemental Response to UG 490 AWEC DR 23, including its Attachment 1)
- NW Natural/3510, Davilla (Company's Response and Supplemental Response to UG 490 AWEC DR 24)
- NW Natural/3511, Davilla (Company's Response to UG 490 Coalition DR 219)
- NW Natural/3512, Davilla (workable version of UG 490 – Exh. 1400 – OM Model Workpaper-Non-Confidential)
- NW Natural/3513 (modified version of Coalition/226, Apter-Connolly)

- Confidential NW Natural/3514, Davilla (Company's Response to UG 490 Coalition DR 220)
- NW Natural/3515, Davilla (Company's Amended Response to UG 490 Coalition DR 218)

II. OPERATIONS & MAINTENANCE EXPENSE

A. Non-Payroll O&M Escalation Method

Q. When the Company used a CPI escalation method to forecast Test Year non-payroll O&M expenses, which CPI did the Company use?

A. As explained in my Direct Testimony, the Company generally escalated non-payroll costs using year-over-year increases reflected in the West Region Urban CPI, as reported in the September 2023 Oregon Economic and Revenue Forecast, published by the Oregon Office of Economic Analysis ("OEA").[1] The Company specifically selected the West Region Urban CPI because a regional CPI provides a better measure of aggregate price changes than a national CPI.[2]

Q. Does Staff agree that the Company should use the West Region Urban CPI to escalate O&M expenses?

A. No. Staff witnesses Abraham, Mondragon, Dyck, Rossow, and Moore would apply the Consumer Price Index – All Urban -Consumers for the U.S. ("All-Urban CPI"), as published by the OEA, for year-over-year escalation of expenses.[3] Additionally,

[1] NW Natural/1403, Davilla/54.

[2] NW Natural/1400, Davilla/9.

[3] Staff/200, Mondragon/15; Staff/500, Abraham/3-4; Staff/1000, Dyck/24-25; Staff/1300, Moore/10; Staff/1700, Rossow/12, 15.

they propose using the most recent release (then, the March 2024 report) of the All-Urban CPI for 2024 and 2025.

Q. How do the rates recommended by Staff compare to those filed by the Company in this case?

A. The All-Urban CPI rates recommended by Staff for 2024 and 2025 are 2.7 percent and 2.0 percent. This compares to the West Region CPI rate in the March 2024 report for 2024 and 2025 of 2.7 percent and 2.1 percent, respectively.

Q. Has there been a more recent release of the CPI since Staff's testimony, and, if so, how do those rates compare?

A. Yes, the June 2024 report was released on May 29, 2024. The All-Urban CPI rates increased from 2.7 percent and 2.1 percent in 2024 and 2025 in the March 2024 report to 3.3 percent and 2.2 percent, respectively, in the June 2024 report. The West Region rates by comparison increased to 3.4 percent and 2.3 percent for 2024 and 2025, respectively, in the June 2024 report.

Q. Does Staff explain why it uses the All-Urban CPI for the escalation factor rather than the West Region Urban CPI?

A. Yes. Staff witness Dyck states that "[i]t is Staff policy to use the Consumer Price Index – All Urban Consumers for the U.S. (CPI, Urban U.S.) as published by the State of Oregon Office of Economic Analysis for year over year escalation."[4] Staff witness Abraham states "Staff recommends using the all-urban CPI."[5]

[4] Staff/1000, Dyck/24.

[5] Staff/500, Abraham/4.

Q. Do you agree with these statements by Staff?

A. No. As explained in my Direct Testimony, a regional CPI provides a better measure of aggregate price changes experienced by the Company than the national CPI proposed by Staff because the Company's non-payroll expenses (e.g., utilities, repairs and maintenance, contractors, professional services) are largely regional expenses generated in Oregon or southwest Washington.[6] Therefore, national price fluctuations will be less representative of the price changes experienced by the Company than the West Region Urban CPI.

Q. Are Oregon-specific cost changes reflected in the All-Urban CPI?

A. Yes, but to a much lesser extent than in the West Region Urban CPI. Oregon's economy differs from national trends in areas that directly impact the Company's costs, such as wages, property, and fuel. For example, compared to all other U.S. states, Oregon has the fifth highest gasoline prices,[7] the sixth highest minimum wage,[8] and the eighth highest median home price.[9] All of these costs result in increased prices for non-payroll items.

The combined impact of these cost increases can also be seen through Oregon's relative cost-of-living index, shown below for 2023.[10]

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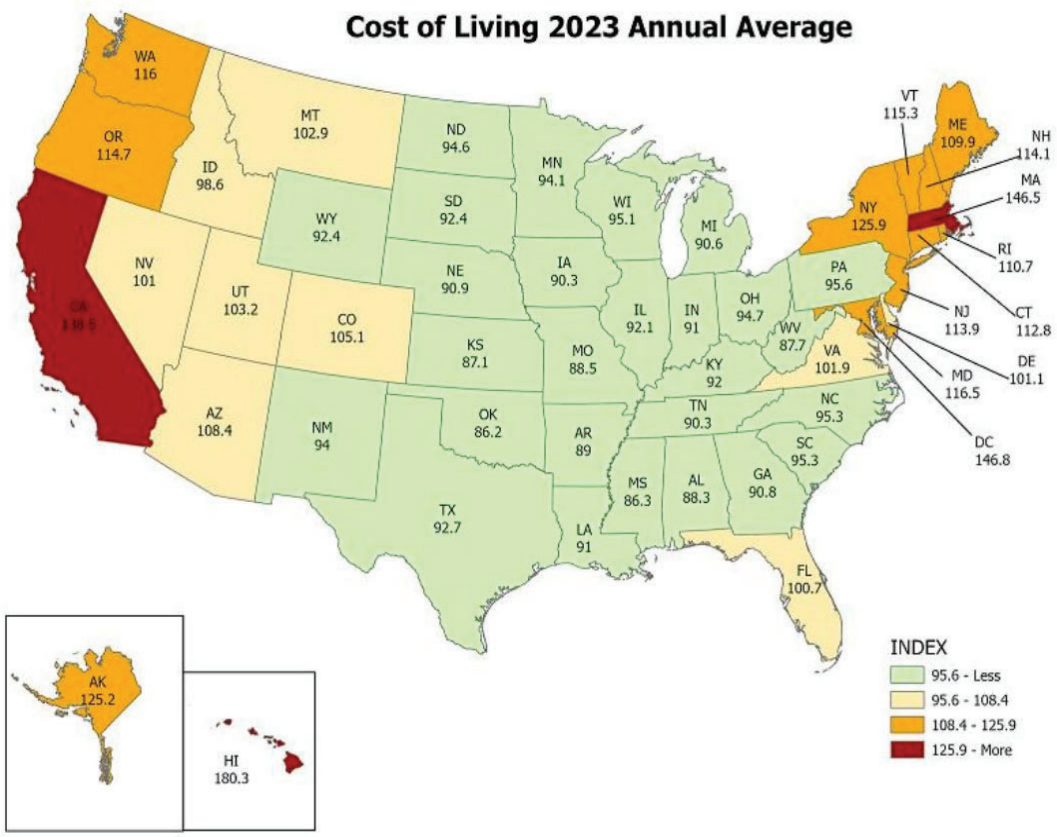
[6] NW Natural/1400, Davilla/9.

[7] AAA, *State Gas Price Averages* (accessed May 6, 2024) (available at https://gasprices.aaa.com/state-gas-price-averages/) (comparing regular gas prices by state).

[8] U.S. Dept. of Labor, *State Minimum Wage Laws* (Jan. 1, 2024) (accessed May 6, 2024) (available at: https://www.dol.gov/agencies/whd/mw-consolidated) (comparing minimum wage by state).

[9] Wikipedia, *List of U.S. states by median home price* (2024) (accessed May 6, 2024) (available at: https://en.wikipedia.org/wiki/List_of_U.S._states_by_median_home_price).

[10] Missouri Economic Research and Information Center, *Cost of Living Data Series* (accessed May 6, 2024) (available at: https://meric.mo.gov/data/cost-living-data-series).



The cost-of-living index allows for a state-by-state comparison of the overall cost of goods and services. The states that make up the West Region Urban CPI have an average cost of living index of 113.8. This compares similarly to the Oregon index of 114.7 and is much closer than the national average of 100. In sum, the All-Urban CPI fails to adequately capture Oregon's greater inflationary pressure, which results in greater inflation of the Company's costs.

Q. Do other entities that operate in Oregon use the West Region Urban CPI to escalate costs?

A. Yes. The Oregon Public Employees Retirement System ("PERS") uses the West Region Urban CPI to ensure that retirees' income keeps pace with the rising prices they experience.[11]

Q. Does Staff propose an adjustment related to the CPI?

A. Yes. Staff witnesses Abraham, Mondragon, Dyck, Rossow and Moore all make adjustments for the lower CPI or use the lower CPI in their determination of Test Year expenses.

Q. Does the Company propose any changes to CPI as compared to the original rate that was filed in this case?

A. No. The West Region Urban CPI is a more representative rate for the reasons mentioned above. However, if the Commission accepts Staff's use of the All-Urban CPI, this rate should be updated for the most recent report (June 2024).

B. D&O Insurance

Q. What is D&O insurance and why is it included in the Company's cost recovery request?

A. D&O insurance protects the Company's directors and senior officers against the risks associated with managing the Company. These risks are an inherent part of managing and overseeing a utility or other company and are a necessary cost to

[11] Oregon Public Employees Retirement System, *2024 Cost-of-Living Increase Coming in August* (accessed May 6, 2024) (available at: https://www.oregon.gov/pers/ret/pages/cost-of-living-adjustment.aspx).

ensure that the Company remains financially secure and capable of serving NW Natural's customers. NW Natural's Test Year D&O, Crime and Travel Accident insurance premiums were $805 thousand[12] on an Oregon-allocated basis.

Q. How does Staff propose adjusting the Company's recovery of D&O insurance premiums?

A. Staff witness Mr. Beitzel proposes that 50 percent of the excess D&O liability insurance costs be disallowed, citing past Commission practice. This approach, according to Staff's calculation, would result in a downward adjustment of $403 thousand.[13]

Q. Does any other party recommend adjusting the Company's recovery of D&O insurance premiums?

A. Yes, AWEC witness Mr. Mullins proposes D&O insurance premiums also be split 50/50 between shareholders and ratepayers. He proposes an adjustment to reduce O&M by $374 thousand.[14] His proposed O&M reduction is different than Staff's $403 thousand.

Q. Does the Company agree with Staff's and AWEC's calculations of their proposed adjustments?

A. No. The Company's response to UG 490 OPUC DR 224 – Confidential Attachment 1 (Confidential NW Natural/3501, Davilla) combines both D&O and

[12] Confidential NW Natural/3501, Davilla (Confidential UG 490 OPUC DR 224 Attachment 1).

[13] Staff/700, Beitzel/6.

[14] AWEC/100, Mullins/40.

Crime and Travel Accident premiums. The $805 thousand in the Test Year is comprised of $760 thousand for D&O and $45 thousand for Crime and Travel Accidents. In addition, the $760 thousand D&O Insurance is comprised of $465 thousand for the Primary layer and $295 thousand of Excess layers.

Q. Does the Company agree with Staff's and AWEC's proposed adjustment of a 50/50 sharing?

A. No. While Staff states "Staff has routinely recommended removal of 50 percent of Excess D&O liability insurance as a shareholder cost,"[15] that is not what Staff performed as its adjustment. Instead of sharing on the "Excess" layers, Staff proposes a 50/50 sharing on all D&O liability insurance. In UE 197, Staff Witnesses Ball-Dougherty proposed the 50 percent sharing of excess D&O liability and specifically stated: "The excess insurance should be considered a joint shareholder/customer cost. It is important to note that Staff did not recommend any adjustments to the primary D&O insurance costs. The 50 percent reduction in excess D&O liability insurance cost only represents 32.3 percent of the total D&O liability insurance."[16] The Commission agreed with Staff's adjustment related to the excess layers being shared.[17]

[15] Staff/700, Beitzel/5.

[16] *In re Portland Gen. Electric Co., Request for a General Rate Revision,* Docket No. UE 197, Staff/300, Ball-Dougherty/10-11 (Jul. 9, 2008).

[17] *In re Portland Gen. Electric Co., Request for a General Rate Revision,* Docket No. UE 197, Order No. 09-020 at 19-20 (Jan. 22, 2009).

Q. What would have been Staff's proposed adjustment had the 50/50 sharing been applied only to the Excess D&O liability insurance as approved by the Commission in UE 197?

A. The adjustment that should have been proposed by Staff is $147.5 thousand,[18] instead of the $403 thousand in Staff's testimony, to share 50/50 on the excess layers.

Q. Does the Company agree with any proposed adjustment to its Excess D&O liability insurance?

A. No. While the Company recognizes that the Commission has previously supported sharing the excess cost of D&O insurance in an earlier Portland General Electric Company ("PGE") rate case, such cost sharing inappropriately assumes that customers receive only partial benefit from such expense. Notably, Staff and AWEC do not contest that D&O insurance is a necessary cost of doing business and is therefore a prudently incurred expense.[19] Indeed, these costs help ensure the Company's financial stability and continued ability to serve customers. Moreover, NW Natural has already removed D&O liability expenses allocated to non-utility business units, meaning that the remaining amounts are those solely dedicated to the regulated utility's stability and security. Thus, these remaining utility-allocated costs are prudently incurred and should be fully recovered in rates.

[18] $295,000 x 0.50 = $147,500.

[19] Staff/700, Beitzel/5-6; AWEC/100, Mullins/39-40.

C. Storage Operating Expense (FERC 816-847)

Q. Please describe the costs included in FERC Accounts 816-847.

A. The expenses occurring in FERC Accounts 816-847 are related to the Company's underground and Liquid Natural Gas ("LNG") storage facilities. The storage facilities allow the Company to store lower summer-priced natural gas to be used in the winter during high demand or peak day events.

Q. Please describe how the Company developed the non-payroll Storage Operating Expense in the Test Year.

A. To get to the Test Year expense, the Company performed two calculations. First, the Base Year expenses were escalated into the Test Year using the West-Region CPI. Secondly, beginning in 2024 (i.e., after the Base Year), the Company will begin its first rig-based casing inspection program to perform re-assessments in accordance with 49 CFR 192.12(d)(2). This will be an on-going expense beginning in 2024. The total expense is $625 thousand, and the Oregon allocated amount is $556 thousand. That Oregon allocated amount was added to the Test Year amount.

Q. How does Staff review these expenses?

A. Staff witness Mr. Abraham analyzed historical data provided by the Company and looked for trends in the expenses.

Q. Does Staff propose an adjustment to these FERC accounts?

A. Yes, Staff proposed a total downward adjustment of $210,320. This amount is made up of an expense reduction of $130,504 to align to Staff's calculated

historical trend and a downward adjustment of $79,816 to account for the lower CPI forecast.[20]

Q. How does Staff witness Mr. Abraham calculate his proposed Test Year amount?

A. First, Staff calculates a three-year moving average for the years 2021 through 2023 and uses that amount for the projected 2024 expense. To calculate the Test Year amount, Staff takes the increase in the moving average for 2021 through 2023 as compared to 2020 through 2022 and adds that to the projected 2024 expense to develop Staff's Test Year amount prior to any adjustments. Staff then adds in the $556 thousand incremental amount for the rig-based inspection program beginning in 2024. Staff then compares that projected Test Year amount to the Company's proposed amount. This produced an adjustment of $130,504. Second, Staff calculates the change in the Company's Test Year amount using Staff's proposed CPI rates of 2.7 percent in 2024 and 2.0 percent in 2025 instead of the Company's CPI rates as filed. This produced an additional downward adjustment to expense of $79,816.[21]

Q. Do you agree with Staff's calculation of its Storage Expense (FERC 816-847) disallowance?

A. No. I do not agree with Staff's calculation for two reasons. First, Staff uses a simple average of 2021 through 2023 for its 2024 value. Staff's calculation

[20] Staff/500, Abraham/7-8.

[21] Staff/500, Abraham/5-8.

disregards CPI increases of 8.0 percent in 2022 and 4.1 percent in 2023. Second, Staff's additional CPI adjustment of $79,816 is duplicative to and already captured in Staff's $130,504 adjustment. Staff's historical trend analysis calculates Staff's proposed Test Year expense for Storage Expenses, and it arrives at that amount by using the lower Staff-recommended CPI rates. The $130,504 adjustment, therefore, already includes the reduction for CPI.

Q. Do you agree with any adjustment to Storage Expense?

A. No, however, if the Commission accepts Staff's use of the All Urban-CPI rates, the Commission should use the most recent release of the CPI published in the June 2024 report. The impact of this change would result in a reduction to Storage Expense of $43,087. I do not agree with the other Staff adjustment to Storage Expense for $130,504. As stated above, $79,816 of that amount is duplicative and the remaining $50,688 adjustment is not warranted because expenses four years removed from the Test Year that do not include an inflation adjustment during a period of significant inflationary pressure (12.4 percent, 2022-2023) are less representative of costs than those the Company actually experienced in the Base Year 2023.

D. Customer Service Expense (FERC 907-916)

Q. Please describe the costs included in FERC Accounts 907-916.

A. The expenses occurring in FERC Accounts 907-916 are related to Customer Service and Informational activities.

Q. Please describe how the Company developed the Customer Service Expense in the Test Year.

A. To determine the Test Year expense, the Company escalated the Base Year expenses into the Test Year using the West-Region CPI rates at the time of filing.

Q. How does Staff review these expenses?

A. Staff witness Ms. Mondragon reviews Base Year expenses including transactional level data.[22] In addition, Staff reviews historical data for trends, variances, average and growth. Staff's review excluded FERC 909 Informational and Instructional Advertising Expense and 913 Advertising Expense of which the latter expenses were not included in this case.[23]

Q. Does Staff propose an adjustment to these FERC accounts?

A. Yes, Staff proposes an adjustment of $108,457 system or $95,858 Oregon allocated adjustment.[24] In addition, Staff proposes an adjustment of $5,810 to account for Staff's proposed updated CPI adjustments.[25] The Company addresses the first Staff adjustment in the Reply Testimony of Mr. John Frankel, NW Natural/4300, Frankel. I will address the second Staff adjustment.

[22] Staff/200, Mondragon/9-11.

[23] Staff/200, Mondragon/8-15.

[24] Staff/200, Mondragon/14.

[25] Staff/200, Mondragon/15.

Q. How do you respond to Staff's proposed adjustment of $5,810 to account for Staff's proposed updated CPI adjustments?

A. As I stated earlier in my Reply Testimony, if the Commission accepts Staff's proposed All-Urban CPI rates, the Commission should use the most recent release of the All-Urban CPI published in the June 2024 report. The impact of this change would result in a reduction to Customer Service Expense of $3,827.

E. A&G Expenses (FERC 921, 922, 930 & 931)

Q. Please describe the costs included in FERC Accounts 921, 922, 930 & 931.

A. The expenses occurring in these FERC accounts include Administrative and General Salaries and Office Supplies and Expenses (FERC 921), Administrative Expenses Transferred-Credit (FERC 922), Misc. General Expenses (FERC 930), and Rent (FERC 931).

Q. How does Staff review these expenses?

A. Staff witness Ms. Dyck reviews expenses for reasonableness and appropriate use.[26] Staff reviews sections of the Company's application, reviewed responses to Standard and Staff DRs and analyzes corresponding transactional data including review of historical trends and proposed escalation adjustments.[27]

Q. Does Staff propose an adjustment to these FERC accounts?

A. Yes, Staff proposes a total adjustment of $865,046 Oregon allocated adjustment.[28] This adjustment is made up of an adjustment of $652,794 for the lower proposed

[26] Staff/1000, Dyck/23.

[27] Staff/1000, Dyck/25.

[28] Staff/1000, Dyck/30.

CPI rate and an adjustment of $212,252 for sharing 50/50 of specific expenses occurring in FERC 930 related to Corporate Secretary Misc Expense Director Fees and Expense.[29]

Q. How does Staff calculate the proposed Test Year amount?

A. Staff takes all the expenses occurring in this cost center for Directors Fees and Expenses that were not covered by other Staff adjustments and recommends sharing 50/50 these expenses. Staff does not specifically state why these expenses in particular should be shared, but states they follow guidance in relation to "Directors and Officers (D&O) liability insurance, meals, entertainment, gifts, airfare, travel, lodging, awards, office refreshments, catering, promotional items, and bonuses and incentives."[30]

Q. How do you respond to Staff's calculation and adjustment to A&G expenses?

A. As I stated earlier in my Reply Testimony, if the Commission accepts Staff's proposed All-Urban CPI rates, the Commission should use the most recent release of the All-Urban CPI published in the June 2024 report. The impact of this change would result in a reduction to A&G Expense of $350,432.

I disagree with Staff's additional proposed 50/50 expense sharing adjustment of $212,252. While Staff lists in its testimony those expenses that they typical propose sharing of, many of the costs included in this adjustment do not fit

[29] Staff/1000, Dyck/29-31.

[30] Staff/1000, Dyck/29 (footnotes omitted).

that typical description. For example, $130,796 of that $212,252 adjustment is for Professional Services expenses for consultants who continually review compensation or for subscription costs to Diligent, which is a software used to support governance, risk, compliance, audit and ESG (Environmental Social and Governance). Such expenses are a necessary expense for the Company and therefore should not be disallowed.

F. Distribution O&M (FERC 870-894)

Q. Please describe the costs included in FERC Accounts 870-894.

A. The expenses occurring in these FERC accounts mainly include expenses and activities related to locating and survey expenses, system operations, customer field services, engineering, and compliance. The bulk (60 percent) of non-payroll expenses occur as a result of our locating and survey/leakage contract.

Q. Please describe how the Company developed the non-payroll Distribution O&M Expense in the Test Year.

A. For all but the Company's locate and survey work, the Company used the Base Year and escalated that using the West Region CPI rate to get to the Test Year amounts. For the Company's locate and surveying work, the Company included costs for the new contract for locating services and survey work that were not captured in the Base Year expenses. The costs in the Test Year also reflect the increasing number of locates being performed.[31]

[31] NW Natural/1400, Davilla/11-12.

Q. Did the Company provide the contract in its Opening Testimony?

A. Yes. The contract can be found at Confidential NW Natural/1406, Davilla.

Q. How does Staff review these expenses?

A. Staff witness Mr. Moore reviews historical expenses and looks at trends, transactional details and adjustments proposed by the Company.[32] Staff also reviews Company's responses to Staff Data Requests focused on investigating the Company's new locating and survey contracts with Heath Services.[33]

Q. Does Staff propose an adjustment to these FERC accounts?

A. Yes, Staff proposes an adjustment of $6.2 million.[34]

Q. How does Staff calculate the proposed Test Year amount?

A. First, Staff calculated a three-year moving average for the years 2021 through 2023 and used that number as the 2023 expense. Staff then escalates that number to 2024 and 2025 by Staff proposed CPI rate of 2.7 percent and 2.0 percent. Staff then compared that projected Test Year amount to the Company's proposed amount. This produced a disallowance of $6.2 million.[35]

[32] Staff/1300, Moore/3.

[33] Staff/1300, Moore/4.

[34] Staff/1300, Moore/5.

[35] Staff/1300, Moore/4-5.

Q. Does Staff acknowledge that there is a new contract beginning September 1, 2023 impacting the Test Year?

A. Yes, in Staff testimony Mr. Moore noted the Company conducted a request for procurement ("RFP") in late 2022 and the Company has provided the contract.[36] However, Staff "does not believe the Company has substantiated the reasonableness of the extreme increase in the cost of survey and locate rates."[37] Therefore, Staff disregards the impact of the new contract, and instead recommends only using a three-year average of expenses escalated for inflation for their Test Year amount.[38] Staff states that "[t]he increase in the Test Year expense over CPI inflation is almost entirely a result of the increase in NW Natural's contract locating and survey rates."[39]

Q. Can you explain the RFP process and the criteria that was evaluated in selecting this vendor for this required service?

A. An RFP process was completed in conjunction with procurement procedures as NW Natural's locating and leakage contracts were ending December 31, 2023. The RFP process was started in the fourth quarter of 2022 and completed in the first quarter of 2023 to allow time for a transition if it were determined that we were switching contractors with either locating or leakage. Six companies responded to the RFP: Heath, **[BEGIN CONFIDENTIAL]** [redacted]

[36] Staff/1300, Moore/5.

[37] Staff/1300, Moore/5.

[38] Staff/1300, Moore/5.

[39] Staff/1300, Moore/4.

[redacted] **[END CONFIDENTIAL]**. Only four companies met all the requirements and completed the documentation of the initial RFP: Heath, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** was removed because they chose not to bid on leakage and only bid on the locating portion of the RFP. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** was removed as they were determined early on that they did not have the resources to complete a contract this large. They are a small locating vendor that at the time only had 20 vehicles and approximately the same number of employees and did not have the financial backing to expand to meet NW Natural's needs.

The RFP was submitted to all companies for response. Companies were identified based on services offered, history with other utilities and ability to perform. Each company submitted a statement of work ("SOW") for the services. All questions from each company were responded to in a group setting or questions submitted individually by companies and then identical answers submitted to the entire group. Along with the SOW, companies were required to answer questions and were scored based on their answers, safety scores, along with pricing for both leakage and locating.

Q. Why was Heath selected?

A. The questionnaire had all remaining companies relatively even with two companies scoring slightly lower than the rest. Heath was significantly less expensive than all other companies when looking at leakage services. When looking at locating

services per individual price they were the most expensive, but when volume was factored in with the highest volume being standard distribution locates, Heath was the second least expensive. There were serious concerns over whether the lowest priced company could scale up to handle the contract and whether the cost was actually feasible as they were significantly lower than all others including our current contract.

Q. What other criteria were important in the selection of Heath for locating and survey work?

A. We evaluate all bidders in ISN, an independent safety scoring system. Three of the top 4 bidders were "As" with one being an "F." Heath Consultants was ranked as an A and the lowest priced vendor was ranked with a failing grade of F.

In addition, when checking with our peers across the industry, Heath was a more known contractor. We did not have many peers that had done a lot of work with the lowest priced vendor. They are used in the area by a telecommunications utility and in the last couple of years there have been reported issues with on-time locates mostly due to maintaining personnel and hiring employees. Heath is used by several gas utility companies along the West Coast and came highly regarded by our peers in the American Gas Association. Their strengths noted by other utility companies included their ability to hire, retain, and train employees and their management's ability to respond to and fix problems and ability to maintain an excellent company culture. Finally, Heath Consultants is a diverse supplier as a registered woman-owned company whereas the lowest priced vendor is majority-

owned by an investment firm. Choosing Heath was in line with our diversity, equity and inclusion goals.

When evaluating all four RFP bidders, Heath was clearly the leading candidate. They out competed all companies in leakage prices, out competed all but one company in locating prices by volume, were significantly higher than the next closest bidder by safety metrics, had great peer reviews, improved NW Natural's diverse spend goals, and had a proven track record working with NW Natural on prior contracts.

Q. Do you agree with Staff's calculation of its Distribution O&M disallowance?

A. No. I disagree with Staff for multiple reasons. First, the contract for Locates and Surveys was competitively bid through an RFP process as explained above. The resulting costs from the contract are market costs for this type of work. Second, Staff's proposal of a disallowance of locating and survey expenses appears to encourage lower safety standards or incentivize the Company to propose reduced calls for locates. We should be doing the opposite of this and promoting calling 8-1-1 before digging as "Research has revealed that if someone calls 8-1-1 before they dig, they have a 99 percent chance of avoiding an incident, injury, harm to the environment and even death".[40] Third, Staff uses a simple average of 2021 through 2023 for its 2023 value. Staff acknowledges and uses CPI; however, it does not apply it to the 2021 and 2022 historical expenses to bring the historical

[40] U.S. Dept. of Transp., *811 Day* (Aug. 11, 2022) (available at https://www.phmsa.dot.gov/safety-awareness/811-day).

amounts up to 2023 dollars. In doing so, Staff's calculation disregards CPI increases of 8.0 percent in 2022 and 4.1 percent in 2023. Fourth, using historical averages excludes additional work being performed to inspect the Company's Business District annually per U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration ("PHMSA") regulation 192.723(b). This additional expense was included in the Company's last rate case UG 435.[41] In UG 435, the additional expense, which began in 2023, was an Oregon-allocated amount of $1.4 million. Staff's methodology of averaging with periods prior to that regulation does not include this incremental work. Fifth, beyond the initial rate increase for locates that took effect in 2023, the contract calls for a 3 percent increase in rates annually. Staff's methodology would assume annual increases in rates below that of the contract (2.7 percent in 2024 and 2.0 percent in 2025). Finally, Staff disregards the annual increase in calls for locates that the Company has been experiencing and is expected to increase by 1.5 percent annually through the Test Year.

Staff's Test Year amount being proposed using its methodology would leave the Company well short of the expense in the Test Year; in fact, Staff's proposed Test Year amount is $1.3 million lower than the Base Year expense in this case. It is unrealistic to believe that the expense for locates and survey work will be lower than the expenses experienced in the Base Year, especially when including

[41] Docket No. UG 435, NW Natural/1200, Davilla/Page 13 (Dec. 17, 2021).

expected increase in number of locates and impacts of a new contract that began near the end of the Base Year.

G. Customer Accounts (FERC 901-903)

Q. Please describe the costs included in FERC Accounts 901-903.

A. The expenses occurring in these FERC accounts include expenses and activities related to customer records and collection expense.

Q. Please describe how the Company developed the non-payroll Customer Accounts Expense in the Test Year.

A. The Company used the Base Year forecast and escalated that using the West Region CPI rate to get to the Test Year amounts. In addition, the Company included additional expense for a new agreement with Paymentus for Customer Payment Processing Fees that was executed in December 2023 and greater adoption of the service.[42]

Q. Please explain the process of amending the agreement with Paymentus.

A. Before extending the current contract, competitive pricing was received from two other processors that provide bankcard processing services. The pricing of each of those other two processors was greater than our current and selected processor. Vendor A's proposal was approximately 39 percent more expensive and Vendor B's proposal was approximately 47 percent more expensive. Please see the Company's response to UG 490 OPUC DR 404 (NW Natural/3502,

[42] NW Natural/1400, Davilla/11.

Davilla), specifically Confidential UG 490 OPUC DR 404 Attachment 2 (Confidential NW Natural/3503, Davilla) for a comparison of those proposals.

Q. How does Staff review these expenses?

A. In Confidential UG 490 OPUC DR 404 Attachment 1, the Company provided the amended Paymentus contract that was made effective in December 2023, attached to my testimony as Confidential NW Natural/3504, Davilla. Staff witness Mr. Moore reviews this contract and also reviews previous cases where "Staff has recognized that it is reasonable to make payment options available to customers to ensure customers have convenient methods to pay their bills."[43] In addition, Staff also acknowledges that "given the importance of accessibility to payment options, Staff has supported spreading the costs of these payment options to all customers rather than requiring that the individual customers that use these options pay for them at the time of use."[44]

Q. Does Staff still believe spreading the costs to all customers is appropriate?

A. Staff states that the Company has a responsibility to communicate to its customers the various methods of payment, and if customers choose options that are less reasonably priced, the costs should not be spread to other customers.[45]

Q. Does Staff propose an adjustment to these FERC accounts?

A. Yes, Staff proposes an adjustment of $2.1 million.[46]

[43] Staff/1300, Moore/10.

[44] Staff/1300, Moore/10.

[45] Staff/1300, Moore/10.

[46] Staff/1300, Moore/11.

Q. How does Staff calculate the proposed Test Year amount and adjustment?

A. First, Staff calculates a three-year moving average for the years 2021 through 2023 and uses that number as the 2023 expense. Staff then escalates that number to 2024 and 2025 by Staff proposed CPI rate of 2.7 percent and 2.0 percent. Staff then compares that projected Test Year amount to the Company's proposed amount. This produced a disallowance of $2.1 million. Staff does not include any adjustment for the impact of the new contract.[47]

Q. Does Staff state why they are not including the impact of the new contract?

A. No, Staff only mentions that their calculation of the Test Year accounts for an increase in payment processing costs and incentivizes the Company to encourage lower-cost payment options.[48]

Q. Staff mentions "more expensive" payment options.[49] Can you describe those?

A. Staff mentions the advanced payment options of Amazon Pay, PayPal and Venmo to be the more expensive options,[50] however from April 2023 through March 2024 the average expense per transaction for these payment options were $0.0328 higher than the other payment options. When this is applied to the 20,366 payments made via these channels the additional expense is $668/month.

[47] Staff/1300, Moore/10.

[48] Staff/1300, Moore/10-11.

[49] Staff/1300, Moore/10-11.

[50] Staff/1300, Moore/10-11.

Q. Why is it important for the Company to provide those payment options?

A. Mobile payment applications are frequently used by both younger customers and those without bank accounts. Excluding advanced payment options would limit non-banked households' ability to pay. According to the FDIC,

> While many banked households appear to use nonbank online payment services such as PayPal, Venmo, and Cash App to complement banking products, unbanked households may be using them as substitutes for banking or other financial services. These use cases have different economic inclusion implications but highlight that it is important for all consumers to understand limits and applicability of consumer protections, especially deposit insurance.[51]

Q. In your Direct Testimony you state that the Company has also experienced an increase in the adoption of customers utilizing this service.[52] Does Staff consider this increase in their Test Year calculation?

A. No, when Staff performs their three-year historical average and then only a CPI adjustment it does not consider the impact of increased adoption by customers. Currently over 280,000 customers use this service per month. There has been a seismic shift from paying bills via check to electronic methods in the last 10 years alone. In 2013, 32.9 percent of payments were checks sent by mail. In 2023, only 13.9 percent of payments were checks sent in the mail. For the last five years the Company has experienced a year over year average increase of approximately 13 percent per year in the count of debit, credit card, and advanced payment method payments. This is a result of both annual customer growth, but mostly driven by

[51] FDIC, *2021 FDIC National Survey of Unbanked and Underbanked Households* (Jul. 24, 2023) (available at https://www.fdic.gov/analysis/household-survey/index.html).

[52] NW Natural/1400, Davilla/11.

increased adoption of existing customers. The Company is utilizing a 10 percent annual growth rate from the Base Year to the Test Year in this case. See Table 1 below for annual historic adoption growth.

Table 1

Year	Count Increase
2019	14%
2020	19%
2021	11%
2022	12%
2023	10%

Q. Do you agree with Staff's calculation of its Customer Accounts disallowance?

A. No, for multiple reasons. First, Staff uses a simple average of 2021 through 2023 for its 2023 value. Staff acknowledges and uses CPI; however, they do not apply it to historical values to calculate their simple average to bring the historical numbers up to 2023 dollars. Staff's calculation disregards CPI increases of 8.0 percent in 2022 and 4.1 percent in 2023. Second, Staff's methodology dismisses or severely negates the impact of the high rate of annual adoption. It averages it out when taking the three-year average and does not apply any impact of adoption when grossing up the 2023 average amount to the Test Year. Third, Staff disregards completely the impact of the new contract, which is known and measurable.

Staff's Test Year amount being proposed using their methodology would leave the Company well short of the expense in the Test Year, in fact Staff's proposed Test Year amount is lower than the actual expense the Company

incurred in 2022. It is unrealistic to believe that the expense for this service will be lower than the expenses incurred in 2022 let alone the Base Year, especially when including customers' strong desire for this service as evidenced by the increase adoption of this service.

Q. Do you agree with Staff's statement that their "forecast methodology accounts for an increase in payment processing costs and incentivizes the Company to encourage lower-cost payment options, while still allowing for more expensive options such as Amazon Pay, PayPal, and Venmo to be available to customers"[53]?

A. I do not agree with that statement and cannot reconcile how suggesting that having lower Test Year expense than the Company has experienced the last two years, which was prior to the effect of the new contract, would somehow allow for an increase in payment processing costs or encourage lower-cost payment options or even allow for more expensive options to be available to customers. As stated above the "more expensive" options equate to roughly $668/month. The $8,016 annual expense is a far distance from Staff's proposed $2.1 million disallowance. It is clear the proposed disallowance is not supported by the idea that the advanced payment options are the reason for the disallowance.

[53] Staff/1300, Moore/10.

Q. Do you believe any adjustment to Customer Accounts (FERC 901-903) is warranted?

A. No. The Company's proposed Test Year expense is based on the Base Year expenses grossed up by CPI and includes the incremental impact of the new Paymentus contract effective December 2023 and the impact of the annual increase in customer adoption of this service. However, as I stated earlier in my Reply Testimony, if the Commission accepts Staff's proposed All-Urban CPI rates, the Commission should use the most recent release of the All-Urban CPI published in the June 2024 report. The impact of this change would result in a reduction to Customer Accounts Expense of $46,433.

H. Meals and Entertainment, Awards, Gifts, Airfare, Lodging, and Travel Expenses

Q. What is included in this category of expenses being disallowed that Staff reviewed?

A. Staff witness Mr. Rossow utilizes the Company's response to SDR 57, Data Request Nos. 442-455, and Data Request No. 201 Attachment 3, to review meals and entertainment, awards, gifts, refreshments, airfare, lodging and travel type expenses.[54]

Q. How did Staff review and analyze these categories of expenses?

A. Staff witness Rossow reviews the Company's responses to data request to identify any "O&M non-payroll discretionary expenses that appear to be excessive or not

[54] Staff/1700, Rossow/14-15.

related to the provision of safe and reliable energy to customers."[55] Staff reviews transactions and expenditure types mentioned above following a Commission-approved cost sharing from a previous PGE rate case that recommends expenses that benefit both customers and shareholders should be shared 50/50, and expenses found to have no benefit to customers should be excluded 100 percent.[56]

In this case, for Meals and Entertainment, Employee Awards, Gifts, Lodging and Travel, Staff proposes 50 percent sharing of all the expenses.[57] For other selected expenditure types that Staff noted related to expenses for first class airfare, Staff recommends excluding those expenses at 100 percent.[58]

Q. What is Staff's recommendation regarding these expenses?

A. Staff recommends reducing the Company's Test Year expenses for these combined categories of expenses by $351,069.[59]

Q. Does the Company believe that meals, entertainment, refreshment, awards, lodging and gifts should be shared on a 50/50 basis?

A. No. While the Company recognizes that the Commission approved cost sharing in a prior PGE rate case, the Company continues to believe that these prudently incurred costs should be fully recoverable in rates.

[55] Staff/1700, Rossow/15.

[56] Staff/1700, Rossow/14-15.

[57] Staff/1700, Rossow/16.

[58] Staff/1700, Rossow/15-16.

[59] Staff/1700, Rossow/16.

Q. Please explain why employee awards and gifts should be fully recoverable.

A. Staff witness Rossow proposes excluding $85 thousand of employee awards and gifts from the O&M Test Year. Employee awards should be fully recoverable because they are an important part of how NW Natural attracts, motivates, and retains qualified workers. Qualified workers help ensure a safe and reliable system, resolving customer concerns and providing prompt and high-quality service. Moreover, retaining such qualified workers reduces the costs associated with finding and hiring new employees. Thus, by fostering a positive business culture for the Company, awards are prudently incurred and should be fully recoverable in rates.

Q. Please explain why refreshments and meals expenses should be fully recoverable.

A. Staff witness Rossow proposes excluding $207 thousand of refreshments and meals and entertainment expenses from the O&M Test Year.[60] Refreshments and meals expenses for employees are prudently incurred and should be fully recoverable because those costs are incurred for business purposes. For instance, both refreshments and meals provided to employees during working meetings increase efficiency and ensure that the Company can achieve more in a shorter time period—thereby benefitting customers. While the Company could attempt to avoid scheduling meetings that run over mealtimes, this would reduce efficiency.

[60] Staff/1704, Rossow.

Similarly, NW Natural provides meals expenses for employees traveling on business for NW Natural. Work-related travel is customary in the business world, as is reimbursement for the reasonable cost of meals necessitated by this travel. As a result, this compensation is an essential aspect of the Company's total compensation policies. The travel related expenses benefit Oregon ratepayers as they relate directly to traveling for work or conferences, where employees expand their knowledge about topics such as safety, security and operational best practices, learn about new trends and share experiences with their peers in collaborative settings.

Q. Please explain why lodging should be fully recoverable.

A. Staff witness Rossow proposes a disallowance of $18 thousand for costs associated with the NW Natural Leadership Meeting.[61] This disallowance includes lodging and meals during the retreat. This retreat focuses on developing leadership skills as well as used for critical discussions about industry topics.

Q. Please explain Staff witness Rossow disallowance for inadvertent airfare.

A. In response to Data Request No. 447, the Company revealed that it inadvertently included first class airfare totaling a Base Year amount of $36,257 resulting in a Test Year adjustment of $37,981.[62] I agree that an adjustment to remove $38 thousand is appropriate.

[61] Staff/1700, Rossow/16.

[62] Staff/1700, Rossow/16.

I. Dues and Membership Expenses

Q. What is included in the Company's expense category for dues and memberships?

A. The expense category for dues and memberships includes dues paid to organizations where membership is necessary for the Company and its employees for perform their job functions (e.g., the Oregon State Bar and Oregon Board of Accountancy). In addition, these expenses include dues and memberships paid to organizations that:

- provide educational opportunities for NW Natural employees (e.g., American Institute of Certified Public Accountants, American Society of Safety Professionals and the Association of Threat Assessment Professionals),
- certify NW Natural employees for specialized job functions (e.g., the Information Systems Audit and Control Association (ISACA), and the Oregon State Bar Association), and
- provide opportunities to build and maintain relationships with other entities operating in the natural gas industry (e.g., the American Gas Association ("AGA"), Western Energy Institute, and the Coalition for Renewable Natural Gas).

Q. How did Staff review and analyze the Company's dues and memberships expenses?

A. Staff witness Mr. Rossow reviews a list of memberships from NW Natural's response to Data Request Nos. 90 and 130. He then classifies memberships into

two groups: (1) for memberships related to national and regional industry trade organizations; and (2) membership he attributes to economic development and civic organization.[63]

Q. Based on this review, what adjustment does Staff propose to the Company's memberships and dues expenses?

A. Staff makes the following recommendations: (1) disallow 25 percent of expenses associated with national and regional industry organizations, on the basis that these organizations conduct some level of lobbying and promotional activities, or otherwise do not benefit customers; and (2) wholly disallow expenses associated with economic development and civic organizations.[64] Staff recommends reducing the Company's Test Year expenses by $481,938.[65]

Q. Please explain your general concerns with Staff's framework for evaluating dues and memberships expenses.

A. Staff's framework would inappropriately disallow costs associated with two categories of organizations: (1) Staff identified memberships to national and regional industry trade organizations (at 25 percent) and (2) Staff identified memberships for organizations related to economic development and civic organizations (at 100 percent). Both disallowances improperly assume that shareholders—rather than customers—are receiving the benefit of the Company's memberships.

[63] Staff/1700, Rossow/12.

[64] Staff/1700, Rossow/12.

[65] Staff/1700, Rossow/12-13.

With respect to Staff's characterization of memberships for organizations related to economic and civic organizations, the costs of which are primarily made up of all chambers of commerce dues, the Company's memberships enable the Company to be engaged with the local communities in which we serve. NW Natural is a corporate member of over 40 local chambers of commerce throughout our service territories. These organizations support local businesses and their operating environments, providing education and programs for members that address local challenges and opportunities, staffing and workforce development needs and member education and local leadership programs. Utilities, both investor-owned and public, have traditionally participated in chambers of commerce as our organizations are viewed as critical local infrastructure and economic partners for the communities and businesses we serve.

With respect to national and regional industry trade organizations, Staff ignores the significant and diverse benefits offered by these organizations, including training, education, and community relations. Certainly, there is no reason to conclude that membership in such organizations like the American Society of Safety Professionals is for the benefit of shareholders, but instead is an expense of doing business to safely serve utility customers. Thus, Staff's 25 percent disallowance is inappropriate.

Q. Do you agree with Staff's calculation of the proposed disallowances?

A. No. It appears Staff's workpaper combines the initial DR 130 response that lists the Company's dues and memberships expenses for Q1-Q3 of the Base Year ($586,347 Oregon allocated expense) with the supplemental response to DR 130

that includes expenses occurring in Q4 of 2023 ($351,779 Oregon allocated expense), which should have produced an Oregon allocated expense of $938,127 in the Base Year. However, in Staff's workpaper the total is $1,172,694. It appears in the consolidation of files some entries are duplicated. For instance, the PHMSA user fee only occurs once in the data responses, yet Staff's file has it in twice.

Q. Do you agree with how Staff allocates the transactions to the two categories?

A. No, for instance, using the example of the PHMSA fee from above, this expense was incorrectly classified to this GL account in April 2023 and in the same closing period was moved out of Dues/Memberships. In the transaction details Staff uses for their adjustments there is both an expense of $258 thousand and a credit for $258 thousand to move it out of Dues and Memberships. Staff includes the $258 thousand expense to calculate a $60 thousand disallowance (at 25 percent) but does not include the $258 thousand dollar credit. Therefore, this one error alone makes up $60 thousand of the proposed disallowance.

In addition, as stated above some transactions appear to be duplicated in Staff's workpaper and, in this instance, the PHMSA fee was duplicated and in both instances the credit was not included. Therefore, this total error is $118 thousand of the total $482 thousand dollar adjustment.

Q. Why does NW Natural participate in memberships with chambers of commerce and economic development organizations?

A. In almost all chamber and economic development organizations that NW Natural supports, critical infrastructure providers like utilities, municipalities and

jurisdictions participate because these organizations provide a direct connection to the businesses in our service areas. This connection provides a vehicle for keeping abreast of area business issues and conditions, as well as sharing information that may be important for businesses to learn about or know. Additionally, ratepayers benefit from these memberships through healthy business environments and the employment and business development opportunities they provide.

Q. What do the chambers of commerce membership fees that utilities, municipalities, jurisdictions, and other businesses pay for?

A. Membership fees provide organizations funding to cover general organization operations including staff expense, office space, and membership recruitment. Membership fees are the only portion of NW Natural's chamber of commerce and economic development participation that is paid through O&M cost centers.

Q. If a chamber of commerce or economic development organization engages in lobbying, do ratepayers pay for that through the membership fee?

A. No. When an organization shares the percentage of membership fee that goes toward lobbying, NW Natural attributes that portion to a non-utility lobbying cost center.

Q. What other expenses does NW Natural pay to chambers of commerce and economic development organizations that are paid by shareholders?

A. When NW Natural supports organization events and programs through event sponsorships, registration expenses and incidental expenses like mileage, parking

and meals and entertainment are paid for and attributed to non-utility civic cost centers.

Q. Does any other party propose adjustments to Dues and Memberships expenses?

A. Yes, Coalition witnesses Apter and Connolly propose adjustments to memberships and dues. The Coalition is concerned that NW Natural would include any payments to outside groups and trade organizations that "commonly engage in political activities and expend considerable effort to market and promote gas utilities. Consequently, their membership dues are not expenditures that benefit customers, and they are not necessarily for furnishing utility service."[66]

The Coalition specifically discusses membership and dues for AGA, Northwest Gas Association ("NWGA"), Chambers of Commerce and other "utility adjacent" organizations as regularly engaging in lobbying or political activities and expend considerable efforts to market and promote gas utilities.[67]

Q. How does the Coalition describe "Utility Adjacent" organizations?

A. The Coalition describes these organizations as groups that have focused purposes that are unrelated to the provision of service to Oregon gas utility customers and instead promote continued or increased gas usage.[68]

[66] Coalition/200, Apter-Connolly/74.

[67] Coalition/200, Apter-Connolly/71, 74.

[68] Coalition/200, Apter-Connolly/80.

Q. Based on this review, what adjustment does the Coalition propose to the Company's memberships and dues expenses?

A. The Coalition proposes removing all expenses made to any of the above-described organizations that engage in substantial political activity or in community service and economic development, and proposes a disallowance of $801,277.[69]

Q. Does the Company agree that the Staff and Coalition disallowances are appropriate?

A. No. These organizations provide a benefit to NW Natural's customers and are a reasonable business expense that should be recoverable. These organizations keep employees informed and trained, provide opportunities to build and maintain relationships with other entities operating in the natural gas industry, and, in many cases, directly take on issues that benefit customers (e.g., the AGA engaging in federal tax reform and increased LIHEAP funding). They directly benefit employees' work performance, and in some cases are simply *necessary* for the Company's employees to perform their jobs and for the Company to operate.

Q. Please provide some examples of memberships that are essential for the Company's operation.

A. The Company pays dues to the Oregon Bar Association on behalf of its lawyers and to the Board of Accountancy on behalf of its accountants. These dues are required for these employees to practice their professions. Another expense in this category is our subscription to the WebICE service. WebICE is an energy

[69] Coalition/200, Apter-Connolly/82.

trading system that allows its members to see real-time natural gas pricing information at the various hubs where the Company purchases gas. This system allows the Company to track real-time pricing and ensure that its deals align with the market.

Q. Please describe the role of the AGA.

A. The AGA's mission is to represent companies delivering natural gas, and to promote the safe, reliable, and efficient delivery of natural gas to homes and businesses across the nation. The AGA's activities include initiatives to improve the safety, efficiency and productivity of member companies' engineering and operating functions, such as:

- Technical Committees and Taskforces, addressing topics such as construction operations, cybersecurity strategy, enterprise risk management, gas control, and natural gas security.
- Technical Discussion Groups covering issues such as asset management, corrosion control, emergency management and public safety, emissions reduction and field worker assault prevention.
- Mutual Assistance Program and Emergency Planning Resource Center, which facilitates response, recovery, and restoration of services following a natural or other disaster.
- Technical Publications, regarding specific equipment, pipelines, gas measurement, leaks, etc.

Q. Please describe the role of the NWGA.

A. The NWGA's mission is to advance the safe, dependable, and responsible use of natural gas, to foster greater understanding and informed decision-making among industry participants, opinion leaders, and governing officials in the Pacific Northwest on issues related to natural gas. The NWGA's activities include:

- Convening industry CEOs to share information about the industry.
- Providing information through publications, speeches, seminars, and conferences on important topics such as safety, alternative fuels for vehicle fleets and new alternative fuel technologies.
- Providing educational blogs and newsletters on industry developments.
- Developing collective industry perspectives on key regulatory issues, such as winter storms and regional planning.

Q. Does the AGA or NWGA engage in lobbying and other political activities?

A. Yes, both organizations engage in lobbying and political advocacy. However, as can be seen from the above, political work is just one area of activity among many others. For this reason, expenses related to dues and memberships are not booked to the FERC accounts reserved for lobbying and political activities.

J. Board of Directors' Fees and Related Expenses

Q. Does any party propose adjustment to the Company's Board of Directors' fees and related expenses?

A. Yes. AWEC witness Mullins proposes an adjustment that would disallow 90 percent of the Company's Board of Directors' fees on the premise that "directors

primarily benefit shareholders, and that NW Natural is now structured as a holding company."[70] AWEC claims "given that NW Natural is now structured as a holding company, with a major focus on acquiring new businesses in new markets, the focus of the directors is now less on its gas business and more on NW Natural as a holding company."[71]

Q. Does Staff propose an adjustment to the Company's Board of Directors' fees or related expenses?

A. No.

Q. Does the Company agree with AWEC's proposed adjustment?

A. No, for a couple of reasons. First, AWEC offers no evidence beyond speculation that the Board of Directors is more concerned with furthering the interests of shareholders than benefiting customers, or that the Board of Directors' fees and expenses are not reasonable. Indeed, AWEC's assertion is simply untrue. The NW Natural Board of Directors' interest is in ensuring a strong, stable, and efficient natural gas utility that serves its customers in a safe, reliable, and affordable manner. NW Natural's Board of Directors has a proven track record of effectively balancing the Company's central interests, and the NW Natural Board's continued oversight, governance, and guidance is, beneficial, necessary by law, and required by the OPUC pursuant to ring-fencing provisions imposed when the Commission approved the company's holding company structure.

[70] AWEC/100, Mullins/38.

[71] AWEC/100, Mullins/38.

Second, AWEC's proposed adjustment appears to misunderstand NW Natural's structure. In accordance with the Commission ring-fencing provisions in docket UM 1804, NW Natural maintains a separate Board of Directors, which includes an independent director. AWEC appears to contend that NW Natural's Board of Directors' time is being spent on affiliate or non-utility matters. On the contrary, because of the holding company reorganization, all non-utility entities have been moved out from under NW Natural, and therefore, the NW Natural Board does not spend any time on matters relating the Northwest Natural Holdings LLC's ("NW Holdings'") water business or other subsidiaries. To be clear, in this rate case, NW Natural seeks to recover only NW Natural's Board of Directors fees—not those for NW Holdings. The fees for NW Holdings' Board of Directors, which is where water and other acquisitions are governed, are fully absorbed by shareholders and are not charged to NW Natural. It is also worth mentioning, that as of December 31, 2023, NW Natural is the overwhelming driver of the NW Holdings' consolidated enterprise, comprised over 92 percent of the consolidated assets of NW Holdings.

K. Water Insurance

Q. Please explain AWEC's proposed disallowance for water insurance costs.

A. AWEC witness Mullins proposes to remove $775,938 of revenue requirement related to water company insurance costs that he sees in his review of transactional data provided in Staff Data Request 201 that he states "are

associated with the water company operations but recorded on NW Natural's books."[72]

Q. Do you agree with AWEC that these expenses are associated with water company operations but recorded on NW Natural's books?

A. I do agree that the individual transactions Mr. Mullins sees are occurring on NW Natural's books, but the accounting treatment for these costs removes this expense and reallocates them to the correct entities.

Q. Can you explain the accounting for insurance expenses?

A. Consistent with NW Natural's Cost Allocation Manual the Company's annual insurance renewal is allocated to the affiliates benefitting from the insurance renewal after it is paid by NW Natural. As part of this annual insurance renewal process there are also some insurance policies that may be procured for affiliates only; these are referred to as the affiliate stand-alone policies. These stand-alone policies that benefit others are allocated 100 percent to the affiliates they benefit along with the shared services and administrative overhead from the NW Natural team involved in procuring the insurance.

Q. Do you believe an adjustment is needed to remove any insurance expense related to water or any other entity out of the utility in this case?

A. No. While the accounting for these prepaid insurance expenses and allocations can be challenging to understand based on individual transactions, insurance costs included in this case represent only the gas utility's allocations and no

[72] AWEC/100, Mullins/40.

adjustment is warranted. In prior cases there have been data requests about the Company's allocation of insurance renewals to demonstrate these allocations of insurance costs. The 2023 insurance renewal included $849,741 of water stand-alone insurance policies (system), which represents the same policies Oregon allocated of $775,938 identified by AWEC that were allocated 100 percent to water. The total stand-alone water policies were allocated out of NW Natural's expense accounts in October 2023 as part of excel line 79755 in UG 490 OPUC DR 201 Attachment 3 (NW Natural/3505, Davilla), as described in the Company's Supplemental Response to UG 490 OPUC DR 201 (NW Natural/3506, Davilla). The remaining insurance applicable to NW Natural is summarized in Amended Confidential UG 490 DR 224 Attachment 1 (Confidential NW Natural/3507, Davilla), described in the Company's Supplemental Response to UG 490 OPUC DR 224 (NW Natural/3508, Davilla).

L. Water Company Expenses

Q. Please explain AWEC's proposed disallowance for water company expenses.

A. AWEC witness Mr. Mullins proposes to remove $50,000 of expenses or $51,672 of revenue requirement related to water company expenses.[73] The Company in AWEC Data Request Nos. 23 and 24 acknowledges that there were some operating expenses included that were improperly recorded to the gas utility. AWEC states that the Company "identified $33,714 of Oregon allocated expenses

[73] AWEC/100, Mullins/41.

that were improperly recorded."[74] In addition to the above transactions, Mr. Mullins states that "transactional data are generally vague", and that there "were also items clearly related to the water business that were missed in NW Natural's review."[75] He goes on to provide an example of a $247 charge with the description of "Meetings w/AZ Commissioners."[76] Mr. Mullins concludes that since "there are some expenses remaining in NW Natural's case related to its water business and given the vague descriptions" he recommends a $50,000 expense disallowance.[77]

Q. Do you agree with the adjustment amount that Mr. Mullins proposes?

A. No. In the Company's responses to UG 490 AWEC DR 23 and 24 (NW Natural/3509, Davilla and NW Natural/3510, Davilla) the Company does acknowledge inadvertent remaining charges that occurred of $33,714 in calendar year 2023, however the Company in the response specifically separated out $27,789 of expenses that occurred during the period of January through September 2023. The Base Year in this case is made up of nine months actuals, January through September 2023, and the Company's projected spend for the last three months of the year. That projection did not include any expected water expenses occurring in the utility. Therefore, the Company would agree that the Test Year inadvertently included the $27,789 but rejects the additional disallowance of $5,925 not included in this case.

[74] AWEC/100, Mullins/40.

[75] AWEC/100, Mullins/41.

[76] AWEC/100, Mullins/41.

[77] AWEC/100, Mullins/41.

Q. Are there more water expenses that should be removed beyond the amounts included above?

A. Yes, as Mr. Mullins points out there are additional transactions that were missed during the Company's initial review that should also be removed from this case. Additional review has found $1,854 of travel related expenses to water service territory. These expenses should be excluded.

Q. Do you believe any further adjustment should be applied for vague descriptions or other unidentified expenses?

A. No. While the Company admits to missing some transactions related to water in its initial review, I do not believe a "blanket" adjustment assuming there are other water expenses in utility results is warranted. If any further water transactions are identified during this processing of this case, the Company would agree to remove them.

Q. What is the Company's total amount of adjustment for water expenses?

A. The Company is proposing to remove the $27,789 expense identified in AWEC DR 23 Attachment 1 (NW Natural/3509, Davilla), and an additional $1,854 of water expenses found during further review for a total expense adjustment of $29,643.

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M. Legal Fees

Q. What is the Coalition's recommendation regarding the Company's recovery of legal fees in rates?

A. The Coalition recommends that the Commission "disallow $701,290.23 in legal fees for Baker Botts and Snell & Wilmer LLP from FERC Account 921,"[78] "associated with NW Natural's litigation expenses related to its lawsuits against the CPP and the Washington Building Code amendments."[79] Although the Coalition acknowledges that the Company stated that it "is not seeking in this case to recover from Oregon ratepayers the legal fees of Baker Botts LLP or Snell & Wilmer LLP associated with NW Natural's legal challenge to the invalidated CPP,[80] the Coalition has "serious concerns" about that statement "given the absence of documentation provided by the company to substantiate its claim that they removed CPP litigation costs."[81] The Coalition also recommends that [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**].[82]

[78] Coalition/200, Apter-Connolly/8, 34.

[79] Coalition/200, Apter-Connolly/17.

[80] Coalition/200, Apter-Connolly/22; Coalition/238, Apter-Connolly/1.

[81] Coalition/200, Apter-Connolly/22.

[82] Coalition/200, Apter-Connolly/17-18.

Q. Just to be clear, does the Company seek in this case to recover from Oregon ratepayers the legal fees of Baker Botts or Snell & Wilmer associated with NW Natural's legal challenge to the invalidated CPP?

A. No. The Company does not seek to recover from Oregon ratepayers the legal fees of Baker Botts or Snell & Wilmer associated with NW Natural's legal challenge to the invalidated CPP.[83]

Q. Did the Company provide documentation in this case to support this fact?

A. Yes. The Company provided documentation to support this fact in my Test Year O&M Model, which the Company provided to the parties in this case as my workpaper, UG 490 – Exh. 1400 – OM Model Workpaper-Non-Confidential, an electronic copy of which I am providing as an exhibit to my Reply Testimony, NW Natural/3512, Davilla. In the tab "Dept Non-Payroll Forecast," specifically excel row 3386, for Cost Center 10835 (Legal Fees-Risk-Offi), GL Account 605000 (Legal Fees), I subtracted a total of $255,891 in columns Z through AH, which equals the total amount of actual legal fees that the Company paid to Baker Botts and Snell & Wilmer in January through September 2023 of the Base Year associated with NW Natural's legal challenge to the invalidated CPP. The Oregon allocated amount removed is $225,512. Recall that the Company forecasted the expenses for the remaining three months of 2023 to develop the Base Year O&M expenses,[84] so any actual legal fees that the Company paid to Baker Botts and

[83] NW Natural/3511, Davilla/1, NW Natural Response to UG 490 Coalition DR 219.

[84] NW Natural/1400, Davilla/2.

Snell & Wilmer in those three months associated with NW Natural's legal challenge to the invalidated CPP were not included in the Base Year O&M expenses.

Q. Furthermore, is the $701,290.23 in legal fees for Baker Botts and Snell & Wilmer that the Coalition recommends be disallowed limited to those firms' work "associated with NW Natural's litigation expenses related to its lawsuits against the CPP and the Washington Building Code amendments"[85] as the Coalition alleges?

A. No. NW Natural/3513, Davilla, is a copy of Coalition/226, Apter-Connolly, with yellow highlighted rows reflecting actual legal fees, which the Company removed from this case as I just described, that the Company paid to Baker Botts and Snell & Wilmer in January through September 2023 of the Base Year associated with NW Natural's legal challenge to the invalidated CPP. As NW Natural/3513, Davilla shows, Baker Botts and Snell & Wilmer represented the Company during the Base Year on matters not associated with NW Natural's litigation expenses related to its legal challenge to the invalidated CPP and the Washington Building Code amendments.

Q. Has the Company described the broader extent of legal representation received from Baker Botts and Snell & Wilmer during the Base Year?

A. Yes. The Company described the broader extent of legal representation received from Baker Botts and Snell & Wilmer during the Base Year in Confidential NW Natural/3514, Davilla, which is the Company's response to UG 490 Coalition DR

[85] Coalition/200, Apter-Connolly/17.

220 (including confidential material). Baker Botts [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] but even its representation of the Company on those identified matter types is not restricted to "lawsuits against the CPP and the Washington Building Code amendments." Snell & Wilmer [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**]. Thus, Snell & Wilmer's representation

[86] Confidential NW Natural/3514, Davilla/2.

[87] Confidential NW Natural/3514, Davilla/2.

[88] Confidential NW Natural/3514, Davilla/2-3.

[89] Confidential NW Natural/3514, Davilla/2.

[90] Confidential NW Natural/3514, Davilla/2.

[91] Confidential NW Natural/3514, Davilla/2.

of the Company is not restricted to "lawsuits against the CPP and the Washington Building Code amendments."

Q. How do you respond to the Coalition's assertion that NW Natural "may have charged Oregon ratepayers for litigation against the Washington Building Code Amendments"?[92]

A. During the preparation of its Reply Testimony, the Company discovered that it had inadvertently included in this case to recover from Oregon ratepayers legal fees of $48,539 related to the CCA and Washington SBCC's amendments to the building codes.[93] The blue highlighted rows in NW Natural/3513, Davilla, reflect the entries of legal fees related to the Climate Commitment Act and Washington State Building Code Council's amendments to the building codes that comprise the $48,539. As a result, the Company has removed $48,539 from the revenue requirement presented in its Reply Testimony of Kyle T. Walker, NW Natural/3800, Walker.

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[92] Coalition/200, Apter-Connolly/27-31.

[93] NW Natural/3515, Davilla/1, NW Natural's Amended Response to UG 490 Coalition DR 218.

Q. Recognizing that the Company removed and does not seek in the case to recover from Oregon ratepayers the legal fees of Baker Botts or Snell & Wilmer associated with NW Natural's legal challenge to the invalidated CPP, and that the Company has removed $48,539 from the revenue requirement presented in its Reply Testimony associated with the CCA and SBCC's amendments to the Washington State's building codes, should the Company be allowed to recover from Oregon ratepayers the legal fees of Baker Botts and Snell & Wilmer that remain in this case?

A. Yes. The legal fees of Baker Botts and Snell & Wilmer that were not removed and remain in this case are recoverable from Oregon ratepayers and benefit our customers because they are legitimate, reasonable costs incurred to ensure that NW Natural complies with laws and regulations in the operation of the business and protects our customers and their assets in the provision of utility service.

Q. Do you agree with the Coalition's recommendation that [BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]?**[94]

A. No. As the Company explained in NW Natural/3514, Davilla, **[BEGIN CONFIDENTIAL]** [redacted]

[94] Coalition/200, Apter-Connolly/17-18.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[**END CONFIDENTIAL**].

Q. Does this conclude your Reply Testimony?

A. Yes, it does.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibits of Tobin F. Davilla

OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES EXHIBITS 3501 – 3515

June 4, 2024

EXHIBITS 3501-3515– OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES EXHIBIT 3501

This confidential exhibit is being filed in its native, Excel form.
No redacted version exists.

June 4, 2024

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES EXHIBIT 3502

June 4, 2024

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 404

Referencing NW Natural/1400, Davilla/pg. 11, Contracted Customer Payment Processing Fees (FERC 903), and NW Natural/1405, Davilla/pgs 1-14:

a. When does the current contract expire?

b. What is the Oregon-allocated total actual expense for this contract for the years 2020-2023?

c. What is the Oregon-allocated total forecast expense for this contract for 2024?

d. What is the Oregon-allocated Test Year forecast for this expense?

e. Please explain and demonstrate the basis for the Oregon-allocated forecast increase to this contract in the Test Year.

f. When (month/year) does the Company expect to have an amended contract in place?

g. What efforts has the Company made to ensure that costs for bankcard services are competitive? Please describe and demonstrate.

Response:

A. The testimony states that the Company "expects to sign a contract amendment and extension in the near term." NW Natural/1400, Davilla/Page 11, Lines 11-12. An extended contract was entered into on December 27, 2023, and is provided as Confidential UG 490 OPUC DR 404 Attachment 1. The current contract expires May 4, 2027.

B. The Oregon-allocated total actual expense for this contract for the years 2020-2023 are as follows:

Period	System Wide	Oregon Allocation
2020 Oct to Dec	$633,000	$557,000
2021	$3,460,000	$3,045,000

2022	$3,930,000	$3,459,000
2023	$4,370,000	$3,846,000

C. The Oregon-allocated total forecast expense for this contract for 2024 is as follows:

Period	System Wide	Oregon Allocation
2024	$5,339,332	$4,699,146

D. The Oregon-allocated Test Year forecast for this expense is $5,490,211 ($6,237,881 System).

E. Please see NW Natural/1400, Davilla/Page 11, Lines 12-16. Primary factors for the Oregon-allocated forecast increase to this contract in the Test Year are:

   a. Customers have expressed a significant preference for bankcard payments.
   b. Migration of customers from 1.) paper payment methods (mailing a check) and 2.) customer specific bank bill pay methods to 3.) autopay methods via ach or bankcard or 4.) one time ach and bankcard payments.
   c. Test Year transactions are expected to grow at a 10 percent compound annual growth rate from the Base Year to the Test Year.

F. Please see the response to subpart A.

G. Before extending the current contract, competitive pricing was received from two other processors that provide bankcard processing services. The pricing of each of those other two processors was greater than our current and selected processor. Vendor A's proposal was approximately 39% more expensive and Vendor B's proposal was approximately 47% more expensive. Please see Confidential UG 490 OPUC DR 404 Attachment 2 for a comparison of those proposals and the Paymentus extended contract.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES EXHIBIT 3503

This confidential exhibit is being filed in its native, Excel form.
No redacted version exists.

June 4, 2024

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES EXHIBIT 3504

REDACTED

Per Commission's General Protective Order No. 23-132, this exhibit is confidential in its entirety and has been redacted.

June 4, 2024

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES EXHIBIT 3505

This exhibit is being filed in its native, Excel form.

June 4, 2024

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES EXHIBIT 3506

June 4, 2024

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 201

Please provide a supplement to SDR 57 and include actual transactional cost summaries for all **(Non-Labor)** costs for 2021, 2022, and 2023.

Response:

Refer to UG 490 OPUC DR 201 Attachment 1 for a supplement to SDR 57 for the non-labor transaction costs for 2021. This was previously provided in UG 435 OPUC DR 401.

Refer to UG 490 OPUC DR 201 Attachment 2 for a supplement to SDR 57 for the non-labor transaction costs for 2022. Note that we had a system change and related significant account coding change in September 2022 which can be observed in the 2022 transaction results.

A supplement to SDR 57 for the remainder of 2023 will be provided after NW Holdings files its 10-K for 2023 in late February 2024. **This request is now being supplemented with the 2023 non-labor transactional costs as a supplement to SDR 57 as UG 490 OPUC DR 201 Attachment 3.**

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES EXHIBIT 3507

This confidential exhibit is being filed in its native, Excel form.
No redacted version exists.

June 4, 2024

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES EXHIBIT 3508

June 4, 2024

NW Natural®

Rates & Regulatory Affairs

UG 490

Request for a General Rate Revision

Data Request Response

Request No.: UG 490 OPUC DR 224

Related to Company Insurance (non-labor, non-medical) primarily in FERC 924, please provide the following in a format similar, but not limited, to the below for the noted years for Oregon. If there are additional insurance expenses not listed below or the total amount per year doesn't match the Company's response to SDR 58B, please add lines as necessary to explain the difference. Please notate and use a separate line for D&O Insurance.

Insurance Type	FERC Acct	Cost Element	Test Year	Base Year	Base Year -1	Base Year -2
Property Premium "All Risk Property Premium"						
Property - Uninsured Loss						
Liability Premium"Excess Liability Premium"*						
Liability - Uninsured Losses						
Terrorism Premium						
Terrorism Uninsured Losses						
Excess Workers' Comp Premium						
Excess Workers' Comp - Uninsured Losses						
Other Risk Management Expenses (FERC accounts 924 & 925)						

Response:

The requested table was intended to be originally included in UG 490 OPUC SDR 68 and has been updated for Confidential UG 490 OPUC DR 224 Attachment 1. The original table in UG 490 OPUC SDR 68 was prepared on a total premium year basis vs. the actual fiscal year system allocated and did not include some of the other FERC 924 insurance categories such as Cyber, Fiduciary, and D&O as they weren't included in the original SDR template. Refer to an update in UG 490 OPUC SDR 224 – Attachment 1.

In Confidential UG 490 OPUC DR 224 Attachment 1 we have reconciled to FERC 924 in UG 490 OPUC SDR 58B.

This response has been amended to break out the D&O insurance premiums further. Note that only 2020 and 2021 were impacted and had the Crime and Travel premiums included with D&O. Refer to Amended Confidential UG 490 DR 224 Attachment 1.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES EXHIBIT 3509

Part of this exhibit is being filed in its native, Excel form.

June 4, 2024

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 AWEC DR 23

Reference Staff Standard Data Request 57, Attachment 1: Please identify each transactional accounting entry associated with the Truxton Cerbat Acquisition in calendar year 2023.

Response:

In reviewing this data request, the Company has identified p-card transactions related to the Truxton Cerbat acquisition that were inadvertently coded to the gas company. NW Natural is currently updating its response to SDR 57 for actuals through December 31, 2023 and will remove any such transactions in the amended SDR. Additionally, the Company will identify each such transaction so that the inadvertent error can be corrected in the revenue requirement request.

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 AWEC DR 23

Reference Staff Standard Data Request 57, Attachment 1: Please identify each transactional accounting entry associated with the Truxton Cerbat Acquisition in calendar year 2023.

Response:

In reviewing this data request, the Company has identified p-card transactions related to the Truxton Cerbat acquisition that were inadvertently coded to the gas company. NW Natural is currently updating its response to SDR 57 for actuals through December 31, 2023 and will remove any such transactions in the amended SDR. Additionally, the Company will identify each such transaction so that the inadvertent error can be corrected in the revenue requirement request.

Supplemental Update:

The Company has updated its response to SDR 57 for actuals through December 31, 2023 and removed any inadvertently coded transactions. Refer to UG 490 AWEC DR 23 Attachment 1 for a summary of the transactions removed. Refer to UG 490 OPUC DR 201 Attachment 3 for the updated SDR 57 response.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES EXHIBIT 3510

June 4, 2024

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 AWEC DR 24

Please identify each business trip to Arizona in the base period, the purpose of the trip, the employees who made the trip, and identify each employee who made such trip.

Response:

In reviewing this data request, the Company has identified p-card transactions related to the water company related work in Arizona that were inadvertently coded to the gas company. NW Natural is currently updating its response to SDR 57 for actuals through December 31, 2023 and will remove any such transactions in the amended SDR. Additionally, the Company will identify each such transaction so that the inadvertent error can be corrected in the revenue requirement request.

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 AWEC DR 24

Please identify each business trip to Arizona in the base period, the purpose of the trip, the employees who made the trip, and identify each employee who made such trip.

Response:

In reviewing this data request, the Company has identified p-card transactions related to the water company related work in Arizona that were inadvertently coded to the gas company. NW Natural is currently updating its response to SDR 57 for actuals through December 31, 2023 and will remove any such transactions in the amended SDR. Additionally, the Company will identify each such transaction so that the inadvertent error can be corrected in the revenue requirement request.

Supplemental Update:

The Company has updated its response to SDR 57 for actuals through December 31, 2023 and removed any inadvertently coded transactions. Refer to UG 490 AWEC DR 23 Attachment 1 for a summary of the transactions removed. Refer to UG 490 OPUC DR 201 Attachment 3 for the updated SDR 57 response.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES EXHIBIT 3511

June 4, 2024

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 Coalition DR 219

Please state whether NW Natural seeks to recover from Oregon ratepayers the legal fees of Baker Botts LLP, Snell & Wilmer LLP, and Stoel Rives LLP associated with NW Natural's legal challenge to the Climate Protection Program. If NW Natural seeks recovery for these costs, please state the total amount invoiced and charged to Oregon ratepayers.

Response:

NW Natural objects under OAR 860-001-0500, in that the information requested is not relevant to this proceeding or not reasonably calculated to lead to admissible evidence and is not commensurate with the needs of this case, the resources available to the parties or the importance of the issues to which the discovery relates.

Without waiving its objections, the Company states as follows:

NW Natural is not seeking in this case to recover from Oregon ratepayers the legal fees of Baker Botts LLP or Snell & Wilmer LLP associated with NW Natural's legal challenge to the invalidated Climate Protection Plan ("CPP"). Stoel Rives LLP did not provide legal services to NW Natural associated with NW Natural's legal challenge to the invalidated CPP.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES EXHIBIT 3512

This exhibit is being filed in its native, Excel form.

June 4, 2024

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES EXHIBIT 3513

This exhibit is being filed in its native, Excel form.

June 4, 2024

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES EXHIBIT 3514

REDACTED

June 4, 2024

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 Coalition DR 220

Please describe what services the following law firms provided to NW Natural during the Base Year and/or Test Year, and the justification for recovering from ratepayers the legal fees for these firms:

a. Stoel Rives LLP
b. Klarquist Sparkman LLP
c. Davis Wright Tremaine LLP
d. Snell & Wilmer LLP
e. Paul Hastings LLP
f. Baker Botts LLP
g. Harrang Long PC
h. Perkins Coie LLP
i. Climate Edge Law Group
j. Baker & Hostetler LLP
k. Covington & Burling LLP
l. Miller Nash Graham & Dunn LLP
m. Goodwin Proctor LLP
n. Day Carter & Murphy LLP
o. Gradco LLC
p. Greenberg Traurig LLC

Response:

The Company objects to providing descriptions of the legal services provided by the listed firms in the Base Year (i.e., 2023),[1] as such descriptions are attorney-client privileged information and attorney work product and thus not discoverable. See OAR 860-001-0500(3). Without waiving its objections, the Company states as follows **[BEGIN CONFIDENTIAL]**:

[1] As the Test Year is November 1, 2024 through October 21, 2025, no legal services have been provided by the listed law firms to NW Natural during the Test Year.

[redacted]

[redacted]

[redacted]

[END CONFIDENTIAL]

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES EXHIBIT 3515

June 4, 2024

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 Coalition DR 218

Please state how NW Natural is paying for legal fees related to the following matters:

a. NW Natural's participation in lawsuits challenging the Climate Protection Program.
b. NW Natural's participation in lawsuits challenging the Washington State Building Code Council's amendments to the state building codes.
c. NW Natural's comments and participation rulemaking related to the Washington State Building Code Council's amendments to the building codes.
d. NW Natural's comments on the Climate Commitment Act.
e. NW Natural's advocacy related to Governor Brown's Executive Order 20-04.

Response:

NW Natural objects under OAR 860-001-0500, in that the information requested is not relevant to this proceeding or not reasonably calculated to lead to admissible evidence and is not commensurate with the needs of this case, the resources available to the parties or the importance of the issues to which the discovery relates.

Without waiving its objections, the Company states as follows:

a. – e. The Company is not seeking in this case to recover from Oregon ratepayers the legal fees related to the above-listed matters.

Amended Response:

During the preparation of its Reply Testimony, the Company discovered that it had inadvertently included in this case to recover from Oregon ratepayers legal fees of $48,539 related to the Climate Commitment Act and Washington State Building Code Council's amendments to the building codes. The Company will remove such costs in its Reply Testimony.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Reply Testimony of Zachary D. Kravitz and Kyle N. Griffiths

DECARBONIZATION EMPLOYEES AND RENEWABLE NATURAL GAS AUTOMATIC ADJUSTMENT CLAUSE EXHIBIT 3600

June 4, 2024

EXHIBIT 3600 – REPLY TESTIMONY – DECARBONIZATION EMPLOYEES AND RENEWABLE NATURAL GAS AUTOMATIC ADJUSTMENT CLAUSE

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I. INTRODUCTION AND SUMMARY

Q. Are you the same Zachary D. Kravitz and Kyle N. Griffiths who filed Direct Testimony in this proceeding on behalf of Northwest Natural Gas Company dba NW Natural ("NW Natural" or the "Company")?

A. Yes. Zachary D. Kravitz and Anna K. Chittum presented NW Natural/1500, Kravitz-Chittum. In NW Natural/2100, Griffiths, Kyle N. Griffiths explained that he was adopting NW Natural/1500, Kravitz-Chittum as his own testimony in place of Ms. Chittum who is no longer employed by NW Natural. Mr. Kravitz remains the co-sponsor of NW Natural/1500, Kravitz-Chittum.

Q. What is the purpose of your Reply Testimony in this proceeding?

A. The purpose of this testimony is to:

- Respond to the testimony of Staff witness Curtis Dlouhy, Staff/900, Dlouhy, regarding his proposal to disallow the recovery of four out of five decarbonization full-time equivalents ("FTEs") sought by the Company;
- Respond to the testimony of Staff witness Curtis Dlouhy, Staff/900, Dlouhy, and the testimony of the Oregon Citizens' Utility Board ("CUB") witness Bob Jenks, CUB/100, Jenks, concerning the Company's proposed changes to Schedule 198, which is the Company's Renewable Natural Gas ("RNG") automatic adjustment clause ("AAC"); and
- Respond to the testimony of Staff witness Curtis Dlouhy, Staff/900, Dlouhy, concerning the structure of future RNG investments that the Company may make.

II. DECARBONIZATION EMPLOYEES

Q. Please summarize NW Natural's Direct Testimony that requested rate recovery for five FTEs focused on decarbonization.

A. NW Natural stated in Direct Testimony that it planned to hire five additional FTEs focused on decarbonization and (subsequently-invalidated) Climate Protection Program ("CPP") compliance.[1] Specifically, NW Natural stated it planned to fill the following positions by the rate effective date in this proceeding (November 1, 2024):

1. Peak Load Management Analyst;
2. Decarbonization Compliance Rates Analyst;
3. Decarbonization Services Analyst;
4. Decarbonization Services Operations Support; and
5. Decarbonization Portfolio Manager.

The Peak Load Management Analyst will be part of the Strategic Planning Department. The Decarbonization Compliance Rates Analyst will be part of the Rates & Regulatory Affairs Department. The remaining positions will be part of NW Natural's Renewables Department.

Although NW Natural's rationale for these five positions was premised, in part, on CPP compliance, the CPP was invalidated shortly after NW Natural had written its Direct Testimony.

[1] NW Natural/1500, Chittum-Kravitz/20.

Q. Did the invalidation of the CPP change NW Natural's plans with respect to these five additional FTEs?

A. No. In Supplemental Testimony, NW Natural stated that "these five positions are still necessary for NW Natural to meet Oregon's increasing renewable natural gas ("RNG") targets under SB 98,[2] prepare for potential climate policies, and move forward with analysis for non-pipeline solutions."[3]

Q. Please summarize Staff's framework for evaluating NW Natural's request for cost recovery associated with these five FTEs.

A. Staff's Opening Testimony states that "it recognizes the need for a fine balance between allowing the Company to meet Oregon's decarbonization goals, advocating for policies in furtherance of said goals . . ." with the recognition that future Oregon greenhouse gas ("GHG") regulations are subject to judicial review and may be invalidated, like the CPP was.[4] Staff appears to be focused on whether these additional positions will be "no regrets"[5] solutions towards decarbonization given the uncertainty concerning GHG regulation in Oregon.[6]

[2] ORS 757.390-398. Per ORS 757.396, the RNG acquisition target will double from 5 percent of sales load to 10 percent in 2025.

[3] NW Natural/2000, Kravitz-Therrien/6.

[4] Staff/900, Dlouhy/6.

[5] *Id.* at 8.

[6] *Id.* at 6, 8.

Q. What is the current status of the Oregon Department of Environmental Quality's ("ODEQ") rulemaking to establish new GHG regulations?

A. NW Natural understands that ODEQ seeks to adopt new GHG regulations to replace the invalidated CPP on an accelerated schedule. ODEQ currently plans to submit these new rules for Oregon Environmental Quality Council ("OEQC") approval in November 2024 and have the new rules go into effect on January 1, 2025,[7] which is several months faster than NW Natural anticipated when it drafted its Supplemental Testimony.[8] ODEQ has already held two of the three Rules Advisory Committee ("RAC") meetings and plans to hold the final RAC meeting on June 25, 2024. According to ODEQ, the RAC "represent[s] affected parties and stakeholders" that "will review proposed rules and provide feedback on potential fiscal, economic, and racial equity impacts."[9]

Q. Is NW Natural part of the RAC?

A. Yes. NW Natural is part of the RAC and has been actively engaging in the rulemaking process. NW Natural's participation is consistent with its Supplemental Testimony, where we stated: "[W]e look forward to reengaging with [ODEQ], our customers and the communities we serve to develop cost effective, constructive solutions that address our shared climate goals."[10]

[7] https://www.oregon.gov/deq/rulemaking/Pages/CPP2024.aspx.

[8] NW Natural/2000, Kravitz-Therrien/4.

[9] https://www.oregon.gov/deq/rulemaking/Pages/CPP2024.aspx.

[10] NW Natural/2000, Kravitz-Therrien/4.

Q. Please summarize Staff's concerns with NW Natural's proposal to recover any costs associated with compliance of any future Oregon GHG regulations.

A. Staff states that it is "premature" for NW Natural to receive rate recovery for costs to implement any future Oregon GHG regulations because NW Natural will likely challenge that program in court.[11]

Q. Please respond to Staff's concerns.

A. First, regarding NW Natural potentially challenging any new Oregon GHG regulations in court, NW Natural reiterates that RAC meetings are ongoing and ODEQ has not issued any draft rules. Therefore, no party is in a position to determine what NW Natural may or may not do if such regulations are subsequently enacted. Staff's statement is unsupported and completely speculative.

Second, NW Natural is not and has never been opposed to climate regulation. In the past, it has supported legislation that would have established a cap-and-trade program in Oregon that is similar to those programs in California and Washington. Currently, NW Natural does not support the effort to repeal the Climate Commitment Act in Washington, which establishes that state's cap-and-trade program. Therefore, it is inappropriate to assume that the Company will automatically seek to challenge future Oregon GHG regulations.

[11] Staff/900, Dlouhy/5.

Third, and perhaps most importantly, NW Natural must plan to comply with future Oregon GHG regulations, regardless of potential legal challenges. In formulating its previous Integrated Resource Plan ("IRP"), the Company diligently prepared a plan to comply with the CPP, even though the CPP was being challenged in court. In addition, prior to the CPP's invalidation, the Company was planning to purchase $220 million in Community Climate Investment ("CCI") credits for CPP compliance in the first compliance period (2022-2024),[12] and had made a filing seeking recovery of a portion of such compliance costs. However, using Staff's logic, NW Natural should not have engaged in any of these planning activities, especially the IRP, because the validity of the CPP was uncertain at that time. NW Natural believes this is the wrong approach and fully intends to use these positions to assist in its compliance with future Oregon GHG regulations.

Q. Given this background, did Staff oppose NW Natural's proposal to recover the costs of all five positions related to decarbonization?

A. No. Staff recommends that NW Natural recover the costs of the Peak Load Management Analyst in rates. However, Staff does not recommend that NW Natural recover the costs of the remaining four positions.

Q. Why does Staff recommend that NW Natural recover the cost of the Peak Load Management Analyst in rates?

A. In supporting the recovery of the Peak Load Management Analyst position, Staff states that "exploring methods to reduce load holds intrinsic value for both the

[12] NW Natural/1500, Kravitz-Chittum/7.

Company and its ratepayers, irrespective of the validity of the CPP or any future decarbonization obligation the Company may have."[13]

Q. Does NW Natural agree with Staff's recommendation?

A. Yes. NW Natural supports Staff's recommendation concerning the Peak Load Management Analyst. NW Natural is in the hiring process for this position.

Q. Why does Staff not recommend that NW Natural recover the cost of the Decarbonization Compliance Rates Analyst in rates?

A. In making its recommendation, Staff states that it "does not envision there being significant analysis of the rate impacts of decarbonization absent the CPP or a successor program and would like to reiterate that the SB 98 targets are entirely voluntary."[14]

Q. Does NW Natural agree with Staff's recommendation?

A. No, it does not. First, while Staff is correct that SB 98 targets are not mandatory, that is not germane to the Decarbonization Compliance Rates Analyst. To date, the Company has cautiously invested in RNG and made several RNG purchases, but it has not approached the targets set in the law. As the Company increases RNG acquisitions in response to new GHG regulations, SB 98 (or both), it will need additional regulatory analysis that this position will conduct.

Second, Staff's argument is premised on there being no future Oregon GHG regulations. However, as shown above, ODEQ is actively working on such

[13] Staff/900, Dlouhy/8.

[14] *Id.* at 9.

regulations and it intends to have draft rules submitted to the OEQC for approval in November 2024 and for the program to go into effect on January 1, 2025. As stated above, NW Natural cannot take a wait-and-see approach to these regulations, as well as other standards currently in statute.[15] Rather, it must actively plan to comply with them, regardless of any potential litigation concerning their validity. Moreover, the Company's current plans include ongoing work to reduce GHG emissions based on both the state's current laws and its own internal policies.[16] Therefore, according to Staff's own testimony, the Decarbonization Compliance Rates Analyst will be performing "significant analysis of the rate impacts of decarbonization."

Finally, similar to the Peak Load Management Analyst, the Decarbonization Compliance Rates Analyst is a "no regrets" position that is necessary regardless of the validity of any future Oregon GHG regulations and SB 98. NW Natural expects the Decarbonization Compliance Rates Analyst to collaborate with the Peak Load Management Analyst in looking at ways to reduce load to avoid system expansions. Such work inherently has an ongoing regulatory component that involves obtaining regulatory approval of any such program, determining how to set incentives for customers to reduce load in a certain area, and how those

[15] ORS 468A.205.

[16] *See* VISION 2050, Destination Zero, available at: https://www.nwnatural.com/about-us/the-company/carbon-neutral-future#:~:text=Our%20vision%20is%20to%20champion,residents%20we%20serve%20every%20day; ORS 468A.205.

incentives are recovered in rates. Similarly, the Company is pursuing hybrid heating and geothermal heat pumps. All of these initiatives involve evaluating customer rate impacts, developing ratemaking models, and evaluating cost allocation of these initiatives with a view towards promoting fairness and equity.

Q. What is the current status of the Decarbonization Compliance Rates Analyst?

A. NW Natural has posted the position of Decarbonization Compliance Rates Analyst and is evaluating applications.

Q. Why does Staff not recommend that NW Natural recover the cost of the Decarbonization Services Analyst in rates?

A. Staff does not recommend that the Decarbonization Services Analyst be recovered in rates because it claims that the position would be involved in RNG-related projects related to meeting SB 98 acquisition targets.[17]

Q. Does NW Natural agree with Staff's recommendation?

A. No. First, regarding Staff's concerns with RNG, nothing in either Direct Testimony or Supplemental Testimony indicates that the Decarbonization Services Analyst has anything to do with RNG.[18] Rather, the Decarbonization Services Analyst will "research and analyze new and emerging technologies and develop business cases for new decarbonization services, including district energy and geothermal energy in both residential and commercial and industrial applications, as well as

[17] Staff/900, Dlouhy/10-11.

[18] NW Natural/1500, Kravitz-Chittum/21. NW Natural/2000, Kravitz-Therrien/6-7.

negotiating agreements with large customers in hard-to-decarbonize sectors for siting hydrogen and carbon capture projects."[19] Using Staff's terminology, NW Natural considers these technologies to be "no regrets" decarbonization solutions. As we stated in Supplemental Testimony, district energy and ground-source heat pumps are specific types of electrification that can reduce winter peak on both the natural gas and electric systems.[20] Decarbonizing the industrial sector is also important to help Oregon achieve its 2050 goal of a 75 percent reduction in GHG emissions relative to 1990 levels per ORS 468A.205. Having expertise in these areas gives the Company more potential decarbonization solutions.

Second, as stated above, NW Natural will plan to comply with future Oregon GHG regulations. NW Natural expects draft rules to be submitted for approval to the OEQC in November 2024, meaning that the Company can begin to make such plans shortly after the rate effective date. Therefore, the Decarbonization Services Analyst will help plan for compliance with such a program, as well as comply with existing state statutes concerning GHG emissions and our own internal decarbonization goals.[21]

[19] NW Natural/2000, Kravitz-Therrien/6-7.

[20] *Id.*

[21] *See* VISION 2050, Destination Zero, available at: https://www.nwnatural.com/about-us/the-company/carbon-neutral-future#:~:text=Our%20vision%20is%20to%20champion,residents%20we%20serve%20every%20day; ORS 468A.205.

Q. What is the current status of the Decarbonization Services Analyst?

A. NW Natural has filled this position. The new Decarbonization Services Analyst will begin work in mid-June 2024.

Q. Why does Staff not recommend that NW Natural recover the cost of the Decarbonization Services Operations Support position in rates?

A. Similar to the Decarbonization Services Analyst, Staff does not recommend that NW Natural recover the cost of the Decarbonization Services Operations Support position in rates because it claims that the position would be involved in RNG-related projects related to meeting SB 98 acquisition targets.[22]

Q. Does NW Natural agree with Staff's recommendation?

A. No. First, NW Natural understands that SB 98 RNG acquisition targets are not mandatory. However, SB 98 states that "[r]enewable natural gas provides benefits to natural gas utility customers and to the public," and, "[t[he development of renewable natural gas resources should be encouraged to support a smooth transition to a low carbon energy economy in Oregon."[23] Given that SB 98 establishes clear policy promoting the acquisition of RNG by Oregon natural gas utilities, NW Natural does not understand Staff's recommendation to deny recovery of the Decarbonization Services Operations Support position because that employee will be helping the Company acquire RNG (i.e., helping to achieve the state policy objectives articulated in SB 98).

[22] Staff/900, Dlouhy/10-11.

[23] ORS 757.390.

Second, NW Natural will need to acquire decarbonized fuels in addition to pursuing other technologies to help meet Oregon's 2050 decarbonization goal in ORS 468A.205 and to help comply with future Oregon GHG regulations. These are transformative changes that require additional FTEs. Again, NW Natural expects draft greenhouse gas rules to be submitted for approval to the OEQC in November 2024, meaning that the Company can begin to make such plans shortly after the rate effective date, and the Decarbonization Services Operations Support position will provide valuable help in complying with the program.

Third, the Decarbonization Services Operations Support position is not limited to RNG acquisitions. Rather the position will collect and manage details supporting operational contracts and finances for all of the Company's decarbonization projects, not just RNG.[24] As the Company's decarbonization portfolio grows, this position will support projects associated with other technologies, such as district energy, geothermal, carbon capture, and hydrogen, in addition to RNG projects.[25]

Finally, NW Natural is surprised to see that Staff expressed reservations with the Decarbonization Services Operations Support position because of Staff's concerns regarding adequate risk modeling and customer protections associated with the Company's Dakota City RNG project. NW Natural does not understand

[24] NW Natural/2000, Kravitz-Therrien/7.

[25] *Id.*

how that can be the case considering Staff entered into a stipulation supporting Dakota City's inclusion into customer rates.[26]

Q. What is the current status of the Decarbonization Services Operations Support position?

A. NW Natural has filled this position and the individual is working at the Company.

Q. Why does Staff not recommend that NW Natural recover the cost of the Decarbonization Portfolio Manager in rates?

A. Staff does not recommend that NW Natural recover the cost of the Decarbonization Portfolio Manager in rates because it claims that the position would only be involved in the rulemaking regarding future Oregon GHG regulations.[27] Staff does not believe that a new FTE is warranted for participation in a single rulemaking.

Q. What is the current status of the Decarbonization Portfolio Manager?

A. An existing FTE is performing the duties of the Decarbonization Portfolio Manager in addition to her existing duties. Therefore, NW Natural is no longer seeking cost recovery of the Decarbonization Portfolio Manager. The Reply Testimony of Kyle T. Walker, NW Natural/3800, Walker, removes the cost of the Decarbonization Portfolio Manager from the Company's revenue requirement.

[26] *In the Matter of Northwest Natural Gas Co., dba NW Natural, Renewable Natural Gas Adjustment Mechanism- Dakota City*, Docket No. UG 462, Order No. 23-367, at 3 (Oct. 16, 2023).

[27] Staff/900, Dlouhy/9-10.

III. RNG AAC

Q. Please describe NW Natural's two proposed changes to Schedule 198—RNG AAC.

A. NW Natural proposed two changes to Schedule 198. The first change is to permit NW Natural to defer, for later cost recovery, the costs of its RNG investments between the investment's in-service date and the rate effective date. The second change is to set the Schedule 198 earnings test at NW Natural's authorized ROE, removing the current deadband of 50 basis points below and 50 basis points above authorized ROE.[28]

Q. What were the parties' positions regarding NW Natural's proposal to defer, for later cost recovery, the costs of its RNG investments between the investment's in-service date and the rate effective date?

A. Both Staff and CUB oppose the proposal. AWEC and the Coalition do not take a position.

Q. Please summarize Staff's opposition to the deferral.

A. Staff states that NW Natural's comparison of Schedule 198 to electric utilities' Renewable Resource Automatic Adjustment Clauses ("RRAC") is not entirely fair.[29] Under the RRAC, electric utilities can defer the costs of its renewable investments between the investment's in-service date and the rate effective date, whereas such treatment is not currently available under Schedule 198. Staff

[28] NW Natural/1500, Kravitz-Chittum/14-20.

[29] Staff/900, Dlouhy/14-15.

argues that this is appropriate because electric utilities must acquire renewable electricity to comply with the state's renewable portfolio standard ("RPS"), but NW Natural is not required to acquire RNG to comply with the now invalidated CPP or any future Oregon GHG regulations.[30] Staff also states that RNG is costly and risky compared to renewable electricity and it is unclear how effective RNG will be as a compliance resource.[31]

Q. Please respond to Staff's concerns.

A. First, NW Natural disagrees that its comparison of Schedule 198 to electric utilities' RRACs is not entirely fair. Staff suggests that NW Natural could meet state greenhouse goals and comply with future Oregon GHG regulations solely "through strategic electrification, energy efficiency, non-pipes alternatives, or other means."[32] Staff, however, does not support this view with any analysis and overlooks the fact that NW Natural has a utility obligation to its customers. In other words, NW Natural must provide as much natural gas as its customers desire. Therefore, as a practical matter, NW Natural cannot both comply with future Oregon GHG regulations and fulfill its basic utility obligations solely through the non-pipeline alternatives suggested by Staff. Instead, customers continue to demand natural gas for heating, cooking, and industrial applications and NW Natural must provide it. After taking actions to mitigate this demand through energy efficiency, demand response, and other means, it naturally follows that NW

[30] *Id.* at 15-16.

[31] *Id.* at 17-18.

[32] *Id.* at 15-16.

Natural must acquire decarbonized fuels to both satisfy its customers' needs, help Oregon meet its greenhouse gas reduction goals, and comply with any future Oregon GHG regulations.

Second, NW Natural notes that Staff mentions that it "testified [in PGE's last general rate case—UE 416—that] the use of the R[R]AC should be investigated given the drastic change in policy landscape following the passage of HB 2021 to balance concerns of customer protections with resource acquisition."[33] However, to NW Natural's knowledge, such an investigation has not taken place. Therefore, NW Natural continues to believe that the disparity between RRAC and Schedule 198 continues to exist and should be remedied in this proceeding.

Finally, NW Natural disagrees with Staff's conclusion that this change "would incentivize the Company to unfairly favor RNG investments in a way that may be detrimental to customers and that allowing this deferral would sub-optimally shift both upside and downside risks onto customers."[34] Staff's argument goes to the prudency of any RNG investment, not whether a deferral is appropriate. More importantly, however, NW Natural is simply seeking the opportunity to recover costs for RNG produced between the project's in-service date and the rate effective date. RNG produced during this time benefits customers, particularly if it is used to comply with future Oregon GHG regulations and, therefore, NW Natural should have the opportunity to recover those costs.

[33] *Id.* at 16.

[34] *Id*. at 17.

Q. Please summarize CUB's opposition to the deferral.

A. CUB argues that NW Natural has failed to present adequate evidence that a deferral is necessary. It argues that NW Natural continues to seek a deferral even though it was decided in the last rate case (UG 435) and, in CUB's opinion, nothing has changed. Specifically, CUB states that NW Natural is still committed to meeting the targets in SB 98 regardless of whether they are necessary for compliance with future Oregon GHG regulations.[35]

Q. Please respond to CUB's concerns.

A. First, NW Natural would like to clarify its Direct Testimony. In testimony, NW Natural described its RNG acquisition approach prior to the Commission's order in its IRP. This prior approach was focused on meeting SB 98 acquisition targets first and then taking subsequent actions to comply with the invalidated CPP, such as the purchase of CCI credits.[36] After that order was issued, however, the Company shifted its approach towards compliance to focus on maximizing CCI credits as directed by the Commission, and then pursuing multiple, simultaneous compliance actions in the coming years to assure compliance even during cold weather, such as investing in RNG.[37] The Company was planning on taking that approach when the CPP was invalidated.

[35] CUB/100, Jenks/21-22.

[36] NW Natural/1500, Kravitz-Chittum/12-13 (citing *In the Matter of Northwest Natural Gas Co., dba NW Natural, 2022 Integrated Resource Plan*, Docket No. LC 79, Order No. 23-281, at 11-12 (Aug. 2, 2023)).

[37] *Id.*

CUB cites the Commission's order in NW Natural's previous general rate case, stating that the Commission was concerned "about the potential incentive created by the availability of an AAC to skew the company's analysis of costs and risks of alternative CPP compliance measures towards RNG projects."[38] NW Natural takes these concerns seriously and notes that in the nearly two years since that order was issued (not six months, as stated by CUB[39]), it has used Schedule 198 once for a single RNG project (Dakota City) that is equal to approximately 0.14 percent of the Company's current Oregon sales load.[40] In addition, the decision to proceed with that project was made in November 2021, nearly a year before the Commission approved Schedule 198. Therefore, Schedule 198 has not been used in the way that the Commission and CUB feared, where its use would "skew" the Company's analysis towards more RNG investments. If NW Natural receives a deferral between an RNG project's in-service date and the rate effective date, it will continue to ensure that this remains the case, while seeking to acquire adequate amounts of RNG in response to state decarbonization policies.

Finally, NW Natural notes that it is seeking a deferral to recover costs associated with meeting the state's decarbonization goals. As I stated above, NW Natural believes it is appropriate to recover the cost of the RNG produced between

[38] CUB/100, Jenks/22-23 (citing *In the Matter of Northwest Natural Gas Co., dba NW Natural, Request for a General Rate Revision,* Docket No. 435, Order No. 22-388, at 83 (Oct. 24, 2022)).

[39] *Id.* at 30.

[40] The Lexington RNG project is also recovered through Schedule 198. However, the Company sought approval of Lexington and Schedule 198 simultaneously in its last general rate case (UG 435). The Company has only sought recovery of one RNG project, Dakota City, through the Schedule 198 that was approved in Order No. 22-388.

the in-service and the rate effective date that is providing customers with a clear benefit—meeting the state's decarbonization goals[41] and complying with future Oregon GHG regulations.

Q. Absent a deferral, is there another way to address the Company's concern?

A. Yes. In Direct Testimony, we stated that Schedule 198 requires NW Natural to make a filing to include new RNG projects in rates by February 28 of each year with a rate effective date of November 1.[42] Instead of a deferral, the fixed February 28 filing date could be made flexible, which would allow the Company to time its Schedule 198 filing so that rates go into effect shortly after the project goes into service.

Q. What are the parties' response to NW Natural's alternative proposal?

A. CUB is the only party that addressed this issue, arguing that "there is no compelling reason to change what has already been agreed to," and it "would place an unnecessary burden on the Commission and Commission stakeholders."[43]

Q. Please respond to CUB's concerns.

A. First, as a threshold matter, the lack of a deferral and a fixed filing date was not "agreed to" by NW Natural in its last general rate case (UG 435). In seeking changes to Schedule 198, NW Natural is not seeking revisions to any stipulation to which it previously agreed.

[41] ORS 468A.205.

[42] NW Natural/1500, Kravitz-Chittum/17-18.

[43] CUB/100, Jenks/28.

Second, there are compelling reasons to change Schedule 198. As I have already stated, NW Natural should have the opportunity to recover costs associated with meeting the state's decarbonization goals. NW Natural has used Schedule 198 sparingly in the nearly two years since it was enacted, and it is not "skewing" its analysis to favor RNG.

Finally, NW Natural acknowledges there may be an additional burden for the Commission and stakeholders associated with the flexible Schedule 198 filing date for new RNG projects, although this issue could be mitigated through the prefiling notification process that already exists in Schedule 198. It also acknowledges that its alternative proposal could lead to multiple rate changes in a year, which the Company seeks to avoid. For these reasons, the Company continues to believe a deferral is preferrable to a flexible Schedule 198 filing date for new RNG projects. However, a flexible filing date is an improvement on the status quo where the Company has no opportunity to recover the cost of the RNG produced between the in-service and the rate effective date, even though it helps the state achieve its decarbonization goals.

Q. What are the parties' positions regarding NW Natural's proposal to set the Schedule 198 earnings test at NW Natural's authorized ROE, which would remove the current deadband of 50 basis points below and 50 basis points above authorized ROE?

A. Staff states that setting the earnings test at 50 basis points below ROE may put the Company in a regulatory bind that should be avoided.[44] Staff believes that a change to Schedule 198 "may be warranted if the Company's characterization of the issue is correct or the magnitude of the costs associated with the volume of RNG is large enough."[45]

CUB, on the other hand, opposes NW Natural's proposal, arguing that it was decided in the last general rate case.[46] AWEC and the Coalition take no position.

Q. Please respond to Staff concerning how NW Natural has characterized this earnings test issue and its magnitude.

A. We continue to believe that higher-than-forecasted RNG production increases the project's overall revenue requirement, even though per-unit costs decline. However, due to the earning test deadbands, NW Natural would not recover these additional costs. The Company agrees with Staff that such treatment puts it in a "regulatory bind."

[44] Staff/900, Dlouhy/19.

[45] *Id.* at 20.

[46] CUB/100, Jenks/29.

NW Natural, however, disagrees with Staff "that these costs are trivial in the context of the overall revenue requirement of the RNG costs and thus do not rise to a high enough level of concern to warrant a change to the existing RNG AAC [Schedule 198]."[47] Although Staff is correct that, in the isolated example of the Tyson RNG projects, the overall revenue requirement and per-unit costs both decrease as volumes increase, that is only possible because of increased physical gas sales. In other words, on off-system projects, NW Natural sells the physical gas to a third party and retains the environmental attributes. This physical gas revenue offsets the increase in variable costs. However, NW Natural would not have this physical gas revenue if the project were on-system or "bundled" (i.e., NW Natural retains both the environmental attributes and the physical gas). In that case, if volumes increased, leading to a decrease in per-unit costs, then overall revenue requirement would increase because, again, it is not being offset by the sale of the physical gas to a third party.

Q. Assuming that the costs are not "trivial," what does Staff recommend?

A. Staff recommends subdividing the earnings test into two parts. The first part would be an earnings test for fixed costs, which would retain the deadband that is currently in place. The second part would be for variable costs, which would be set at the Company's authorized ROE.

[47] Staff/900, Dlouhy/21.

Q. Does NW Natural support Staff's recommendation?

A. No. While NW Natural appreciates Staff's recommendation, we believe it introduces unnecessary complexity into the earnings test. First, NW Natural's fixed costs should remain relatively stable over time and, therefore, not drive material variances between forecasted and actual costs that are subject to the earnings test.

Second, NW Natural does not support applying two separate earnings tests to a single regulatory mechanism. This adds unnecessary complexity to the administration of the AAC and to the monthly accounting monitoring of the earnings test for review of the earnings test.

Q. How does NW Natural's proposal balance the Company's and customers' interests?

A. NW Natural's proposal follows the Commission's direction from UG 435 to apply an earnings test to the RNG AAC, which recognizes that the utility may seek cost recovery for RNG investments outside of a rate case. An earnings test can serve as a proxy to a rate case to test the utility's overall earnings when the utility is seeking cost recovery outside of rate case. NW Natural is not challenging this premise. However, there was clearly an unintended consequence of the Commission's decision that has put NW Natural in a "regulatory bind." Namely, higher costs of production do not necessarily equate to higher per unit cost of RNG. Under the current mechanism, it is possible for the following situation to play out:

- NW Natural sets annual rates for the AAC on November 1 based on its reasonable assumptions of costs and production;

- The costs in the same year are higher than expected;
- The production is higher than expected;
- The per unit cost of RNG is lower than expected;
- NW Natural's actual ROE is underearning its authorized ROE, with an actual ROE between 8.9 percent and 9.4 percent, consequently;
- NW Natural does not recover the incremental costs of production, to the extent the Company is earning at least 8.9 percent (50 basis points below its current authorized ROE).

While the Company's proposal may seem like a relatively inconsequential change to the earnings test to Staff, the Company's proposal fixes the "regulatory bind" that is embedded in the current earnings test, aligns the interests of the Company and customers to incentivize the lowest per unit cost of RNG, and adheres to the Commission's preference to utilize an earnings test for RNG projects brought forward under the RNG AAC.

Q. Please respond to CUB's concerns.

A. CUB quotes extensively from the Commission's order in the last general rate case. However, as noted by Staff, an unintentional effect of the earnings test is that it puts the Company in a "regulatory bind" when the overall revenue requirement increases and per-unit costs decline in certain circumstances. Also, NW Natural notes that its proposal helps to address some of the concerns the Commission expressed concerning the Schedule 198 earnings test. For instance, the Commission set a deadband at 50 basis points above authorized ROE, "despite

some concern that the deadband above authorized ROE could create an incentive for the company to over-forecast the costs of RNG."[48] Under the Company's proposal, there would be no deadband above authorized ROE. Instead, the earnings test would be set at authorized ROE, thereby removing the Commission's (and presumably CUB's) concern that a deadband above ROE could create an incentive to over-forecast costs.

Similarly, removing the deadband that is 50 basis points lower than authorized ROE is necessary for symmetry and, more importantly, would allow the Company to recover incremental costs for RNG projects even though per-unit costs decline. NW Natural reiterates, however, that its proposal is not one-sided. NW Natural's recovery of higher than forecasted RNG costs would be capped at its authorized ROE, which removes the Commission's concern that NW Natural may have an incentive to over-forecast costs.

IV. SHIFT IN RNG ACQUISITIONS

Q. Please summarize your Direct Testimony regarding how the Company plans to acquire RNG.

A. As mentioned above, NW Natural explained that its prior RNG acquisition strategy was focused on meeting SB 98 targets first and then taking subsequent actions to comply with the subsequently invalidated CPP, such as the purchase of CCI credits. In response to the Commission's guidance "to pursue RNG and CCIs in

[48] CUB/100, Jenks/29 (citing *In the Matter of Northwest Natural Gas Co., dba NW Natural, Request for a General Rate Revision*, Docket No. 435, Order No. 22-388, at 82-84 (Oct. 24, 2022)).

the most economical way possible,"[49] the Company signaled that it would instead seek to maximize the purchase of CCI credits and then pursue other compliance actions, such as the acquisition of RNG in Direct Testimony. If instruments similar to CCI credits are part of future Oregon GHG regulations and are an authorized compliance option, then the Company currently plans to continue to maximize these credits prior to taking other compliance actions, such as acquiring RNG, although this is dependent on the cost of such compliance instruments relative to other compliance actions.

The Company also stated that it would abandon its use of the affiliate structure that it used for its initial RNG investments consistent with Commission guidance.

Q. Did Staff respond to NW Natural's shift in approach to acquiring RNG?

A. Yes. Staff sees benefits in no longer using affiliates because it reduces administrative burden. However, Staff also believes that the affiliate could be used more productively if it were part of an offtake agreement between the affiliate and the regulated utility that insulated customers from upside and downside risk. Conversely, Staff states that it would find it acceptable if NW Natural were to house all future RNG investments under the utility's regulated arm, but cautions that this could come with greater scrutiny about the prudency of the Company's investments.

[49] *In the Matter of Northwest Natural Gas Co., dba NW Natural, 2022 Integrated Resource Plan*, Docket No. LC 79, Order No. 23-281, at 11 (Sept. 28, 2023).

Q. What is your reaction to Staff's recommendation?

A. First, NW Natural appreciates Staff's engagement on this issue and for its thoughtful analysis. Second, NW Natural has concerns with the affiliate approach suggested by Staff. Similar to NW Natural's previous use of affiliates, it may create an administrative burden because it would require the filing of an affiliated interest agreement, in addition to a separate docket for cost recovery. As Staff correctly points out, affiliated interest dockets must be resolved within 90 days, which is an accelerated timeline compared to a typical proceeding. However, this accelerated timeline could be made more workable if there was consensus that the utility could satisfy the "lower of cost or market" standard for affiliated interest agreements by demonstrating that the affiliate competed in a competitive procurement process and the utility could demonstrate that the affiliate's proposal is lower than other competitive bids (i.e. the market).[50]

Second, while the Company does not necessarily agree with the Commission's finding, the Commission stated that NW Natural's previous approach to acquiring RNG, including the use of affiliates, improperly shifted risk to customers. In Order No. 23-367, it stated: "We recognize the opportunity to own these projects through the affiliate may tend be favored by Company shareholders. In the complex structure of this deal, project performance risk passes through the Company's affiliate agreement to customers. It lands with those customers in a way that does not mirror traditional ratemaking, in which the utility would need to

[50] OAR 860-027-0048(4)(e).

manage expenses between rate cases."[51] Staff's position appears to be inconsistent with the Commission's direction. Since NW Natural is removing the risk identified by the Commission, the Company would expect Commission scrutiny of RNG projects would not increase.

Q. Does this conclude your Reply Testimony?

A. Yes, it does.

[51] *In the Matter of Northwest Natural Gas Co., dba NW Natural, Renewable Natural Gas Adjustment Mechanism- Dakota City*, Docket No. UG 462, Order No. 23-367, at 3 (Oct. 16, 2023).

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Reply Testimony of John J. Spanos

DEPRECIATION
EXHIBIT 3700

June 4, 2024

EXHIBIT 3700 – REPLY TESTIMONY– DEPRECIATION

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I. INTRODUCTION

Q. Please state your name and address.

A. John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania.

Q. By whom are you employed and in what capacity?

A. I am associated with the firm of Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming") as President. I have been associated with the firm since June 1986.

Q. Have you previously submitted Direct Testimony on behalf of Northwest Natural Gas Company dba NW Natural ("NW Natural" or the "Company") in this proceeding?

A. Yes. My Direct Testimony is set forth in NW Natural/1600, Spanos.

Q. What is the purpose of your Reply Testimony?

A. The purpose of my Reply Testimony is to address and rebut depreciation and accounting adjustments set forth by the Alliance of Western Energy Consumers ("AWEC") witness Bradley G. Mullins[1] and the Public Utility Commission of Oregon ("OPUC") Staff witness, Curtis Dlouhy.[2] OPUC Staff witness Ming Peng has not proposed any depreciation adjustments at this time.[3] Most specifically, I will address retirements and depreciation expense for computer software applications in Account 303.10, Miscellaneous Intangible Plant - Software. I will also address

[1] AWEC/100, Mullins/36-37.

[2] Staff/900, Dlouhy/57-58.

[3] Staff/1400, Peng/3-13.

the meter modernization program discussed by Staff Witness Dlouhy as it relates to depreciation.

II. PROPER TREATMENT OF ACCOUNT 303.10

Q. Please explain the proper accounting for Account 303.10, Miscellaneous Intangible Plant - Software.

A. The current practice for Account 303.10, Miscellaneous Intangible Plant – Software is to treat this account as a depreciable account just like all other group depreciation asset classes. The same depreciation recovery pattern is recommended in the depreciation study. Therefore, assets should stay on the books until they are retired or taken out of service.

Q. What is the survivor curve being recommended in the depreciation study?

A. The Depreciation Study recommends a 15-SQ type survivor curve. This means the account will have a 15-year average service life with no dispersion expected.

Q. Does a Square curve require retirement of plant at the end of the average service life as AWEC Witness Mullins suggests[4]?

A. Not necessarily. In the case of general plant amortization, there is a practice in place for accounting purposes, which recommends that assets be retired from the accounting records after the determined amortization period regardless if they are still in service. This process is discussed in Part V of the Depreciation Study as well as in my Direct Testimony. The specific general plant accounts are identified in the study. These accounts represent asset classes with many assets with

[4] AWEC/100, Mullins/36-37.

relatively low individual asset value, so it has been a common practice in the industry for over 30 years to amortize these types of assets. NW Natural has had amortization accounting in place for more than 10 years for such accounts.

Q. Does Account 303.10 fall into the general plant amortization category just because of the use of a Square Curve?

A. No. Account 303.10 does not have many small-valued assets. However, the most reasonable recovery pattern is a Square curve. Therefore, the plant in service must be recovered in the same fashion as all other group depreciable accounts that utilize the remaining life method.

Q. Does the rate for Account 303.10 properly reflect the recovery pattern for these assets over the remaining life?

A. Yes. The 16.30 depreciation rate needs to be applied to these assets in order to recover the remaining net plant over the 5-year composite remaining life. The 5-year remaining life is a composite remaining life as is the case for all depreciable accounts. There is $116 million of plant with $22 million of accumulated depreciation. As shown in the detailed depreciation calculation, the weighting of the vintages shows recovery by vintage and in order to be fully recovered over the 15-year life there is a need to recover some vintages more than what theoretically would be expected, and other vintages will have no further recovery. This is group depreciation under the remaining life technique. Looking at the vintage-by-vintage breakdown shows some vintages will be recovered for more than 5 years, which is shown on page IX-2 of the Depreciation Study. As is shown on page IX-2 there

are remaining lives for vintages 2008 through 2023 that range from 0.5 years to 14.5 years with the composite remaining life totaling 5.0 years.

III. ACCOUNT 303.10 RETIREMENTS

Q. Do you agree with AWEC's position[5] of forecasted retirements for the Account 303.10?

A. No. As stated above, this account is not an amortized account where retirements are required based on a set period of time. The square curve does not require retirements each year based on age of assets. There are no forecasted retirements and the rate for the account is based on the composite remaining life. Assets that are older than the 15-year average life do not require a retirement, however, the established rates assume that the 2009 and 2010 vintages will be fully recovered after each year of the forecast.

Q. Does the depreciation rate for the account set forth the composite remaining life rate based on the life characteristics?

A. Yes. The detail vintage balances and vintage remaining life properly reflect recovery patterns as should be recovered, thus AWEC's request of required retirements is not appropriate based on the calculation.

IV. METER MODERNIZATION PROGRAM

Q. Does Staff's criticism of the meter modernization program consider all the parameters of the life estimation for meters within the Depreciation Study?

A. No. The life estimation of all accounts within the Depreciation Study not only

[5] AWEC/100, Mullins/36-37.

considers the historical indications but future expectations. This is how proper life estimation in depreciation studies are performed.

Q. Please explain how life estimation is performed for meters.

A. There are expected to be high levels of retirements for assets that are approaching 20 years old due to failures of meters around age 20 and older going forward. The survivor curve of 30-L1 shows higher levels of retirements than what has historically occurred. Therefore, the 30-L1 curve anticipates higher levels of retirements of meters than what historically occurred. However, this does not reflect that all meters in this age group should be retired. The program only affects residential meters that are a subset of the full asset class. Consequently, when considering group depreciation and establishing survivor curves for existing assets as well as future assets, the 30-L1 curve takes into consideration the concerns that Staff witness Dlouhy has expressed in his testimony.

V. CONCLUSION

Q. Do the criticisms of Staff and AWEC concerning Account 303.10 and meter modernization program have merit?

A. No. As stated in the testimony above, each of the issues raised by Staff or AWEC have been properly addressed in the Depreciation Study. The positions of Staff and AWEC related to Account 303.10 and the recovery of the meter modernization program have been properly considered.

Q. Does this conclude your Reply Testimony?

A. Yes, it does.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Reply Testimony of Kyle T. Walker

DECOUPLING / TEST YEAR / ACCOUNTING ADJUSTMENTS/ REVENUE REQUIREMENTS EXHIBIT 3800

June 4, 2024

EXHIBIT 3800 – REPLY TESTIMONY – DECOUPLING / TEST YEAR / ACCOUNTING ADJUSTMENTS / REVENUE REQUIREMENTS

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I. INTRODUCTION AND SUMMARY

Q. Are you the same Kyle T. Walker who filed Direct Testimony in this proceeding on behalf of Northwest Natural Gas Company dba NW Natural ("NW Natural" or the "Company")?

A. Yes, I presented NW Natural/1700, Walker.

Q. What is the purpose of your Reply Testimony in this proceeding?

A. The purpose of my Reply Testimony is to respond to the adjustments proposed by:

1) Public Utility Commission of Oregon ("Commission") Staff ("Staff") witness Anderson and Alliance of Western Energy Consumers ("AWEC") witness Mullins, regarding the forward test year capital;
2) Staff witness Chipanera and AWEC witness Mullins, regarding cash working capital;
3) Staff witness Moore, regarding materials and supplies;
4) Staff witness Mondragon, regarding excess deferred income taxes ("EDIT") Amortization;
5) Staff witness Chipanera, regarding the Commission Fee;
6) Staff witness Peng, regarding Allowance for Funds Used During Construction ("AFUDC");
7) Staff witness Stevens and Coalition witness Cebulko, regarding the Decoupling mechanism;
8) AWEC witness Mullins, regarding test year revenue and expenses, removal work in progress ("RWIP") forecast, RWIP accumulated deferred income

taxes, average rate assumption method, pre-1981 flow-through items, and UM 2309 amortization; and

9) Staff witness Dyck regarding cloud-based software capitalization.

I also provide an updated revenue requirement that reflects the filed cost of long-term debt stipulation with the Stipulating Parties, errors identified through Parties' Opening Testimony and discovery, updated union labor agreement, and removal of one full-time employee.

II. FORWARD TEST YEAR CAPITAL

Q. Please summarize the Company's approach to reflecting forward test year capital in this rate case.

A. The Company's filed revenue requirement includes a 13-month average of monthly averages ("AMA") for all capital investments that runs from October 2024 through October 2025 ("the Test Year"). This method is consistent with all of NW Natural's recently filed general rate cases in Oregon over at least the last 22 years.[1] NW Natural included Test Year capital projects as follows:

1) We forecasted those costs and revenues that are reasonably certain to occur in the Test Year. NW Natural/3801, Walker details the rigorous capital expenditure budgeting process that develops our forecast of capital in the Test Year with a combination of "discrete" and "non-discrete" capital;

[1] See Docket No. UG 152, NWN/200, Miller-McVay/14-15. See Docket No. UG 221, NWN/300, McVay-Siores/13, starting at line 13. See Docket No. UG 344, NW Natural/200, McVay/24, starting at line 13, and Docket No. UG 344, NW Natural/210, McVay. See Docket No. UG 388, NW Natural/1012, Walker. See Docket No. UG 435, NW Natural/1312, Walker.

2) We pro-rated the costs of capital investments with the AMA approach to reflect their proportional benefit to customers during the Test Year; and

3) We offset forecasted costs by projected revenues for the Test Year, including new customer additions.

Q. Did the parties provide Opening Testimony addressing the forward test year capital?

A. Yes. AWEC provided Opening Testimony on the forward test year capital,[2] and Staff provided Opening and Supplemental Testimony addressing this issue.[3] My testimony responds to both parties—first Staff and then AWEC.

Q. Please explain how Staff's position regarding forward test year capital evolved over the course of this case.

A. Staff's Opening Testimony, filed on April 18, 2024, recommended that the Commission include non-discrete Test Year investments in rates and remove one discrete project that would enter service after the rate effective date.[4] On May 1, 2024, counsel for Staff communicated that its Opening Testimony contained an error as it related to Staff's position on utility plant in service included in rates during the Test Year. On May 17, 2024, Staff filed Supplemental Testimony with its new position on utility plant in service.[5] Given the limited amount of time the Company

[2] AWEC/100, Mullins.

[3] Staff/600, Anderson; Staff/2300, Anderson.

[4] Staff/600, Anderson/7-8.

[5] Staff/2300, Anderson/5.

had to respond to Staff's Supplemental Testimony, we reserve the right to expand our response regarding this issue in future testimony.

Q. What is Staff's current position provided in Supplemental Testimony regarding the utility plant in service included in rates during the Test Year?

A. Relying on ORS 757.355, Staff states that only capital investments that will be "on-line" prior to the rate effective date should be included in rates.[6] However, Staff explains that: "there is some plant that utilities can be expected to install and deploy on a consistent basis throughout a year. For such plant, it would be lawful to allow the Company to recover a portion of such plant each month. Meaning, if the Company will consistently install $10,000 of plant in each month of the year, it would be permissible for rates collected from ratepayers each month to include such an amount without violating ORS 757.355."[7]

Q. Please describe Staff's adjustment to utility plant in service in the Test Year.

A. Staff's adjustment in the test year results in a reduction of $119.4 million of rate base additions, after removing the North Coast Feeder Section B project that was erroneously included as an adjustment in Staff's Opening Testimony.[8]

[6] Staff/2300, Anderson/2-3.

[7] Staff/2300, Anderson/4.

[8] Staff/2300, Anderson/7. This project was not initially included in revenue requirement by the Company, and therefore, the removal of the project by Staff in Staff's Opening Testimony has been corrected in Staff's Supplemental Testimony.

Q. Did Staff provide a revenue requirement impact for this adjustment?

A. No, Staff did not. Additionally. Staff did not confirm that Staff would utilize "end of period" rate base, as of October 31, 2024, which has historically been Staff's practice.

Q. Was Staff's position in Supplemental Testimony consistent with the calculation of the $119.4 million adjustment in the workpapers Staff provided?

A. No. The calculation underlying Staff's adjustment of $119.4 million is inconsistent with the explanation in Staff's Supplemental Testimony that I described above. After careful review of Staff's workpaper, NW Natural determined that Staff's adjustment removes all capital additions from Federal Energy Regulatory Commission ("FERC") accounts 367 Mains, 376.11 Mains < 4", 376.12 Mains > 4", 378 Measuring and Regulating Equipment, 380 Services and a portion of 382 Meter Installations from November 1, 2024 through the entire calendar year 2025 (including two months after the Test Year). Additionally, Staff made a positive adjustment, netted against the capital addition removals, in the amount of $15 million associated with depreciation on excluded plant.

Q. Please provide an overview of the concerns you identified with Staff's adjustment calculations.

A. We identified several issues with Staff's calculations. First, the adjustment removes capital from November and December 2025 that is not included in the Company's Test Year. Second, the amount of capital additions being removed is an aggregate total and does not reflect the AMA method the Company uses to add

capital to customer rates. Lastly, it is unclear how Staff calculated the offsetting accumulated depreciation portion of its adjustment, as its workpapers included hardcoded numbers without formulae intact.

Q. Regarding the first issue, what period should Staff have been analyzing to calculate its adjustment?

A. As stated in my Direct Testimony, the Company's Test Year is November 1, 2024 through October 31, 2025. No revenue, expenses, or capital should be included beyond that period. Staff's adjustment incorrectly uses *the entire* 2025 calendar year. Because Staff removed capital entering service in November and December 2025, which was not included in NW Natural's revenue requirement, Staff's adjustment is overstated.

Q. Please explain your second concern regarding Staff's adjustment calculation.

A. As stated in Direct Testimony, the Company uses an AMA methodology for all rate base in the Test Year, but Staff's adjustment used the aggregate amount of capital additions. Within the Test Year, we proportionally add capital additions to rate base in the same month we expect the investments to benefit customers. In other words, if plant is placed in service in October 2024, the Company would recover the full amount of that project because it was in service during the entire Test Year. On the other hand, if plant is placed in service in October 2025 (the final month of the Test Year), the Company would only recover approximately 1/24th of that investment reflecting the ratio of time that the plant was in service during the Test Year using a 13-month AMA. However, Staff removed the full amount of capital

additions, rather than the proportion the Company had added into the Test Year. By ignoring the Company's use of an AMA methodology, Staff has significantly overstated its adjustment. To accurately calculate the adjustment, Staff should have removed capital additions in the same proportion that the Company added them into the Test Year. If performed properly, the amount of Staff's adjustment would have been significantly lower.

Q. Please address the third issue you identified—Staff's depreciation offset.

A. As stated above, we are unclear how Staff arrived at its depreciation offset. That said, I anticipate that Staff's depreciation offset may be flawed because it relies on Staff's incorrect adjustment calculation discussed above and potentially because it appears to use an average depreciation rate, rather than specifically calculating the depreciation expense for each FERC account. The Company will follow-up with Staff to better understand this adjustment.

Q. You noted above that Staff's adjustment is based on Staff's interpretation of the used and useful standard reflected in ORS 757.355. How is Staff interpreting the used and useful standard in this case?

A. Staff understands ORS 757.355 to require that plant be in service before the rate effective date if the plant is to be included in rates, although Staff also explains that it may be permissible to include a portion of non-discrete Test Year investment in rate base without violating the statute.[9]

[9] Staff/2300, Anderson/2-3.

Q. Does the Company agree with Staff's interpretation of ORS 757.355?

A. No. Like Staff witness Anderson,[10] I am not a lawyer, and the Company will provide its legal arguments in legal briefing. However, my understanding is that Staff's interpretation of the used and useful standard is unnecessarily narrow. I note also that Staff's position has been inconsistent over time in that Staff has had a different interpretation of the used and useful standard in each of the Company's rate cases since 2011 (UG 221).

Q. How does the Company reasonably implement the used and useful standard for capital that enters service during the Test Year?

A. The Company's 13-month AMA approach uses known forecasted additions and includes a proportion of those capital additions for rate making. The 13-month AMA is specifically designed to implement the used and useful standard by including the costs of Test Year capital projects in rate base only in proportion to the part of the Test Year that these projects provide utility service to customers. See Table 1 below for an example of how the AMA methodology considers capital additions for an investment that becomes used and useful in November 2024, April 2025, and October 2025. The AMA method produces a reasonable and fair proportion of the investment into customer rates.

[10] Staff/2300, Anderson/3.

Table 1

Investment in Service Nov 2024		Investment in Service Apr 2025		Investment in Service Oct 2025	
Oct-24		Oct-24		Oct-24	
Nov-24	$ 1,000,000	Nov-24		Nov-24	
Dec-24	$ 1,000,000	Dec-24		Dec-24	
Jan-25	$ 1,000,000	Jan-25		Jan-25	
Feb-25	$ 1,000,000	Feb-25		Feb-25	
Mar-25	$ 1,000,000	Mar-25		Mar-25	
Apr-25	$ 1,000,000	Apr-25	$ 1,000,000	Apr-25	
May-25	$ 1,000,000	May-25	$ 1,000,000	May-25	
Jun-25	$ 1,000,000	Jun-25	$ 1,000,000	Jun-25	
Jul-25	$ 1,000,000	Jul-25	$ 1,000,000	Jul-25	
Aug-25	$ 1,000,000	Aug-25	$ 1,000,000	Aug-25	
Sep-25	$ 1,000,000	Sep-25	$ 1,000,000	Sep-25	
Oct-25	$ 1,000,000	Oct-25	$ 1,000,000	Oct-25	$ 1,000,000
Rate Base Amount (AMA)	$ 958,333	Rate Base Amount (AMA)	$ 541,667	Rate Base Amount (AMA)	$ 41,667
Investment Amount	$ 1,000,000	Investment Amount	$ 1,000,000	Investment Amount	$ 1,000,000
% of Invest in Rates	95.8%	% of Invest in Rates	54.2%	% of Invest in Rates	4.2%

In all the above examples, the Company takes lag on the investment and does not recover the full amount of the investment in rates because the investment was not in service prior to the rate effective date (prior to November 2024). However, the Company does have the opportunity to recover the investment on a pro-rata share of the time it was in service during the Test Year. This methodology does not allow for the Company to over recover, nor does it eliminate the regulatory lag the Company faces for capital additions. As such, the Company would not recover the unrecovered pro-rata share of the investment until the Company's next rate case, and until that time, the Company would experience regulatory lag on the investment as it depreciates on the Company's books.

Q. Aside from the used and useful standard, is the Company's approach to forward test year capital consistent with other fundamental ratemaking principles?

A. Yes, NW Natural's approach is consistent with the matching principle, whereas Staff's adjustment is not. The matching principle is a fundamental concept in utility ratemaking that aligns all costs from a test year with all revenues from that same test year. This principle is recognized by the Commission in rate-setting dockets[11] and also is reflected, to some extent, in the Commission's ratemaking statutes.[12] The matching principle helps maintain consistency between costs and revenues, contributing to effective rate design and financial stability for utilities. NW Natural's approach aligns with the matching principle because the Company calculates all aspects of rate base based on the Test Year, rather than determining the capital additions using a different time period.

NW Natural also adheres to ratemaking principles by relying upon known and measurable changes that are reasonably certain to occur in the Test Year. Specifically, the Company completes a rigorous capital expenditure budgeting process, which develops a capital forecast that is reasonable and accurately reflects the capital additions customers will benefit from in the Test Year. In contrast, Staff's approach fails to account for reasonably certain capital additions

[11] See, e.g. *In re Avion Water Co.'s Request for a Gen. Rate Revision*, Docket No. UW 171, Order No. 17-496 at 3, 14 (Dec. 11, 2017) (recounting Staff's efforts to make sure that company's revenues from rates are comparable to the expenses incurred during the same time periods, and Commission recognition that this was a significant complication in the case).

[12] See ORS 757.259(2)(e) (describing that deferrals can be used where Commission finds that they are appropriate "to match appropriately the costs borne by and benefits received by ratepayers").

and therefore does not accurately reflect known costs that will benefit customers in the Test Year and thereafter.

Q. You indicated that Staff's recommendation does not follow the matching principle. Please explain.

A. Ratemaking principles were designed to align all costs (expense and capital) and revenues in the same period, the Test Year. This principle ensures that rates reflect the cost of providing utility services when they are incurred, thereby providing an accurate price signal to customers and promoting intergenerational equity. Staff's recommendation to remove some FERC accounts but allow many capital additions in the Test Year does not coincide with the matching principle. The Company's revenue requirement is based on a test Year ending October 31, 2025, and by excluding some capital additions, while including many others, Staff does not achieve an accurate representation of capital additions during the Test Year.

Q. Turning now to AWEC, what is AWEC's position regarding the forward test year capital?

A. AWEC believes the 13-month AMA used by the Company is not consistent with established Oregon policy. Specifically AWEC relies on ORS 757.355(1)'s used and useful standard to support its claim that capital additions must be in service by the rate effective date.[13] AWEC also argues that capital projects must be found prudent before they can be included in customer rates but that prudence cannot

[13] AWEC/100, Mullins/18.

be determined based on forecasted costs.[14] While AWEC agrees that the AMA method is the most reasonable way to measure rate base, AWEC proposes that the capital component of rate base be determined using an AMA that runs from October 2023 through October 2024.

Q. What adjustments did AWEC make regarding the forward test year capital?

A. As noted above, AWEC moves the utility plant-in-service AMA back one full year. AWEC witness Mullins also adjusts accumulated deferred income taxes related to utility plant. These changes prorate capital additions for the 12 months **prior** to the rate effective date. This proration grossly reduces the amount of rate base that is benefiting customers prior to rates going into effect and the associated depreciation expense related to that rate base. AWEC's adjustments do not accurately reflect the Test Year capital costs and essentially eliminate any chance for the Company to earn a reasonable return on rate base during the Test Year. To my knowledge, this approach has never been accepted by the Commission in a NW Natural rate case or otherwise. It is unreasonably punitive and puts the utility in a state of systemic, ongoing lag on all capital investments. As I mentioned above, using an AMA would only allow the utility to recover 1/24th of its investments placed in service in the final month of the AMA. In AWEC's proposal, this would be October 2024. As such, for all investments that are placed in service and used and useful during the entire Test Year, the Company would experience severe

[14] AWEC/100, Mullins/18-19.

regulatory lag and would only recover the full investment in a subsequent rate case. Again, this approach is extreme and cannot be accepted.

Q. Do you agree with AWEC's interpretation of the used and useful standard?

A. No, as I explained above, NW Natural does not recognize the used and useful standard to prohibit the Company's approach to forward test year capital. In reliance on this standard, AWEC defines the capital costs recoverable too narrowly. AWEC also fails to consider how the used-and-useful standard applies to the forward test year and to reconcile its interpretation of the standard with the matching principle.

Q. AWEC claims that the Commission cannot make a prudency determination based on a forecast.[15] What is your response?

A. AWEC's claim regarding forecasts is novel, unsupported, and unreasonable. The Commission has allowed forecasts into rates on many occasions, including the Company's most recent rate cases. Furthermore, the purchased gas adjustment, renewable natural gas ("RNG") automatic adjustment clause, and others are forecasted each year. As the Commission has noted, "All test years are estimates of future conditions for the utility,"[16] and prospective ratemaking appropriately relies on forecasted adjustments that are reasonably certain to occur in the Test Year.[17]

[15] AWEC/100, Mullins/18-19.

[16] *In re US West Communications, Inc., for an Increase in Revenues*, Docket No. UT 80, Order No. 00-191 at 14 (Apr.14, 2000).

[17] *See In re US West Communications, Inc., for an Increase in Revenues*, Docket No. UT 80, Order No. 00-191 at 14-15 (Apr.14, 2000).

Here, the Company's forecasts are based on a robust and reviewable process. Specifically, the details of our budgeting process can be found in NW Natural/3801, Walker. Furthermore, the Company has responded to over 905 data requests thus far in the proceeding, many related to capital additions. The process of this rate case has allowed parties to understand the capital projects and assess their prudency and timing. There is no basis for excluding Test Year capital simply because the costs are forecasts.

III. CASH WORKING CAPITAL

Q. Please summarize the Company's Direct Testimony about cash working capital.

A. Cash working capital is the amount of investor-supplied capital required to fund the day-to-day operations of the company after accounting for the timing differences between booked revenue and expenses (accrual basis) and actual cash flows (cash basis). It represents amounts funded by investors to provide service prior to payment for such service by customers and, therefore, cash working capital typically is a component of a company's rate base. NW Natural completed a lead-lag study, an analysis designed to determine the funding required to operate the Company on a day-to-day basis, to determine the cash working capital requirements for the Test Year. The results of the study show that NW Natural's average daily cash working capital requirement in Oregon for the Test Year is $22.16 million with a cash working capital factor of 2.9 percent.[18]

[18] NW Natural/1700, Walker/39.

Q. Did the parties provide Opening Testimony addressing the cash working capital?

A. Yes. Staff/800, Chipanera and AWEC/100, Mullins addressed the Company's cash working capital.

Q. What is Staff's position regarding cash working capital?

A. Staff witness Chipanera identified two areas in the lead-lag study where he believes the Company overstated its calculations. First, the Company calculated service lag by using a mid-point date, whereas Staff calculates the total number of days in a month and divides that by 2. The difference in these methodologies caused a 0.3-day decrease to the Company's service lag calculation.[19] Second, Staff identified three prepaid information technology contracts that extend into the Test Year and suggests they should be removed from the prepaid information technology expense lead days. This removal reduced prepaid information technology leads days by approximately 10.5 days.[20]

Q. How do you respond to Staff's position?

A. The first adjustment related to the service lag mid-point is reasonable, and the Company will accept this adjustment. The last section of this testimony updates the revenue requirement, which will include this adjustment.

The second adjustment related to the prepaid information technology contracts that extend beyond the Test Year is an overreach. The prepaid

[19] Staff/800, Chipanera/8-9.

[20] Staff/800, Chipanera/10-11.

information technology contracts are unique because they are prepaid. The prepayment has a large impact on the Company's cash flows because the Company pays for a service prior to the contract being fully executed. It is appropriate to include contracts that extend into the Test Year because of this uniqueness, and it reflects the downward cash flow changes for the Company. Therefore, the Company believes that it is appropriate to include contracts that extend into the Test Year because they have cash flow implications before the rate effective date. This issue is not related to the forward test year capital like the previous section and therefore should be dismissed.

Q. What is AWEC's position regarding cash working capital?

A. AWEC witness Mullins identified two areas where AWEC disagrees with the Company's lead-lag study calculations. First, AWEC argues the Company did not include "the rule which only requires estimated tax payments to cover the higher 90% of taxes payables or 100% of the taxes payable on the prior year's return"[21] to the tax lag day calculation. This adjustment results in a 22 day increase to the tax lag days. Second, AWEC believes that the Company is calculating revenue lag days only on a monthly basis, whereas AWEC calculated the lag on an annual basis. AWEC argues that, due to seasonality, the Company is overstating the revenue lag days by approximately 108 days.[22]

[21] AWEC/100, Mullins/35.

[22] AWEC/100, Mullins/33-35.

Q. How do you respond to AWEC's position?

A. The tax rule[23] AWEC identifies is only applicable to individuals, not corporations, and therefore should not be included in the Company's lead-lag study. Regarding revenue lag, AWEC's argument does not reflect the purpose of cash working capital or a lead-lag study. As stated previously, cash working capital accounts for the timing differences of cash inflows and outflows. NW Natural spends cash over a service period as customers use our services but we do not receive the actual cash until the customer pays their bill. This is the revenue lag time, 40.86 lag days, that is calculated in NW Natural's lead-lag study. The purpose of the study is to identify the timing difference between cash inflows and outflows, not to review the Company's volumetric load which is the basis of AWEC's argument. AWEC's position also violates the matching principle. AWEC witness Mullins failed to address seasonality for expenses, nor does AWEC's methodology look at the entire year as it claims. For example, the cost of gas rises significantly during the winter months, but AWEC fails to include that in its analysis. AWEC's analysis also only looks at the first four months of the gas year and does not reflect when customer usage is down, along with revenues. The Company receives less revenues from March through October when the Company continues to have steady operational expenses such as O&M and labor but receives little cash from customer bills, as usage is low. There are many components of the lead/lag study that would need to be adjusted for AWEC's methodology that were not completed

[23] See General Rule Part 2a and 2b. 2024 Form 1040-ES (irs.gov).

causing a mismatch of costs and revenues. Additionally, NW Natural used a lead/lag methodology that has been accepted by the Commission in other Oregon utilities'[24] rate cases and is consistent with best practices. Therefore, NW Natural does not agree with AWEC's methodology and rejects its proposal.

IV. MATERIALS AND SUPPLIES

Q. Please summarize the Company's Direct Testimony about materials and supplies.

A. The forecasted balances that make up the Test Year are based on a linear trend formula which uses the least squares method to calculate a forecast based on the known actuals from January 2019 to September 2023. The Company compared different forecasting methodologies used in UG 388 and UG 435 and found that the UG 388 method using the linear trend formula produced results most similar to actual September 2023 balances. A 13-month AMA of balances is used for the Test Year for a total of $21.8 million.[25]

Q. Did the parties provide Opening Testimony addressing materials and supplies?

A. Yes, Staff/1300, Moore, addressed the Company's materials and supplies.

Q. What is Staff's position regarding materials and supplies?

A. Staff witness Moore starts by doing a simple average of the months within calendar years 2021 through 2023 to get a calendar year average. Then Staff does a simple

[24] Docket No. UE 283, PGE's Lead Lag study for 2015 Test Year Supplemental; Docket No. UG 389, Avista's General Rate Case.

[25] NW Natural/1700, Walker/30; Staff/1302, Moore/3.

average of the 2021 through 2023 calendar years to get a total of $16.98 million. Staff then escalates the $16.98 million by 2.7 percent and again by 2.0 percent to get a recommended total of $17.78 million. Staff's methodology results in a downward adjustment of $4 million.[26]

Q. How do you respond to Staff's position?

A. We reject Staff's adjustment. Staff's proposed $17.8 million Test Year balance is below the Oregon-allocated actual amounts seen in December 2022, prior to the start of the Base Year, and nearly $3 million lower than the known and measurable Oregon-allocated balance as of September 2023. Therefore, Staff's proposal is plainly not representative of the Test Year.

Q. Do you have concerns with Staff's methodology for forecasting materials and supplies balances?

A: Yes. We believe Staff witness Moore's use of a three-year historical average of dollar values is an inappropriate forecasting method as it is backward looking and does not accurately account for growth or inflation seen within the 2021 through 2023 time period. According to the methodology shown in Staff/1304, Moore/Workpaper, Mat and Supplies Tab, the average of the years 2021 through 2023 values would be used as the "Base Year" ending value. Staff's method results in a "Base Year" value of approximately $16.98 million compared to the September 2023 reported actual Oregon-allocated value of approximately $20.5 million. Staff's inflation escalation factors of 2.7 percent and 2 percent are applied

[26] Staff/1300, Moore/6-7.

to the base year value to get the proposed value of $17.8 million, however these escalation factors are not inclusive of any growth in these values that historically has been seen on a year over year basis. By doing a simple average of calendar years 2021 through 2023, the "base year" in Staff's proposal is essentially 2022. This approach skews the figures and ignores the most recent data that is known and measurable on the balance sheet as of September 2023.

Q. What factors other than inflation would impact the materials and supplies balance sheet values?

A. Materials and supplies balances are impacted by many things such as global supply and demand, tariffs, transportation, and raw materials, among others.

Q. Does the Company believe a 13.6 percent increase in the materials and supplies balance as stated in Staff/1300, Moore/6, line 6 and 7 is reasonable?

A. No. Staff witness Moore is using the wrong figures for his calculation. The 13.6 percent was derived by taking the difference between the Company's forecasted simple average of 2025 balance over the forecasted simple average 2023 balance. This is problematic for two reasons. First, using a simple average of 2025 is not the Test Year, so the value is irrelevant. Second, using a forecast as a comparison is not appropriate. Staff should have compared the Test Year value, which is derived using a 13-month AMA, with the September 2023 known and measurable balance.

Q. What is the percentage increase from September 2023 to the Test Year AMA value?

A. The increase is a reasonable 6.39 percent.

Q. If Staff witness Moore used the averaging method with the percentage increases versus using dollars, would that have been appropriate?

A. Yes. See Table 2 below, from Staff/1304, Moore/Workpaper, which calculates year-over-year percentage increases of the calendar year simple averages and highlights that these values have historically increased on an annual basis. In fact, over the 2021 through 2023 period, using the same three-year average method Staff applies to the dollar values, but to the observed year-over-year percentage increase, Staff's table shows the average percentage increase was 11.56 percent over the three years. Applying the 11.56 percent to the known balance as of September 2023, produces a materials and supplies Oregon-allocated balance of $24.6 million on a 13-month AMA basis for the Test Year, or $2.8 million higher than the Company's methodology and proposed amount in this case.

Table 2

Avg of Monthly Averages -Oregon			
		Incr %	3-Yr Avg %
2015	$7,826,360		
2016	$8,570,763	9.51%	
2017	$8,715,618	1.69%	
2018	$10,944,114	25.57%	
2019	$12,787,041	16.84%	
2020	$14,133,563	10.53%	
2021	**$14,350,704**	**1.54%**	
2022	**$17,085,869**	**19.06%**	
2023	**$19,490,075**	**14.07%**	**11.56%**
2024	$20,085,788	3.06%	
2025	$22,148,720	10.27%	

V. EDIT AMORTIZATION

Q. Please summarize the Company's Direct Testimony about EDIT amortization.

A. EDIT amortization is the result of the re-measurement of deferred income taxes following the 2017 federal income tax reform and reduces the EDIT regulatory liability, which is flowed through as a benefit to customers. The amortization included within the revenue requirement is $3.1 million.[27]

Q. Did the parties provide Opening Testimony addressing EDIT amortization?

A. Yes. Staff/200, Mondragon, addressed the Company's EDIT amortization.

Q. What is Staff's position regarding EDIT amortization?

A. Staff proposed increasing the EDIT Amortization from $3.1 million to $3.2 million, which reduces the federal tax expense by $100 thousand per year. In Staff's view, the $100 thousand adjustment balances returning the benefit to customers while also leaving the Company with a reasonable buffer of its normalization flow through.[28]

Q. How do you respond to Staff's position?

A. We accept Staff's proposed adjustment given the $100,000 increase in EDIT amortization does not cause the Company to trigger a normalization violation.

[27] NW Natural/1700, Walker/31-32.

[28] Staff/200, Mondragon/18-19.

VI. OPUC FEES

Q. What was included in the Company's revenue requirement for the OPUC fee?

A. The Company used the current rate at the time of filing, 0.43 percent of Company revenues.[29]

Q. Has the OPUC fee changed since filing the rate case?

A. Yes. In Order No. 24-054, entered on February 22, 2024, the Commission approved an increase, resulting in a new OPUC fee of 0.45 percent of Company revenues.

Q. Are Staff and the Company aligned on using the new OPUC fee percentage?

A. Yes. In Opening Testimony, Staff/800, Chipanera, Staff proposes increasing the fee to the newly approved 0.45 percent of Company revenues,[30] and NW Natural agrees.

VII. ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION ("AFUDC")

Q. Please summarize the Company's Direct Testimony about AFUDC.

A. The Company did not provide Direct Testimony on AFUDC.

Q. Did the parties provide Opening Testimony addressing AFUDC?

A. Yes. Staff/1400, Peng, addresses the Company's AFUDC.

Q. What are Staff's recommendations regarding AFUDC?

A. Staff recommends that the AFUDC rate cannot exceed the overall rate of return applied to rate base to ensure Oregon-jurisdictional rates are just and reasonable.

[29] NW Natural/1700, Walker/25.

[30] Staff/800, Chipanera/13.

As a result, Staff has proposed to cap the AFUDC rate at the Company's Oregon authorized rate of return and defer the excess portion as a regulatory asset for future recovery. Staff also recommends that we check for errors in the Company's capital structure calculation. "For example, a short-term and long-term debts in capital structure, because Oregon's capital structure does not include a short-term debt."[31] Last, Staff witness Peng states: "NWN complied with the OPUC policy to exclude CWIP in the rate base, because Oregon does not allow a utility to recover costs of a plant not yet placed in service in retail rates. The Company's AFUDC calculations meet FERC calculation procedures and meet Oregon regulatory requirements."[32]

Q. How do you respond to Staff's cap of AFUDC at the Company's rate of return on rate base?

A. The Company does not agree with Staff's position as we have not identified an Oregon statute, Oregon rule, or FERC rule stating that the AFUDC rate cannot exceed the overall rate of return.

Q. What do the FERC instructions say about AFUDC?

A. Subchapter F-Accounts of the Natural Gas Act, Part 201, instruction 17(b) states:

> The balances for long-term debt, preferred stock and common equity shall be the actual book balances as of the end of the prior year. The cost rates for long-term debt and preferred stock shall be the weighted average cost determined in the manner indicated in subpart D of part 154 of the Commission's Regulations Under the Natural Gas Act. The cost rate for common equity shall be the rate granted common equity in the last rate proceeding before the

[31] Staff/1400, Peng/18.

[32] Staff/1400, Peng/18.

> ratemaking body having primary rate jurisdiction. If such cost rate is not available, the average rate actually earned during the preceding three years shall be used. The short-term debt balances and related cost and the average balance for construction work in progress shall be estimated for the current year with appropriate adjustments as actual data becomes available.

Q. Do the FERC instructions not allow for the AFUDC rate to exceed the Company's rate of return on rate base?

A. No. The FERC instructions do say that the cost of common equity shall be the rate granted in the last rate proceeding before the rate making body having primary rate jurisdiction, but it says nothing about debt rates or the overall rate of AFUDC. The Company believes the Commission is our primary rate jurisdiction and dictates our cost of common equity.

Q. Does the Company adhere to the FERC instructions stated above? Specifically, how does the Company calculate AFUDC?

A. Yes, the Company adheres to the FERC instructions as stated in Staff's testimony.[33] The Company first utilizes short-term debt to finance its Construction Work In Process ("CWIP") balance. Once its short-term debt balance has been exhausted, it then uses a mix of long-term debt and equity in accordance with FERC instruction stated above. "The balances for long-term debt, preferred stock and common equity shall be the actual book balances as of the end of the prior year."[34] Each month, the Company accrues AFUDC on the CWIP balance using the rates and percentages in accordance with these rules.

[33] Staff/1400, Peng/18.

[34] Natural Gas Act, Part 201, Instruction 17(b).

Q. How does the Company respond to Staff's recommendation that the Company should check for errors in its capital structure calculation?

A. The Company has been calculating its capital structure in the same way for at least the last four rate cases which included short term debt, long term debt, and common equity. As part of the Company's accounting close process, the AFUDC calculations are checked for errors and get audited by our external auditors, Price Waterhouse Coopers. Staff has never had an issue with our capital structure calculation as it relates to AFUDC. Staff witness Peng stated from UG 344: "Staff reviewed Excel spreadsheet files with reference links and calculation formulas, and found that the Company's calculation of its AFUDC rates follow the FERC AFUDC rate formulas without deviation. The calculations assume that short-term debt is the first source of construction funding. If construction funding requirements exceed the balance of short-term debt, NWN assumes the requirements are met proportionally from long-term debt, preferred stock (if any) and common equity."[35]

Q. Does the Company agree with Staff that its "AFUDC calculations meet FERC calculation procedures and meet Oregon regulatory requirements"?

A. Yes.

[35] Docket No. UG 344, Staff/1100, Peng/13.

VIII. DECOUPLING

Q. Please summarize the Company's Direct Testimony about decoupling.

A. Similar to Staff's proposal in our prior rate case (UG 435),[36] the Company proposes to bifurcate existing residential customers from new premises residential customers as of the rate effective date, November 1, 2024. The new premises residential customers decoupling baseline was based off new premises usage data from January 2018 to December 2022, a five-year period, totaling an average use-per-customer ("UPC") of 449.4 therms per year. Every new premises residential customer that gets added to the gas system after November 1, 2024 will be decoupled at the new baseline of 449.4 therms per year. Along with the bifurcation, the Company also proposes to use a weighted average of the new and existing residential customers heating coefficient that converts heating degree days to therms for the weather normalization adjustment. This change also impacts weather adjusted rate mechanism ("WARM") because the same heating coefficient is used in that mechanism. The coefficients should be consistent because both rate mechanisms need to be aligned with the customer usage assumptions that are built into the revenue requirement for the Test Tear. If these mechanisms are not aligned, the Company would over or under collect normalized revenue requirement.[37]

[36] Docket No. UG 435, Staff/1300, Scala/19-28.

[37] NW Natural/1700, Walker/12-15.

Q. Did the parties provide Opening Testimony addressing Decoupling?

A. Yes. Staff/1900, Stevens and Coalition/100, Cebulko, address Decoupling. I respond to Staff, and NW Natural witness Wyman addresses the Coalition's testimony in NW Natural/3900, Wyman.

Q Please summarize Staff's position on Decoupling.

A. First, Staff recommends that the residential class, for purposes of decoupling, be permanently bifurcated going forward. Second, Staff believes "new" customers should be defined as any customer who joined the gas system beginning in 2018 and beyond. Last, Staff recommends the Company calculate separate heating coefficients between the two bifurcated groups of customers.[38]

Q. What is the Company's proposal as it relates to the bifurcated groups going forward?

A. The Company was not clear in Direct Testimony that our proposal includes that new residential customers will not be rolled into the existing residential customer class in each subsequent rate case. These customer classes will perpetually stay bifurcated unless significant changes are observed in usage data. New customers will not transfer into the existing customer class in future rate cases as Staff suggested in its Opening Testimony.[39] Therefore, the Company and Staff are aligned on this issue.

[38] Staff/1900, Stevens/20-24.

[39] Staff/1900, Stevens/21-22.

Q. Staff argues that new residential customers should be defined as a new premises residential customer that joined the system starting in 2018.[40] Do you agree?

A. No. The Company does not agree with Staff's position on defining new customers as of 2018. Staff's argument to define new premises customers as customers who joined the system starting in 2018 does not consider that those customers are already included in the existing residential class UPC of 660.2 therms calculated in NW Natural/1800, Wyman, and have been for two rate cases prior to the current case. These customers should not retroactively be moved into a different decoupling group. If the adjustment is going to be made, it should be on a prospective basis for new customers.

This adjustment would not only impact the existing residential UPCs, but it would also impact the revenue requirement as a whole, an analysis Staff did not provide. If Staff's approach were adopted, the Test Year in Staff's revenue requirement would not match Staff's position of new customers, which would violate the matching principle by failing to align the Test Year for both revenues and expenses. Overall, Staff's analysis is incomplete because Staff does not provide a newly calculated new premises customer UPC that implements Staff's recommendation, nor does Staff provide any analysis on how Staff's proposal would impact this rate case.

[40] Staff/1900, Stevens/23.

Q. Staff believes that the heating coefficients used for new and existing customers should be separate calculations and not a weighted average as the Company suggested.[41] How do you respond?

A. The Company believes using a weighted average is appropriate and would not skew the decoupling deferral in any material way. Furthermore, the Decoupling mechanism could be easily changed to incorporate two heating coefficients, but the WARM program could not.

Q. Please explain why the WARM program would be challenged to have two residential heating coefficients.

A. The Decoupling mechanism is merely an accounting exercise and could easily accommodate two heating coefficients. WARM, on the other hand, is a complex, real-time, mechanism that is conducted and coded in our customer information system. The WARM mechanism has been coded with only one heating coefficient for the residential class. Therefore, the Company has proposed a weighted average heating coefficient for both Decoupling and WARM to properly account for the differences in usage patterns between the two bifurcated groups. The heating coefficient will continue to be updated each rate case with the new weighted average amount.

[41] Staff/1900, Stevens/24.

IX. TEST YEAR REVENUES AND EXPENSES

Q. How does the Company forecast Test Year Revenues and Expenses?

A. The Company uses a variety of methods to calculate the forecasted Test Year Revenue and Expenses in the Revenue Requirement. NW Natural/1700, Walker lays out each of these calculations, which include the following: Sale of Gas, Miscellaneous Revenues, Gas Purchases, Uncollectible, O&M, Federal/State taxes, Property Taxes, Other Taxes, Net Utility Plant, and Other Rate Base Items.

Q. What is AWEC's position regarding the Test Year Revenues and Expenses?

A. AWEC witness Mullins uses the same arguments discussed above for the forecasted test year capital to adjust the Test Year's revenue and expenses. AWEC relies on the matching principle to argue that the Company should adjust the Test Year revenue and expenses from 12 months ending October 31, 2025 to 12 months ending October 31, 2024 to be consistent with rate base. AWEC makes this adjustment by choosing only two sections of the revenue requirement, margin revenues and non-labor O&M expenses, adjusting to 12 months ending October 31, 2024.[42]

Q. How do you respond to AWEC's position?

A. Although AWEC relies on the matching principle for its argument, it completely disregards all other components of revenue requirement that the Company calculates, as stated above. AWEC fails to match all revenues and expenses to 12 months ending October 31, 2024. Its analysis is thus incomplete and contrary

[42] AWEC/100, Mullins/22-25.

to the matching principle on which their argument is based. AWEC states "[i]ncreases in expenses that occur over time, for example, may be offset by increased sales. Lacking consistency between the two, rate payers may be required to pay for increased costs without recognizing the offsetting benefit from increased sales revenues."[43] AWEC's analysis lacks consistency by including a portion of expenses but excluding other pieces of revenue requirement such as other rate base items and taxes, to match all the revenues and expenses in the Test Year.

X. REMOVAL WORK IN PROGRESS ("RWIP") REMOVAL FORECAST

Q. Please summarize the Company's position on the RWIP removal forecast.

A. The Company has forecasted the cost of removals, via the RWIP account, through the Test Year based on a historical trend. The cost of removals is necessary to match additions that are added from October 2023 through the Test Year related to work where pipe and other assets are replacing existing infrastructure or a straight removal is occurring.

Q. What is RWIP and how does it work?

A. RWIP represents the net between the actual cost of removal and the release of the accrued removal cost liability that gets built up over time from the cost of removal portion of depreciation expense. The RWIP account is a contra liability account with a debit balance. Therefore, the RWIP account lowers accumulated depreciation and increases rate base. The debit balance of RWIP indicates that

[43] AWEC/100, Mullins/23.

the actual cost of removal is higher than the estimated amount we have included in our depreciation expense over time.

Q. Did the Company identify any errors in its cost of removal forecast?

A. Yes. The Company inadvertently double counted a portion of removal costs. This double counting increased rate base.

Q. Does the Company propose removing this double count in revenue requirement?

A. Yes. Later in this testimony, I update the revenue requirement for errors, which will remove the double count of RWIP.

Q. What is AWEC's position regarding the RWIP removal forecast?

A. AWEC witness Mullins recommends the Company retain the removals included on the "removals" tab of work paper NW Natural/1713, Walker.[44]

Q. How do you respond to AWEC's position?

A. First, I recognize that my work paper NW Natural/1713, Walker, may have caused some confusion, although I disagree with AWEC's overall recommendation.

The removals included on the "removals" tab of the above workpaper were from a forecast used in 2016. The removals included on the "removals" tab were made in error and should not have been included in the work paper. The RWIP forecast on the "Accum Deprec" tab is the correct forecast and it should be retained.

[44] AWEC/100, Mullins/26.

Q. What is the overall impact to NW Natural's error regarding the RWIP forecast?

A. The error caused an overstatement of rate base and once fixed will reduce revenue requirement by $618 thousand.

XI. RWIP ACCUMULATED DEFERRED INCOME TAX

Q. Please summarize the Company's position on RWIP accumulated deferred income tax.

A. The Company inadvertently failed to include the accumulated deferred income taxes related to forecasted RWIP. It is important to ensure accumulated deferred income taxes match the underlying rate base included in revenue requirement as to adhere to the matching principle. Adding the forecasted RWIP accumulated deferred income taxes will reduce rate base.

Q. Is the Company going to update its revenue requirement for the RWIP accumulated deferred income taxes?

A. Yes. Later in this testimony, I update the revenue requirement for errors, removal of one full time employee, and updated union contract, which will include the forecasted RWIP accumulated deferred tax component of rate base.

Q. What is AWEC's position regarding the RWIP accumulated deferred income taxes?

A. AWEC witness Mullins recommends that the accumulated deferred income taxes associated with RWIP should be included in rate base.[45]

[45] AWEC/100, Mullins/27-28.

Q. How do you respond to AWEC's position?

A. The Company agrees that the accumulated deferred income taxes associated with RWIP should be included in rate base on the same basis as RWIP is included in rate base due to the matching principle.

Q. What is the impact of including the forecasted RWIP accumulated deferred income taxes in rate base?

A. The impact to the Company's revenue requirement is a decrease of $276 thousand.

XII. ARAM ADJUSTMENT

Q. Please summarize the Company's position on the ARAM adjustment.

A. The Company included an ARAM adjustment to rate base of $3.1 million in the Test Year. After the Parties' Opening Testimony, the Company realized this adjustment had already been included in the Company's deferred income tax liability.

Q. Is the Company going to update its revenue requirement for the ARAM adjustment?

A. Yes. Later in this testimony, I update the revenue requirement for errors, which will remove the ARAM adjustment resulting in lower rate base.

Q. What is AWEC's position regarding the ARAM Adjustment?

A. AWEC witness Mullins identifies the double counting of the increase in rate base due to EDIT amortization.[46]

[46] AWEC/100, Mullins/31-32.

Q. How do you respond to AWEC's position?

A. The Company agrees with AWEC's position and will remove the double counting of $3.1 million to rate base.

Q. What is the impact of removing the ARAM adjustment?

A. The impact to revenue requirement is $297 thousand.

XIII. PRE-1981 FLOW THROUGH

Q. Did AWEC provide Opening Testimony regarding tax flow-through items?

A. Yes, AWEC issued data request 51 in this proceeding requesting background on two line items in the revenue requirement income tax calculation titled 'Pre-1981 Depreciation' and 'Pre-1981 Removal Costs.' The Company's reply to that request included references to Orders issued in Washington (UG-080546) and Oregon (UM 1335) proceedings that occurred in 2008 that authorized identical amortization of these items and also included the Company's amortization schedule indicating that amortization would be complete in 2027. AWEC's testimony on these flow-through items included references from the all-party settlement in Order in UM 1335, a note that the Company included the amortization of these items in the current filing, and concern on the timing and amount of these items.[47]

Q. What concerns did AWEC express in their testimony regarding 'Pre-1981 Depreciation'?

A. The first flow-through item, 'Pre-1981 Depreciation,' is an increase to income tax expense in the current filing of $7,350,000 on a gross basis, or approximately

[47] AWEC/100, Mullins/30.

$1.98 million on a net basis (using a 27 percent statutory tax rate). AWEC indicated that the settlement agreement in UM 1335 indicated an amortization period of approximately 25 years and the Company's initial application in UM 1335 had indicated an amortization period of approximately 20 years. The Order itself was silent with respect to the amortization period but was clear on the amount of the annual amortization. AWEC indicated that, based on their rough calculations, the amortization should have been complete sometime in 2023 and should therefore be excluded from inclusion in this current filing.[48]

Q. What concerns did AWEC express in their testimony regarding 'Pre-1981 Removal Costs'?

A. The second flow-through item, 'Pre-1981 Removal Costs,' is a reduction to income tax expense in the current filing of $1,175,000 on a gross basis, or approximately $317 thousand on a net basis (using a 27 percent statutory tax rate). AWEC indicated that the settlement agreement in UM 1335 authorized an annual amortization amount of $2,322,000 and that this larger amount should be included in this current filing.[49]

Q. Does the Company agree with AWEC's position regarding these flow-through items?

A. No. As I will explain in more detail below, the Company does not agree that the 'Pre-1981 Depreciation' flow-through item should be removed from the current

[48] AWEC/100, Mullins/31.

[49] AWEC/100, Mullins/30.

filing or that the 'Pre-1981 Removal Costs' item should be increased to the amount originally authorized in the 2008 UM 1335 Order.

Q. Please explain the Company's position with respect to the 'Pre-1981 Depreciation' flow-through item.

A. The amount included in the original filing in this proceeding is correct and should continue to be amortized through 2027. The Order in UM 1335 authorized recovery of the 'Pre-1981 Flow-Through' balance through annual gross amortization of $7,350,000. This amount has been included in annual amortization since the effective date of the order and will result in full amortization of this flow-through item during calendar year 2027. For reference purposes, NW Natural/3802, Walker to this testimony has been prepared to show the actual calendar year-end account balances from 2014 through 2023 and the expected balances for 2024 through 2027, as well as the changes in those balances for annual amortization and the remeasurement of balances in 2017 as a result of the federal Tax Cuts and Jobs Act. These actual recorded and reported balances are more precise and supportable than AWEC's rough calculations.

Q. Please explain the Company's position with respect to the 'Pre-1981 Removal Cost' flow-through item.

A. The amount included in the original filing in this proceeding is correct and should continue to be amortized through 2027. The Order in UM 1335 authorized recovery of the 'Pre-1981 Removal Cost' balance through annual gross amortization of $2,322,000. However, in UG 221, the annual amount was adjusted to $1,175,000, as explained in the Company's testimony from that docket:

> In Docket UM 1335, the Company modified its permanent difference amounts used to calculate the income tax provision. More specifically, the depreciation component related to pre-1981 assets was changed. In this case, the Company proposes to adjust the removal cost component to a level such that the related deferred taxes are amortized over the same period as the depreciation component.[50]

This adjusted amount has been included in annual amortization since the effective date of the Order in UG 221 and will result in full amortization of this flow-through item during calendar year 2027, which coincides with the full amortization of the depreciation flow-through item. For reference purposes, NW Natural/3802, Walker to this testimony has been prepared to show the actual calendar year-end account balances from 2014 through 2023 and the expected balances for 2024 through 2027, as well as the changes in those balances for annual amortization and the remeasurement of balances in 2017 as a result of the federal Tax Cuts and Jobs Act. These actual recorded and reported balances, as well as the references herein to previous proceedings, are more precise and supportable than AWEC's rough calculations.

XIV. CLOUD-BASED SOFTWARE CAPITALIZATION

Q. Please respond to Staff's request for clarification regarding whether license or hosting fees for cloud-based software projects are included in rate base.[51]

A. Under Accounting Standards Update ("ASU") 2018-05 "Customer's Accounting for Fees Paid in a Cloud Computing Arrangement (CCA)", the treatment of license or

[50] Docket No. UG 221, NW Natural/300, McVay-Siores/10.

[51] Staff/1000, Dyck/5; *see also* UG 490 OPUC DR 493.

hosting fees for cloud-based software depends on specific circumstances. Hosting or subscription fees for cloud-based software arrangements are expensed over the term of the contract and are not capitalized in rate base. However, implementation costs in a hosting arrangement, including the subscription fees for the first year, may be capitalized under the accounting rules. Thus, first-year license costs for such projects are included in rate base. This is in accordance with a 2019 FERC order on ASU 2018-15 to all jurisdictional public utilities and licenses, natural gas companies and centralized service companies.[52] In accordance with the ASU and the FERC ruling, for regulatory accounting, capitalized implementation costs are recorded as utility plant assets in Account 303 (Intangible Plant - Computer Software) and should be amortized over the term of the associated cloud computing arrangement in Account 403 (Depreciation Expense).

XV. UM 2309 AMORTIZATION

Q. Please describe UM 2309.

A. UM 2309 was a deferral application filed by AWEC when the Oregon Court of Appeals ruled the Climate Protection Program ("CPP") invalid. The deferral application asked NW Natural to defer costs allocated to Transportation and Special Contract customers for RNG that the Company was charging for compliance under the CPP. The Commission granted approval of the deferral in Order No. 24-086.

[52] FERC order in docket No. AI20-1-000, dated December 20, 2019.

Q. Please summarize AWEC's proposal for UM 2309 Amortization.

A. AWEC witness Mullins recommends all CPP costs being currently charged to Transportation and Special Contract customers be deferred and amortized back to customers via credits starting November 1, 2024.[53]

Q. How does the Company respond?

A. The Company believes that the purchased gas adjustment ("PGA") and associated filings is the best mechanism to accomplish AWEC's proposal. To the extent that the Commission agrees that these RNG costs should be amortized back to Transportation and Special Contract customers in light of the CPP invalidation, NW Natural would recover these deferred amounts from Sales customers in the upcoming PGA.

Q. What is the Company's proposal?

A. The Company proposes that we continue to defer revenues through October 2024 for the benefit of transport and special contract customers. The Company will make an advice filing in late July 2024 to amortize the June 2024 balance of the deferral, consistent with the PGA and associated filings. Simultaneously, NW Natural will recover these deferred amounts for RNG from Sales customers in the upcoming PGA. For RNG included in the upcoming PGA, NW Natural will change the allocation for RNG to Sales customers starting November 1, 2024 to be consistent with this approach. Any remaining deferred amounts will be captured in the 2025-26 PGA to the benefit of Transportation and Special Contract

[53] AWEC/100, Mullins/41-42.

customers. In the event that NW Natural will need to comply with future greenhouse gas policy in the coming year, NW Natural will likely need to change this allocation again to recover the costs of RNG from all entities for which NW Natural is the point of regulation.

XVI. UPDATED REVENUE REQUIREMENT

Q. Do the Company's responses to the Parties' Opening Testimony and discovery affect the proposed revenue requirement?

A. Yes. Through the Company's responses to the Parties' Opening Testimony and data requests, the Company has made a $2.58 million reduction to revenue requirement.

Q. Please identify all the specific items driving the increases and decreases in revenue requirement.

A. Highly confidential NW Natural/3803, Walker lists the items that were identified and agreed to in the Parties' Opening Testimony, conceded through discovery, recognized as an error contained in the Company's Direct Testimony, or updated by the Company in this Reply Testimony. NW Natural/3804, Walker provides the updated revenue requirement.

Q. Does this conclude your Reply Testimony?

A. Yes, it does.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibits of Kyle T. Walker

DECOUPLING / TEST YEAR / ACCOUNTING ADJUSTMENTS / REVENUE REQUIREMENTS EXHIBITS 3801 – 3804

June 4, 2024

EXHIBITS 3801-3804– DECOUPLING / TEST YEAR / ACCOUNTING ADJUSTMENTS / REVENUE REQUIREMENTS

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Kyle T. Walker

DECOUPLING / TEST YEAR / ACCOUNTING ADJUSTMENTS / REVENUE REQUIREMENTS EXHIBIT 3801

June 4, 2024

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 206

Please provide a narrative description of NWN's capital budgeting process including but not limited to development responsibilities, load study process, annual timing, and approval process.

Response:

The capital forecast is updated multiple times throughout the year. This forecast incorporates the most recent information based on requirements to maintain a safe and reliable system. Each year's budget is based on the forecast created in December, which is presented to and approved by the Board of Directors.

Finance facilitates the process with the five individual business units that provide those forecasts: Engineering, Customer Acquisition, Information Technologies, Facilities, and Transportation & Meter Shop. Review meetings take place with the managers, directors, and officers where the assumptions and forecast are reviewed and determined. Once approved, each group sends their forecast to Finance for inclusion in our overall forecast. The overall forecast is used to inform various groups on progress, adjust our planned spend and include impact the current and long-range forecast. Finance also facilitates a monthly review of current year variances against the approved budget.

Each business unit uses a bottom-up approach, where they determine required and run rate work in addition to identifying other projects that are needed. Detail is provided for applicants and projects.

Facilities:

Potential projects are identified by the business and/or Facilities department for consideration. The facilities projects steering committee reviews all requests, validates the potential need for the projects and determines if the projects should be added to the facilities 5-year roadmap for further evaluation.

Forecasts for each project are updated quarterly and reviewed by the Facilities Steering Committee, Finance team, and officers.

Transportation and Meters:

Vehicle replacements are evaluated based on a combination of vehicle vintage and mileage. Each year the list of vehicles that meet either the age or mileage limits are evaluated. That list along with department feedback creates the replacement list for the following year. Equipment and Trailers are determined to be replaced based on business need and, on a case-by-case basis. Tools are also requested by departments and are evaluated for business need and included on a list for purchasing the following year.

Meter needs are developed based on current meter inventory, customer growth forecasts, meter change outs, PCC changes as well as factoring in vendor lead times.

Customer Acquisition:

Services and Mains capital spend is forecasted based our customer growth forecast or footage of mains multiplied by estimated cost. Housing start projections from the Oregon Department of Economic Analysis are a key assumption when developing new customer projections. Permits are based on previous year actuals plus inflation. Meter installations are based on estimate number of units times cost per unit.

Engineering:

Planned projects are based on need, resource, and supply chain availability. A significant amount of work is driven by jurisdiction and compliance requirements. Planned capital work is typically identified in advance based on long range plans, Facility assessment reports, Equipment studies, safety plans or DIMP & TIMP plans. Prioritization is given to projects based on urgency or feedback from operations personnel. Nearer term planned work can be due to equipment unexpectedly failing or showing near end of life, avoidance of potential pipeline safety impact due to natural forces, and jurisdictional franchise obligations. Larger, discrete projects are individually assigned projects in our project management office and have capital spend budgets and expected in-service dates that are managed through the duration of the project. Those are all individually tracked through our forecasting process. Forecasts for some categories of work are based on historical spend trends.

IT&S:

The collection of projects reflects various business needs. Enterprise Applications projects are driven by new or changes to existing systems to support new or changed compliance requirements, or to support new business needs. Information Security projects follow the cybersecurity strategic plan. The Enterprise Architecture forecast follows the IT&S 5-year strategic plan and are typically new capabilities driven by business needs focusing on building resilient modern platforms, optimizing value of existing platforms and building new

capabilities as required. Network, Infrastructure and Service delivery typically entail technical refresh cycles. Finally Operational Technology represent engineering projects that require IT&S execution, so this forecast follows the needs and projections of some of the engineering's forecasted capital plan.

The business units where applicable coordinate with the Portfolio Management Committee which meets to discuss, review, prioritize and approve funding for projects and determine if it should be added to the portfolio. Considerations included for discussion are urgency, capital spend and resource constraints. The business units triangulate with the portfolio management committee to ensure that projects are approved and being included in the budget/forecasting process. Following approval, projects are included into the forecast cycle.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Kyle T. Walker

DECOUPLING / TEST YEAR / ACCOUNTING ADJUSTMENTS / REVENUE REQUIREMENTS EXHIBIT 3802

June 4, 2024

NW Natural
UG 490
Exhibit 3802

	Year-End Account Balance [a]		Change during the Calendar Year				
2014	50,694,812.38						
2015	46,680,812.38		4,014,000.00	[c]			
2016	42,666,726.38	[b]	4,014,086.00	[c]	4,014,086.00	[c]	Change for Amortization
2017	21,265,384.38	[b]	21,401,342.00		17,387,256.00	[d]	Change for TCJA Remeasurement
2018	19,056,958.38		2,208,426.00	[e]	21,401,342.00		
2019	16,848,532.38		2,208,426.00	[e]			
2020	14,640,106.38		2,208,426.00	[e]			
2021	12,431,680.38		2,208,426.00	[e]			
2022	10,223,254.38		2,208,426.00	[e]			
2023	8,014,828.38		2,208,426.00	[e]			
2024	5,806,402.38		2,208,426.00	[e]			
2025	3,597,976.38		2,208,426.00	[e]			
2026	1,389,550.38		2,208,426.00	[e]			
2027	(0.00)		1,389,550.38	[f]			

[a] Actual year-end account balance 2014 through 2023. Expected year-end balances 2024 through 2027.

[b] These balances are reported in our annual 10k report. Here is an example from the 2017 report:

> At December 31, 2017 and 2016, regulatory income tax assets of $21.3 million and $43.0 million, respectively, were recorded, a portion of which is recorded in current assets.

[c] The annual changes in these years, at corporate rates in effect before 2018, reflect the amortization of the 'Pre-1981 Depreciation' and 'Pre-1981 Removal Cost' flow-through items as follows:

'Pre-1981 Depreciation'	'Pre-1981 Removal Costs'	Combined Total	
7,350,000	(1,175,000)	6,175,000	*Gross annual amortization*
39.40%	39.40%	39.40%	*Blended statutory tax rate*
2,895,601	(462,902)	2,432,699	*Net amortization*
165.01%	165.01%	165.01%	*Tax gross up rate*
4,777,900	(763,814)	4,014,086	*Annual amortization in income tax*

[d] This remeasurement of the flow-through items as a result of the 2017 Tax Cuts and Jobs Act (TCJA) was disclosed during the UG344 general rate case. Here is an excerpt from that disclosure (the total was not in the original / added here for ease of reference):

Account		Gross Balance	Original Measurement	Remeasured	Change
283015	Flowthrough	(3,865,263)	(3,865,263)	(2,126,547)	(1,738,716)
283016	Flowthrough	(34,787,377)	(34,787,377)	(19,138,932)	(15,648,445)
					(17,387,161)

[e] The annual changes in these years, at corporate rates in effect after 2017, reflect the amortization of the 'Pre-1981 Depreciation' and 'Pre-1981 Removal Cost' flow-through items as follows:

'Pre-1981 Depreciation'	'Pre-1981 Removal Costs'	Combined Total	
7,350,000	(1,175,000)	6,175,000	*Gross annual amortization*
26.34%	26.34%	26.34%	*Blended statutory tax rate*
1,936,193	(309,527)	1,626,666	*Net amortization*
135.76%	135.76%	135.76%	*Tax gross up rate*
2,628,653	(420,227)	2,208,426	*Annual amortization in income tax*

[f] The remaining balance is fully amortized in calendar year 2027

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Kyle T. Walker

DECOUPLING / TEST YEAR / ACCOUNTING ADJUSTMENTS / REVENUE REQUIREMENTS EXHIBIT 3803

REDACTED

Under Modified Protective Order No. 23-480, this exhibit is highly confidential in its entirety and has been redacted.

June 4, 2024

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Kyle T. Walker

DECOUPLING / TEST YEAR / ACCOUNTING ADJUSTMENTS / REVENUE REQUIREMENTS EXHIBIT 3804

June 4, 2024

NW Natural
UG 490 - Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2025
Exhibit 3804
($000)

Line No.		Test Year: Filed Rate Case Results (a)	Adjustments (b)	Rounding to OPUC Model	Test Year Adjusted (c)	Margin Change [a] (d)	Results @ 10.1% ROE (e)	Corporate Activity Tax (f)	Proposed Total (g)
	Operating Revenues								
1	**Sale of Gas**	$915,275	$0	$0	$915,275	$151,684	$1,066,959	$661	$1,067,620
2	**Transportation**	16,609	0	0	16,609		16,609	0	16,609
3	**Decoupling**	0	0	0	0		0	0	0
4	**WARM**	0	0	0	0		0	0	0
5	**Miscellaneous Revenues**	4,005	0	0	4,005		4,005	0	4,005
6	**Total Operating Revenues**	935,889	0	0	935,889	151,684	1,087,573	661	1,088,234.322
									0
	Operating Revenue Deductions								0
7	**Gas Purchased**	405,328	0	0	405,328		405,328	0	405,328
8	**Uncollectible Accrual for Gas Sales**	4,494	0	0	4,494	745	5,239	0	5,239
9	**Other Operating & Maintenance Expenses**	237,051	(465)	0	236,587		236,587	0	236,587
10	**Total Operating & Maintenance Expense**	646,874	(465)	0	646,409	745	647,153	0	647,153
									0
11	**Federal Income Tax**	(2,499)	263	0	(2,236)	28,476	26,241	0	26,241
12	**State Excise**	4,529	103	0	4,632	11,153	15,785	643	16,428
13	**Property Taxes**	31,795	0	0	31,795		31,795	0	31,795
14	**Other Taxes**	34,888	0	0	34,888	4,185	39,073	18	39,092
15	**Depreciation & Amortization**	170,820	(595)	0	170,225		170,225	0	170,225
16	**Total Operating Revenue Deductions**	886,406	(693)	0	885,713	44,560	930,273	661	930,934
									0
17	**Net Operating Revenues**	$49,483	693	0	$50,176	$107,124	$157,301	$0	$157,301
									0
	Average Rate Base								0
18	**Utility Plant in Service**	$4,120,671	($4,107)	$0	$4,116,563		$4,116,563	0	4,116,563
19	**Accumulated Depreciation**	(1,638,721)	(2,541)	0	(1,641,262)		(1,641,262)	0	(1,641,262)
20	**Net Utility Plant**	2,481,950	(6,648)	0	2,475,302	0	2,475,302	0	2,475,302
									0
21	**Aid in Advance of Construction**	(6,499)	0	0	(6,499)		(6,499)	0	(6,499)
22	**Customer Deposits**	(755)	0	0	(755)		(755)	0	(755)
23	**Gas Inventory**	43,889	0	0	43,889		43,889	0	43,889
24	**Leasehold Improvements**	18,596	0	0	18,596		18,596	0	18,596
25	**Materials & Supplies**	21,810	0	0	21,810		21,810	0	21,810
26	**EDIT Adjustments to Rate Base**	3,100	(2,876)	0	224		224	0	224
27	**Accumulated Deferred Income Taxes**	(447,889)	(2,876)	0	(450,765)		(450,765)	0	(450,765)
28	**Cash Working Capital**	22,159	0	0	22,159		22,159	0	22,159
									0
29	**Total Rate Base**	$2,136,361	(12,400)	0	$2,123,961	0	$2,123,961	$0	$2,123,961
30	**Rate of Return**	2.316%			2.362%		7.406%		7.406%
31	**Return on Common Equity**	-0.08%			0.01%		10.10%		10.10%

Total Revenue Requirement
$152,345

[a] Margin increase is calculated by multiplying Test Year Rate Base (line 28 column c) by the Rate of Return (line 29 column e) and comparing the result to Test Year Operating Revenues (line 17 column c). The difference is then grossed up for tax and shown in line 1 of column d. Associated taxes and uncollectibles are calculated based on the revenue increase and the tax rates and uncollectible average as used in this model.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Reply Testimony of Robert J. Wyman

CUSTOMER AND NORMALIZED VOLUME FORECAST, LONG-RUN INCREMENTAL COSTS, AND RATE DESIGN/SPREAD EXHIBIT 3900

June 4, 2024

EXHIBIT 3900 – REPLY TESTIMONY – CUSTOMER AND NORMALIZED VOLUME FORECAST, LONG-RUN INCREMENTAL COSTS, AND RATE DESIGN/SPREAD

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I. INTRODUCTION AND SUMMARY

Q. Are you the same Robert J. Wyman who presented Direct Testimony in this proceeding on behalf of Northwest Natural Gas Company dba NW Natural ("NW Natural" or the "Company")?

A. Yes, I presented NW Natural/1800, Wyman.

Q. What is the purpose of your Reply Testimony in this proceeding?

A. I summarize and respond to the issues raised in Opening Testimony by Eric Shierman, Bret Stevens and Michelle Scala on behalf of Commission Staff ("Staff"), Bradley G. Mullins on behalf of the Alliance of Western Energy Consumers ("AWEC"), John Garrett on behalf of the Oregon Citizens' Utility Board ("CUB"), and Bradley Cebulko on behalf of the Coalition[1] ("Coalition") (collectively referred to here as the "Parties") on the topics of the weather normalized use-per-customer load forecast ("UPC Forecast"), Long-Run Incremental Cost ("LRIC") study, and rate spread and rate design proposed by the Company.

Q. Please summarize your Reply Testimony.

A. First, I respond to Staff's testimony regarding the Company's load forecast methodology, referred to here as the UPC Forecast. Second, I review and respond to Staff's and AWEC's testimony regarding the LRIC study methodology. Third, I discuss the Company's rate design proposals and respond to Parties'

[1] The Coalition includes the Coalition of Communities of Color, Climate Solutions, Verde, Columbia Riverkeeper, Oregon Environmental Council, Community Energy Project, and Sierra Club.

testimonies on the matter. Finally, I review and respond to Staff's and AWEC's rate spread proposals.

II. UPC FORECAST

A. Overview of Company's UPC Forecast Methodology

Q. Please briefly describe the purpose of the UPC Forecast.

A. The UPC Forecast uses a time series regression model to estimate the Company's weather normalized usage, or load. The forecast is used to calculate revenues at existing rates in the proposed revenue requirement for the Base Year and Test Year, as presented in NW Natural/1700, Walker and NW Natural/3800, Walker. It is also used to create the design day load factor, which is an important input to the LRIC study.

Q. Please summarize the Company's UPC Forecast methodology.

A. The UPC Forecast estimates weather normalized usage for the Residential and Commercial rate classes on a per customer basis. The forecast relies on the relationship between weather (including temperature, which is translated into heating degree days, or "HDDs", as well as other variables such as precipitation and wind speed) and load by rate schedule and time of year (measured in daily increments).[2] I used load data on a billing cycle basis, and matched actual

[2] The degree day is a unit of measurement based on the difference between the average temperature for a day and a base set point. Degree days are additive in that the sum of the daily degree days over the course of the month is taken to represent that month's weather. The degree day is a common unit of measurement that allows for an analysis of increasing usage as a function of increasingly colder weather. The Company used a 59-degree and 58-degree Fahrenheit base set point for residential and commercial rate classes, respectively. The set point is taken to be the temperature at which customers begin to use energy for heating purposes.

weather observations with the days between cycle meter read dates. This process ensures actual usage recorded for each billing period is appropriately matched to the observed weather for the same period. I then created a weighting of the number of days, customers, and HDDs associated with each billing cycle for each schedule in the Residential and Commercial customer classes. Using an Autoregressive Integrated Moving Average ("ARIMA") time series model, I tested four categories of coefficients that explain usage per customer per day as a function of: (1) weather, including heating usage per HDD per day; (2) base usage by month; (3) non-weather factors that account for the shift in energy usage patterns after the COVID-19 pandemic as well as energy efficiency from ongoing demand side management; and (4) temporal effects on usage from prior periods.[3] Finally, I used the estimated coefficients to build the weather normalized UPC Forecast on a daily basis using the 25-year HDD benchmark.[4]

Q. Please summarize the Company's ARIMA model specification selection process.

A. For every rate schedule modeled, I relied foremost on Durbin-Watson test statistics, r-squared values, and root mean squared error results to assess model

[3] An ARIMA model is a type of time series model specification for data observations that occur across equal intervals of time. The model is used to help forecast future values in the series by each value against a chosen number of lagged values (the autoregressive term); lags of moving averages may be chosen as well. ARIMA models are denoted as ARIMA (p,d,q) where p is the number of time lags in the autoregressive term; d indicates the number of times the independent variables are differenced; and q is the number of lags of moving averages. Together, these terms help fit the time series model by accounting for different temporal effects on usage that are associated with prior periods.

[4] See also NW Natural/1800, Wyman/7-9.

efficacy and choose appropriate ARIMA *p* autoregressive time lags and *q* lags of moving averages terms.[5] I relied on the Augmented Dickey-Fuller test to determine the appropriateness of differencing load forecast data variables with the ARIMA *d* term to ensure model stationarity. Further, I plotted model residuals to check for non-uniformity. I consulted the Akaike Information Criterion ("AIC") and the Bayesian Information Criterion ("BIC") metrics to evaluate the performance of models under varying *p* and *q* term specifications against one another.[6]

Q. Did the Company implement any recommended modifications to the UPC Forecast model specification that Parties raised in its last general rate case (UG 435)?

A. Yes. I incorporated recommendations put forth by Staff and CUB into this iteration of the UPC Forecast. These recommendations included examination of the impacts of the COVID-19 global pandemic, inclusion of additional explanatory weather variables, as well as the addition of a control for days of the week.

B. Reply to Staff Testimony Regarding Company's UPC Forecast Methodology

Q. Did any of the Parties review the Company's UPC Forecast methodology?

A. Yes. Staff reviewed the Company's forecast and indicated it found "no major concerns" with the forecast methodology and noted that the Company "uses

[5] The Durbin-Watson test statistic, which is a test for autocorrelation, takes a value from 0 to 4. A value of 2 indicates no autocorrelation. A value less than 2 indicates positive autocorrelation, and a value greater than 2 indicates negative autocorrelation.

[6] When comparing models with the same variables but different *p* or *q* terms, in general the model with the lower AIC and BIC metric is preferable. See also NW Natural/1800, Wyman/10-21.

industry standard methodologies and is receptive to feedback regarding model improvements."[7] AWEC, CUB, and the Coalition did not provide Opening Testimony on this topic.

Q. Did Staff provide feedback for potential improvements to the Company's UPC Forecast methodology?

A. Yes. Staff made the following recommended changes to the Company's UPC Forecast methodology with the goal of "improving transparency and model flexibility":

1. Algorithmically parameterize ARIMA models as baseline with any deviations justified in testimony.
2. Attempt to use non-linear weather terms when applicable and discuss rationale for excluding these terms.
3. Use monthly dummies as opposed to the natural logarithm of the number of weekend and holiday days in each month.
4. Drop variables with very small effects.

Further, Staff recommended a unique set of model specification changes for each rate class in the UPC Forecast.[8]

Q. How did Staff implement its recommended methodological changes?

A. Staff used an algorithm to automatically select an ARIMA(p,d,q) model parameterization for each rate class. This process, in Staff's view, produced

[7] Staff/1900, Stevens/2-3.

[8] *Id*., Stevens/3.

satisfactory results for RS 2 Residential, RS 27 Dry-Out, and RS 31 Commercial Sales Firm. Where the algorithm performed poorly in parameterizing the overall Commercial class, RS 3 Commercial, and RS 32 Commercial Sales Firm, by forecasting summer load higher than historical consumption norms, Staff overrode the model and selected the parameterization. Staff's manual parameterization introduced multiplicative seasonal components to the ARIMA model in the form of ARIMA(p,d,q)*(P,D,Q)s where s indicates the number of lagged multiplicative seasonal autoregressive P and moving average Q terms, seasonally differenced D times. Staff indicates that where applied, the seasonal differencing parameters account for the seasonal variation in rate class usage instead of the monthly indicator variables which it recommends be removed from the model specification.

Staff recommended modifications to the model specifications that include, depending on the rate class: Changes to (or exclusion of) the monthly indicator variables, addition of a squared HDD term to control for the non-linear effects of weather, and exclusion of various explanatory variables (notably: weather terms) that Staff found did not produce meaningful coefficients.[9]

Q. How did Staff evaluate the performance of its methodological changes?

A. Staff examined the fit of the models as measured by the AIC and BIC metrics, which I referenced above. Staff examined the distribution of residuals between

[9] *Id*., Stevens/4-19.

its models and the Company's, with a distribution closer to a standard distribution indicating a preferable model specification.[10]

Q. How does the Company's evaluation of the performance of its models differ from Staff's evaluation?

A. In addition to the AIC and BIC metrics, I relied on Durbin-Watson test statistics, r-squared values, and mean squared errors to assess my choice of variables in order to optimize model estimation. I also relied on the Augmented Dickey-Fuller test to determine the appropriateness of differencing load forecast data variables with the ARIMA *d* term to ensure model stationarity.[11] Finally, I performed a "backcast" test on each of my models. A backcast test evaluates how well a model can estimate actual known out-of-sample values using historical (actual) data. I performed an analysis using three backcast tests of varying data vintages to compare model forecast performance against actual load data, for both residential and commercial rate schedules. Models are evaluated against each other by calculating and comparing mean absolute percent error ("MAPE") value to test model accuracy.

[10] *Id*., Stevens/4.

[11] Non-stationarity in the UPC Forecast model variables can occur when their statistical properties vary over time. A utility's customer count is an example, for instance, because it generally increases over time but not at a constant rate. New customers spurred by housing construction are more likely to start service in summer months than winter months. For each of the Company's rate schedule models, the Augmented Dickey-Fuller test indicated model stationarity using the selected *p* and *q* terms. Inclusion of the differencing d term degraded all or nearly all test statistics, and therefore I did not employ the *d* term in any model specification.

Q. Did Staff calculate a proposed adjustment to revenue requirement based on its recommended changes?

A. No. Staff estimated regression results for each of the rate schedules in the Company's UPC Forecast but did not evaluate the impact of its results and recommendations on the Company's revenue requirement. Staff notes that it is working with the Company to implement its recommended changes, and that it "does not anticipate that these changes will have a large impact on the proposed rates in this case but it contends that these changes will improve the Company's load forecast."[12]

Q. Has the Company attempted to replicate Staff's results?

A. Yes. Staff produced its regression results using *R*, an open-source statistical computing software, while the Company used a statistical software package called Stata. Using Stata, I have reproduced forecast results for the residential rate class that are close to – but not precisely the same – as Staff's results. Upon conferring with Staff, we believe the difference in results could lie in how *R* and Stata treat the ARIMA *d* differencing term introduced in some of Staff's models; whereas *R* produces a forecast value for the dependent variable, Stata produces a dependent variable forecast value that represents the difference from the prior period forecast value. Staff and the Company have not been able to fully reconcile the models between the two software systems.

[12] Staff/1900, Stevens/3.

Q. What is the Company's response to Staff's recommendations?

A. The Company agrees with Staff's characterization that the Company is receptive to feedback regarding model improvements and that nearly all econometric models have room for improvement. I believe that model replicability and simplicity are important so that results and test statistics can be calculated across software platforms, and so that others can independently verify the results. Further, out-of-sample backcast testing conducted across varying historical data vintages, with comparison of the MAPE across forecasted model results, is a useful tool for understanding model forecasting performance and fit. This is in addition to the examination of forecast residuals presented by Staff, as well as other metrics such as the Durbin-Watson test statistic.

Staff did not propose a revenue requirement adjustment. Given Staff's position that any adjustment would not be significant, as well as the remaining issues of replicability and the need for additional testing of forecast performance and fit (e.g., backcast testing), the Company proposes to further examine Staff's recommendations prior to filing its next general rate case at which time it will address whether it has implemented (or explain its reasoning for not implementing) each recommendation. It is important to fully understand the effects of Staff's recommendations and the impact on the UPC Forecast results – as Staff noted, in the process of implementing its first recommendation, its automatically parameterized ARIMA models derived by an algorithm in *R* produced a summer season forecasts that were either unrealistic or higher than historical consumption for the Commercial rate class as a whole, as well as the

Small Commercial sub-class, and RS 32 Commercial Sales Firm.[13] The Company's proposal is consistent with its commitment to improving its model, as well as prior practices whereby the Company examined and implemented Staff recommendations in subsequent general rate case filings both for this proceeding (UG 490) as well one prior (UG 435).

III. LONG-RUN INCREMENTAL COST (LRIC) STUDY

A. Overview of Company's LRIC Study

Q. Please briefly describe the purpose of the LRIC study.

A. The overall objective of the LRIC study is to apportion the incremental revenue requirement to rate schedules based on each schedule's specific cost to serve. The LRIC study methodology presented in my Direct Testimony is an economics exercise that evaluates how much of the Company's incremental capital investment and carrying costs, and operations and other expenses required to serve its customers, can be directly and indirectly attributable to each rate schedule. By understanding the long run incremental costs by rate schedule, the LRIC study methodology apportions a utility's storage, transmission, and distribution costs, as well as operating expenses (i.e., all of the components of revenue requirement) based on cost causation. The costs and expenses that form a basis for the LRIC study follow the Company's Test Year for the 12 months ended October 31, 2025.

[13] *Id*., Stevens/7, 9 and 17.

After allocating all revenue requirement cost elements, the LRIC study calculates the relative ratio of revenue to incremental costs for each rate schedule at present rates. This ratio is used to understand cross-subsidies between rate schedules at current rates and is used by the Company to inform its rate spread and rate design proposals.

Q. Did your LRIC study methodology differ from the methodology used in the Company's last rate case filing, UG 435?

A. Yes. The LRIC study methodology I presented in my Direct Testimony is similar to the methodology used in the Company's last rate case filing, UG 435. There are two notable modifications, both of which are based on Staff recommendations. The modifications are updates to:

- The maximum daily delivered volume ("MDDV") calculation for design day load factor development, in order to account for changing incremental customer counts through time; and
- The system core main allocation, which now includes interruptible peak day deliveries, adjusted with a 50 percent credit, to calculate weighted peak day deliveries for all rate schedules as a basis for core main cost assignment.[14]

[14] NW Natural/1800, Wyman/33.

B. Reply to Parties' Testimony Regarding LRIC Study Methodology

Q. Did Parties provide feedback on the Company's LRIC study methodology and implementation?

A. Yes. Staff and AWEC provided feedback regarding the Company's filed LRIC study methodology and implementation.

Q. What is Staff's response to your LRIC study modifications based on its recommendations from UG 435?

A. Staff indicates that it examined the Company's LRIC study workpapers and with regards to Staff's recommendations, "it appears to Staff that this feedback was implemented effectively."[15]

Q. What is Staff's response to the Company's overall LRIC study implementation in this proceeding?

A. Staff provides no other feedback with regards to the LRIC study methodology or implementation but indicates it may update its position based on other parties' feedback.[16]

Q. What is AWEC's response to the Company's LRIC study methodology?

A. AWEC raises general concerns and proposes several methodological changes to the Company's LRIC study. AWEC asserts that the Company's LRIC study:

[15] Staff/1800, Shierman/4.

[16] *Id*.

1. Uses a "peak and average" allocation method, which tends to overweight volumes relative to demand compared to an "average and excess" allocation method;[17]
2. Applies a 50 percent demand discount for interruptible rate schedules for some investment types, which does not reflect the risk of service interruption that these customers take and the benefits they provide to the system,[18] and further does not apply any interruptible rate schedule demand discount for regulating equipment and compressor station investments;[19] and
3. Applies an inconsistent methodology for service line allocation that "treats small and large customers differently when allocating costs of services."[20]

I will address each of these points in turn below.

1. *"Peak and average" versus "average and excess" allocation methodology*

Q. What is AWEC's concern with regards to the "peak and average" allocation methodology?

A. AWEC asserts that the Company's LRIC study uses a "peak and average" allocation methodology which is "generally unfavorable towards high volume customer classes relative to other methods such as the average and excess method" and that it "tends to overweight volumes relative to demand."[21] AWEC

[17] AWEC/100, Mullins/43.

[18] AWEC/100, Mullins/45-46.

[19] AWEC/100, Mullins/45.

[20] AWEC/100, Mullins/46.

[21] AWEC/100, Mullins/43-44.

argues that there are issues within the framework of this methodology that drive its LRIC study recommendations.

Q. Does the Company's LRIC study use the "peak and average" allocation methodology or the "average and excess" allocation methodology, or both?

A. The Company uses both methodologies. The design day load factor, which is a ratio measure of each rate schedule's contribution to the design day peak load, is one key input into the LRIC study. A low load factor ratio indicates that a rate schedule has high peaking load relative to normalized average usage (i.e., it indicates the rate schedule has high weather sensitivity as load peaks during cold weather events). A high load factor ratio indicates less weather sensitivity and more predicable base load usage throughout the year. The load factor is the basis for the design day (peak) and annual throughput (average) allocator that the LRIC study uses to allocate (in full or in part) distribution mains and assets, and transmission main investment to each rate schedule. The "peak and average" allocator is a weighted ratio of each rate schedule's contribution to the load factor-derived peak day deliveries and average throughput.[22]

The load factor is also the basis for the "average and excess" allocator that the LRIC study uses to distribute system core mains costs to the rate schedules based on two allocations: total throughput and firm demand. The total throughput allocator is based on the system design day load factor (i.e., the

[22] *See*: "UG 490 - Exh. 1801 - WP6 - Long-Run Incremental Cost Study (LRIC) Model," tab "LRIC Allocators." The design day peak and average allocator is labeled, *Dist-1*.

"average") and distributes costs across all schedules. The firm demand allocator is based on one minus the system design day load factor (i.e., the "excess") and similarly distributes costs across all rate schedules.[23]

I also employ a methodology similar to "average and excess" in this LRIC study for underground gas storage plant costs. I allocated these costs to sales customers only, using a ratio based on Test Year average winter sales that exceed Test Year average summer sales. This measure allocates costs based on contribution to average peak loads compared to a period of average base loads.[24]

Q. What is the Company's response to AWEC's statement that "the peak and average method is not necessarily consistent with cost causation principles, particularly where volumes are overweighted in the allocation factor calculation?"[25]

A. The Company agrees that, on its own, the "peak and average" allocator does not fully capture the entirety of the system's cost causation among all rate schedules, which is why I also employ the "average and excess" and "winter to summer average excess" allocation methodologies in my LRIC study. The Company also agrees that its natural gas system is built based on design day demands, which is why the design day load factor is a key input into the LRIC study cost causation modeling methodology. It follows, however, that cost causation for

[23] *Id*. The system core mains average and excess allocators are labeled *Dist-5* and *Dist-6*.

[24] *Id*. The underground storage average winter to summer sales excess allocator is labeled *Stor-1*.

[25] AWEC/100, Mullins/43.

some investments such as a portion of distribution mains and transmission mains are allocated based on demand throughput based on a rate schedule's contribution to capacity needs. It also follows that cost causation for some investments, such as a portion of distribution (system core) mains and underground storage, are better allocated based on a rate schedule's contribution to capacity demands at peak times. The Company uses both methodologies to balance the assignment of cost causation among disparate investment categories from high volume to lower volume, but peakier, customer classes.

2. Interruptible customer demand discount allocation

Q. What is the interruptible customer demand discount allocation?

A. I introduced the interruptible customer demand discount allocation in the LRIC study filed in this proceeding in response to a Staff recommendation in UG 435. This allocation recognizes, as Staff asserted in testimony, that interruptible customers "receive tangible benefits from peak day planning investments" because they are "seldom, if ever interrupted" and therefore should be allocated a portion of these resource costs.[26] The Company agreed to Staff's recommendation to include an allocation to interruptible customers at 50 percent of the standard firm demand allocation as a reasonable method for allocating some costs that it had previously only allocated to firm customers.[27]

[26] In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision, Docket No. UG 435, Staff/1600, Gibbens/13, lines 11-14 (April 22, 2022).

[27] NW Natural/1800, Wyman/33.

Q. What categories of costs does the Company's LRIC study apply to interruptible customers that it had previously only allocated to firm customers?

A. The Company's LRIC study applies the interruptible customer demand discount to system core mains costs using allocators labeled *Dist-5* and *Dist-6*. I also apply the discount to underground storage costs using an allocator labeled *Stor-1*.

Q. Does the Company's LRIC study have allocators for distribution and mains related costs for which it does not apply the 50 percent discount?

A. Yes. AWEC notes that the Company's *Dist-1* allocation factor, which does not provide the 50 percent discount, is applied to investments for other distribution costs including measuring and regulating equipment and compressor stations.[28] Additionally, I assign the remainder of distribution mains costs not subject to the 50 percent discount using direct allocation developed based on studies I conducted using Company data such as job orders, engineering and other Geographic Information Systems ("GIS") data, accounting data, and billing and usage data.[29]

[28] AWEC/100, Mullins/45.

[29] NW Natural/1800, Wyman/30. These allocators are labeled *Dist-2*, *Dist-3*, *Dist-4*, and *Dist-7* in the Company's LRIC study.

Q. How does the Company respond to AWEC's position that the *Dist-1* allocation factor should provide an interruptible rate schedule demand discount for costs such as regulating equipment and compressor stations?

A. I am agreeable to treating costs allocated by *Dist-1* in the same manner as *Dist-5* and *Dist-6* by applying an interruptible rate schedule demand discount (but not, as I explain below, a full discount). Regulating equipment and compressor station investments, I will note, are not just design capacity assets but also help to manage natural gas flows throughout the winter (and the entire year) and therefore do provide benefit for interruptible customers.

Q. Does AWEC agree with the 50 percent interruptible rate schedule demand discount?

A. No. AWEC states "customers that choose to take services on interruptible schedules are fully interruptible, not fifty percent interruptible" and, therefore, it is "most appropriate to provide a demand discount equal to 100% of the customer's requirements."[30]

Q. How does the Company respond to AWEC's assertion that the interruptible rate schedule demand discount should be 100 percent?

A. The LRIC study is a theoretical economic costing exercise that attempts to estimate the point where customers, either individually or as part of a rate class, are paying the costs associated with their service as a basis for discussions of price setting and rate spread. The Company agrees that interruptible customers

[30] AWEC/100, Mullins/45-46.

provide system planning benefits and these benefits are reflected in the rates that are charged to these customers. Valuing and assigning these benefits are not straightforward and raise the question of how (and to what extent) to allocate costs based on requirements and obligations in the tariffed rate compared to how the system is used in practice. On one hand, interruptible customers benefit from the reliability and capacity built for the design day standard of the system. Not all interruptions occur due to capacity constraints from peaking on the system under normal operating conditions; some occur for reasons outside the utility's control (e.g., third-party damage to infrastructure). On the other hand, the Company notes that regardless of the number of demand response events, interruptible customers do present a demand side resource for the sole reason they *can* be interrupted to alleviate supply and capacity constraints.

Q. What is the Company's response to AWEC's recommendation?

A. The Company believes its methodology for allocating distribution costs to interruptible rate schedules, as recommended by Staff, is appropriate for this filing because it balances deliverability requirements for these customers with the practical use of the Company's system. That said, the Company acknowledges that refinement of LRIC study methodologies over time is possible either through peer review of best practices, analysis through the Company's Integrated Resource Planning ("IRP") process, or through actual observation of demand response events.

3. Service line allocation

Q. How did the Company allocate service lines in its LRIC study?

A. I created two allocators for service lines, which I labeled *Line-1* and *Line-2*. I calculated *Line-1* based on the average services cost per foot and the average footage installed derived using eight years of historical accounting data of Oregon services job orders (2015 – 2022) for customer service installations by market segment, inflated to account for costs through the Test Year.[31] Due to the small job sample size for the Commercial and Industrial schedules in the RS 31 and RS 32 rate classes, I used historical data to calculate a weighted median cost per foot.[32] Using a GIS data query for services connection footage by rate schedule historically, I estimated services cost by customer per rate schedule by multiplying the median footage by median cost per foot.[33] I then allocated these costs by applying an "investment carrying charge" to calculate the marginal, not actual, cost.[34] For *Line-1*, I only applied this methodology to RS 2 Residential, RS 3 General Commercial, and RS 27 Dry-Out. Using the indicated marginal cost for these rate schedules, I weighted each schedule's contribution to the overall cost for those schedules and converted it into the *Line-1* allocation factor.

[31] NW Natural/1800, Wyman/47.

[32] NW Natural/1800, Wyman/46-47.

[33] NW Natural/1800, Wyman/47.

[34] NW Natural/1800, Wyman/49. The carrying charge includes cost of capital (debt and equity), taxes, and depreciation to calculate the carrying percentage assigned to each category of investment.

I calculated the *Line-2* allocator based on the replacement service line cost by multiplying the historical installation cost (inflated to the Test Year) by the number of customers for all schedules in RS 31 and RS 32 rate classes.

Q. What was AWEC's feedback on this allocation methodology?

A. AWEC argues that the *Line-1* and *Line-2* allocators allocate service line costs to the RS 31 and RS 32 rate classes differently compared to all other rate schedules. Whereas *Line-1* uses a marginal approach, *Line-2* is based on replacement costs and this difference in approach results in more costs being assigned to the RS 31 and RS 32 rate classes than is necessary.[35] AWEC recommends that all rate schedules be allocated service line costs in a uniform manner based on the *Line-1* methodology.[36]

Q. What is the Company's response to AWEC's service line allocation recommendation?

A. The intention of applying a different allocation methodology to *Line-1* and *Line-2* was to group and weight rate schedules with similar service line costs on a per customer basis (e.g., the residential and general commercial schedules were grouped for *Line-1*, and the large commercial and industrial schedules *Line-2*). Upon review, I understand AWEC's concerns with applying an inconsistent methodology across this investment category. Therefore, I agree to adjust this methodology for the Company's next LRIC study filing.

[35] AWEC/100, Mullins/6-47.

[36] AWEC/100, Mullins/47.

Q. Please summarize the Company's overall response to AWEC's feedback on the LRIC study.

A. Based on AWEC's feedback, I agree to adjust the methodology for the allocators, *Dist-1* and *Line-1*. For *Dist-1*, I will apply an interruptible customer demand discount consistent with *Dist-5* and *Dist-6*. For *Line-1*, I will apply methodology consistently across all rate schedules (and therefore remove the *Line-2* allocator). I intend to implement these recommendations for the Company's next LRIC study filing.

Q. Why are you not updating your LRIC study in Reply Testimony?

A. AWEC calculated and presented modified results of my LRIC study in its Opening Testimony. The largest driver of the change in results is AWEC's application of a 100 percent interruptible customer demand discount, which I do not accept. Even with each of AWEC's modifications, there is very little directional movement in which schedules are under- and over-paying their overall cost of service. For the two rate schedules that showed directional movement from underpaying to overpaying (RS 3 Industrial and RS 32 Industrial Transportation Interruptible), I grouped them with like rate schedules for my rate spread proposal. I allocated a revenue requirement increment for RS 32 Industrial Transportation Interruptible commensurate with all other transportation rate schedules. For RS 3 Industrial, I allocated revenue requirement commensurate with other large commercial and industrial rate schedules that are not transportation service and that are not overpaying their cost of service such that I calculate a parity ratio of 1.75 at present rates. In short, an updated LRIC

study would not cause me to update my rate spread proposal as presented in my Direct Testimony.[37]

IV. RATE DESIGN

Q. What is the purpose of the rate design section in your Reply Testimony?

A. The Company proposed multiple rate design changes in Direct Testimony. In this section, I provide an overview of each of the proposals, summarize the response to each proposal from Parties' Opening Testimony, and present the Company's reply.

Q. Please summarize the Company's rate design proposals.

A. The Company's rate design proposals are as follows. The Company has proposed to:

1. Increase the monthly fixed charge for existing RS 2 Residential customers residing in single-family dwellings from $8.00 to $10.00 in order to collect more of its fixed costs on a per-customer, per-month basis;[38]
2. Maintain the current residential monthly fixed charge of $8.00 for existing RS 2 Residential customers residing in multi-family dwellings to reflect the comparatively lower cost of service for multi-family dwellings in relation to single-family dwellings;[39]
3. Bifurcate the residential class Decoupling Mechanism baseline into two cohorts to account for differences in the usage profiles of existing residential

[37] See NW Natural/1800, Wyman/84-85 for my rate spread proposal methodology.

[38] NW Natural/1800, Wyman/60-61.

[39] NW Natural/1800, Wyman/67-76.

premises compared to new residential premises that are connected to the system at the rate effective date of this proceeding;[40]

4. Set a monthly fixed charge of $26.25 for the new single-family residential premises that equitably recovers the cost to serve these customers at the proposed lower bifurcated Decoupling Mechanism baseline;[41] and
5. Set a monthly fixed charge of $24.25 for new multi-family residential premises which is based on the $26.25 new single-family residential premises monthly fixed charge, less the same $2.00 per month discount applied for existing RS 2 Residential customers residing in multi-family dwellings.[42]

Q. Why do the Company's proposals constitute sound rate design?

A. Together, the rate design proposals better align costs among four types of residential customers based on dwelling type and the date their premises was connected to the Company's system: Single-family and multi-family dwellings, and premises connected on or after the rate effective date of this proceeding ("New Premises") compared to premises connected prior to the rate effective date ("Existing Premises"). Two of the proposals (the lower monthly fixed charge for multi-family dwellings and the Decoupling Mechanism bifurcation) were raised by Staff in UG 435 and further examined by the Company. The purpose of the Company's rate design proposal as a whole is to mitigate residential intra-class subsidies between these four types of residential customers.

[40] NW Natural/1700, Walker/8-15.

[41] NW Natural/1800, Wyman/76-79.

[42] NW Natural/1800, Wyman/78.

Q. More specifically, why does the Company's proposal for the higher new premises monthly fixed charge constitute sound rate design?

A. The Company's proposal for the higher monthly fixed charge on New Premises maintains the same volumetric price signal for the residential rate class in order to promote a fair apportionment of revenue requirement across the Residential rate class, while avoiding different volumetric price signals on an intra-class level. The Company's proposal is responsive to the principle of fairness presented as "Attributes of a Sound Rate Structure" developed by James C. Bonbright ("Bonbright Principles"). The sixth principle seeks to avoid "arbitrariness and capriciousness" while attaining equity in three dimensions: "(1) Horizonal (i.e., equals treated equally); (2) vertical (i.e., unequals treated unequally); and (3) anonymous (i.e., no ratepayer's demands can be diverted away uneconomically from an incumbent by a potential entrant)."[43] The Company's proposal avoids arbitrariness in the volumetric price signal on an intra-class basis while maintaining equity between premises of different vintages (existing vs new) while also apportioning rates that recognize differing costs of service across premises types (single-family vs multi-family) (i.e., four residential sub-classes).

Q. Please summarize the Company's rate design proposal for each of the four residential sub-classes.

A. In Table 1 below, I present the Company's rate design proposal for each of the four residential sub-classes. I present the proposed monthly fixed charge, as

[43] See: Bonbright, James C., Albert L. Danielsen, David R. Kamerschen. *Principles of Public Utility Rates* (Second Edition, 1988). Public Utilities Reports, pages 383-384.

well as two volumetric charges: the base margin rate and the total billing rate which includes all temporaries plus the commodity cost. As shown in Table 1, the volumetric price signal remains the same across all residential sub-classes. Therefore, every residential customer pays the same for an incremental therm so that the Company's fixed costs are not collected through varying volumetric rates throughout the class. The higher monthly fixed charge for the New Premises, as I explain in my testimony below, mitigates intra-class subsidies between the Existing Premises and New Premises residential customer vintages.

Table 1
Residential Class Rate Design Proposal,
Fixed Charge and Volumetric Rates,
by Residential Customer Type[44]

			Volumetric Based Charge	
Residential Vintage	**Dwelling Type**	**Monthly Fixed Charge**	**Base Margin Rate**	**Total Billing Rate**
Existing Premises	Single-Family	$ 10.00	$ 0.90649	$ 1.51976
Existing Premises	Multi-Family	$ 8.00	$ 0.90649	$ 1.51976
New Premises	Single-Family	$ 26.25	$ 0.90649	$ 1.51976
New Premises	Multi-Family	$ 24.25	$ 0.90649	$ 1.51976

[44] For the Company's rate design model, please refer to the submitted workpaper, "UG 490 - Exh. 1803 and 1804 - WP1 - Rate Spread and Rate Allocation Model."

A. Residential single-family dwelling monthly fixed charge

1. Overview of Company's Proposed Modifications to Fixed Charge for Existing Premises Single-Family RS 2 Residential Customers

Q. What is the Company's proposal for its monthly fixed charge for RS 2 Residential customers residing in single-family dwellings?

A. The Company proposed to increase the fixed monthly charge for Existing Premises RS 2 Residential customers residing in single-family dwellings from $8.00 to $10.00. This proposal applies to all single-family residential premises connected to the Company's system prior to November 1, 2024.

Q. What is a single-family residential premises?

A. A single-family residential premises is a detached residential dwelling with a service line and meter.

Q. Why did the Company make this proposal?

A. The LRIC study indicated the fixed monthly charge for the Residential class at the proposed rates in this proceeding should be set at an estimated $37.06 per customer per month. At the current rate of $8.00, the Company would only collect about one-fifth of its fixed costs through the fixed charge component of its Residential rate, relying on collection of the remaining four-fifths through the volumetric rate component that produces revenues that vary seasonally and year-to-year based on weather.[45] The Company's proposal of $10.00 balances the need to increase the fixed charge with principles of gradualism, and results in

[45] NW Natural/1800, Wyman/60.

a more reasonable level of fixed cost recovery that is not contingent on weather. Under this proposal, the Company recovers 27.0 percent of its total fixed costs through the fixed charge. As I demonstrated in my Direct Testimony, the Company's existing monthly RS 2 Residential fixed charge ranks near the bottom of all peer utility residential monthly fixed charges—and would continue to rank near the bottom even with the increase to $10.00.[46]

2. Reply to Parties' Testimony Regarding Modifications to Fixed Charge for Existing Premises Single-Family RS-2 Residential Customers

Q. Did the Parties provide feedback on this proposal?

A. Yes. Staff provided Opening Testimony regarding the modification to increase the fixed charge for Existing Premises single-family customers. CUB and the Coalition did not directly address the Company's proposal in their Opening Testimonies.

Q. What was Staff's feedback?

A. Staff indicated both that it is "supportive" of this proposal "for the time being"[47] and that it "takes no issue with the increase to the [single-family residential] basic charge at this time."[48] Staff notes, however, that affordability concerns "gives reason to consider this proposed increase directly through the lens of customer impacts," and that it may update its position following the Energy Justice Issues

[46] NW Natural/1800, Wyman/75.

[47] Staff/300, Scala/18.

[48] Staff/1800, Shierman/18.

Public Workshop that was held April 25, 2024, as well as based on other Parties' testimony.[49]

Q. Did the Company consider affordability when making this proposal?

A. Yes, affordability for Existing Premises customers was an influence in the Company's decision to graduate the increase in the fixed charge to $10.00, instead of the $37.06 that would otherwise have been the result of the LRIC study. The Company notes, however, that although the higher monthly fixed charge increases the minimum bill amount, it results in a downward pressure on volumetric rates and therefore lower winter bills when all energy bills are higher. I explain this in greater detail later in my testimony.

3. Overview of Company's Proposed Modifications to Fixed Charge for Existing Premises Multi-Family RS 2 Residential Customers

Q. What is the Company's proposal for its monthly fixed charge for Existing Premises RS 2 Residential customers residing in multi-family dwellings?

A. The Company proposed to retain the monthly fixed charge for RS 2 Residential customers residing in multi-family dwellings at $8.00, which is $2.00 lower than the proposed $10.00 single-family residential monthly fixed charge. This proposal applies to all multi-family residential premises connected to the Company's system prior to November 1, 2024.[50]

[49] *Id*., Shierman/18-19.

[50] NW Natural/1800, Wyman/63.

Q. What is a multi-family residential premises?

A. For the purposes of this proposal, multi-family residential premises are dwelling units of two or more attached units including duplexes, apartments, condos, or townhomes that are individually metered on RS 2 Residential. For reference, there are other types of multi-family dwellings on the Company's system that can fall under different rate schedules depending upon the circumstances of the dwelling and service type, which are not included in this proposal:

- Schedule 3 Basic Firm Sales Service Non-Residential (RS 3 Commercial), which includes residents of a multi-family building with natural gas service that is master metered under a commercial rate schedule and, therefore, are not directly charged by the utility and are not utility customers; and
- Schedule 4 Residential Multi-Family Service (RS 4 Multi-Family) for customers that reside in a particular type of multi-family building.
- Additionally, NW Natural also serves master-metered multi-family buildings where a single meter serves the entire building. These multi-family buildings may have several residences served by the single meter, but the customer account and billing are associated with a property management company or landlord. These customers are typically serviced on RS 3 Commercial.[51]

Q. Why did the Company make this proposal?

A. In UG 435 Opening Testimony, Staff indicated interest "in exploring whether or not the Company should separate pricing for multi-family residential customers"

[51] NW Natural/1800, Wyman/68-69.

based on distinctions that could make the fixed costs of serving multi-family premises lower relative to single-family premises.[52] These distinctions are based largely on economic and spatial efficiencies associated with serving customers that are generally clustered, and are located in higher density urban areas within the Company's service territory. Hypothetically, such efficiencies may be due to lower marginal distribution costs on a per multi-family premises basis as it requires fewer average feet of main, for instance, to serve each premises relative to single-family premises due to spatial clustering.[53]

In response to Staff's interest, the Company hosted a workshop and presented results relating to the difference in fixed cost for serving multi-family residential premises compared to single-family residential premises. The results indicated that fixed cost rate component for multi-family residential premises is about 21.2 percent lower compared to single-family residential premises, and I proposed a 20.0 percent reduction as a practical matter to maintain a rounded fixed charge amount for both premises types. I made this proposal in response to the spatial and economic fixed cost efficiencies suggested by the results of this analysis, to be consistent with responses of peer utilities to similar analyses, and because the likelihood that customers residing in multi-family premises live in low

[52] In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision, Docket No. UG 435, Staff/1300, Scala/48, lines 18-19 (April 22, 2022).

[53] NW Natural/1800, Wyman/71.

(or lower) income households is slightly higher than that of customers residing in single-family premises.[54]

4. Reply to Parties' Testimony Regarding Proposed Modifications to Fixed Charge for Existing Premises Multi-Family RS 2 Residential Customers

Q. Did the Parties provide feedback on this proposal?

A. Yes. Staff and CUB provided feedback on this proposal.

Q. What was Staff's feedback?

A. Staff is appreciative of the Company for "carrying out the thorough analysis following our recommendation in UG 435"[55] and is supportive of the proposal.[56] Staff notes that although the results of the analysis can be sensitive to assumptions, "Staff is convinced that the Company's modeling is adequate to justify a bifurcated basic charge even if one were to view it through a cost causation lens."[57] Staff expects that the Company's proposal will have positive equity impacts owing to the fact that low-income customers are more likely to live in multi-family dwellings.[58]

[54] NW Natural/1800, Wyman/71-75.

[55] Staff/1800, Shierman/18.

[56] Staff/300, Scala/18.

[57] Staff/1800, Shierman/18.

[58] *Id*.

Q. What was CUB's feedback?

A. CUB indicates its support for the Company's proposal but does not provide any specific feedback.[59]

Q, Does the Company have anything further to add regarding this proposal?

A. The Company appreciates Parties' engagement regarding its proposal to bifurcate the single-family and multi-family monthly fixed charges for Existing Premises and has no further changes to this proposal.

B. Decoupling Mechanism bifurcation

1. Overview of Company's Decoupling Mechanism Bifurcation Proposal

Q. What is the Company's Decoupling Mechanism bifurcation proposal?

A. The Company has proposed to bifurcate its residential Decoupling Mechanism baseline to reflect two cohorts of residential customers based on the premises where they reside:

1. Existing residential premises ("Existing Premises") that either currently take service or will take service on RS 2 Residential prior to November 1, 2024. Customers residing at these premises have an expected average weather normalized UPC of 660.2 therms.
2. New residential premises ("New Premises") that do not currently take any service on the Company's system and are connected on or after November 1, 2024. Premises in this cohort can be connected to the system either as newly constructed homes (by way of greenfield or infill development), or by

[59] CUB/200, Garrett/10.

opting for natural gas conversion for an already existing residential dwelling. There are no customers in this cohort currently. Future customers that will reside at these premises have a forecasted expected average weather normalized UPC of 449.4 therms.

Q. Does the Company discuss its bifurcated Decoupling Mechanism proposal and Parties' response elsewhere in Reply Testimony?

A. Yes. Company witness Kyle T. Walker summarizes the Company's bifurcated Decoupling Mechanism proposal as described in the Company's Direct Testimony and summarizes and responds to Parties' positions in the Company's Reply Testimony at NW Natural/3800, Walker.

Q. How does the bifurcated Decoupling Mechanism proposal impact rate design?

A. In tandem with the Company's proposed New Premises monthly fixed charge proposal, the bifurcated Decoupling Mechanism proposal fundamentally alters how the Company collects its cost of service when usage varies from normal for the New Premises cohort. Staff has argued, and the Company agreed, that customers residing at New Premises dwellings will have lower baseline weather normalized usage due to new residential premises being associated with more energy efficient homes (e.g., tighter building envelop, more up-to-date building standards, etc.) and a mix of higher efficiency / lower use appliances compared to customers residing at Existing Premises dwellings. Under the Company's existing Decoupling Mechanism, all residential customers are decoupled to a

single baseline, which will overstate residential usage between rate case proceedings for New Premises.

This result is problematic, as it drives a larger regulatory asset for the decoupling deferral, which in turn impacts higher use (Existing Premises cohort) customers more than lower use (New Premises cohort) customers because the deferral gets recovered through the volumetric rate. Thus, without intervention, the New Premises cohort will not pay its full cost of service when usage varies from normal, and the Existing Premises cohort will subsidize the New Premises cohort.

The purpose of the bifurcated Decoupling Mechanism proposal is to mitigate this issue by assigning an expected weather normalized usage that is about 31.9 percent lower than the Existing Premises cohort. This bifurcation should minimize the decoupling deferral, reducing the intra-class subsidies that occur through the current Decoupling Mechanism. It is the Company's understanding that this is consistent with Staff's view on the purpose and expected outcome of this proposal.[60]

[60] *See, e.g.* Docket No. UG 435, Staff/1300, Scala/19, 25 ("Staff is concerned that the difference in usage between new customers coming on NW Natural's system and existing customers is too large to ignore. Failure to distinguish between new and established customer usage may overstate the impact of lower average use per customer under certain conditions" * * * * "Staff finds it is appropriate for the Company to distinguish between new and established customers in decoupling calculations.")

Q. How does the bifurcated Decoupling Mechanism proposal in tandem with the introduction of a higher monthly fixed charge equitably assign costs to each cohort on an intra-class basis?

A. The bifurcated Decoupling Mechanism proposal in tandem with the introduction of a higher monthly fixed charge equitably assigns the costs to both cohorts on an intra-class basis using a two-step process:

1. Creates a decoupling baseline based on the expected annual weather normalized forecasted UPC for each cohort. These values, which are presented in the Company's Direct Testimony, are: 660.2 therms for Existing Premises customers and 449.4 therms for New Premises customers.
2. Introduces a higher monthly fixed charge of $26.25 for the New Premises single-family residential and $24.25 for the New Premises multi-family residential cohorts to account for the lower decoupled baseline. These fixed charges are based on the shortfall of decoupled revenues that would be collected from these cohorts compared to the Existing Premises cohorts introduced by Step 1. Step 2, as I explain below, ensures that the New Premises cohorts cover their cost to serve notwithstanding a baseline that is set 31.9 percent (210.8 therms) lower to avoid the issue of intra-class subsidization with the Existing Premises cohorts.

2. Reply to Parties' Testimony Regarding the Company's Decoupling Mechanism Bifurcation Proposal

Q. What is Staff's approach for this proposal?

A. Staff believes that the issue of intra-class subsidization between New Premises and Existing Premises customers can be mitigated through the Decoupling Mechanism (Step 1) and further rate design (Step 2) is not necessary. Staff states: "[NW Natural] is proposing to differentiate between existing and new customers in its decoupling mechanism calculation, however Staff sees the rationale for this proposal as sufficiently different from the rationale for the new premises basic charge."[61]

Q. What is your response?

A. I disagree. I argue that the two steps I described above are needed to avoid intra-class subsidization between New Premises and Existing Premises customers post-bifurcation.

Q. Why is the two-step approach required to avoid intra-class subsidization?

A. As I noted earlier, the bifurcated Decoupling Mechanism proposal fundamentally alters how the Company collects its cost of service when usage varies from normal for the New Premises cohorts. With no change to rate design, the New Premises cohort baselines of 449.4 therms result in the Company recovering about $191 less per New Premises customer in base margin annually compared to an Existing Premises customer at the 660.2 therm baseline at the rates

[61] Staff/1800, Shierman/21.

proposed in this proceeding.[62] The cost to serve a customer in each cohort is similar, however: New and Existing Premises are generally served by the same type (size and operating pressure) and length of service line, similar type of meter and regulator, and have the same or similar customer service, meter reading, billing, and administrative costs. In the absence of any change to the billing determinants (either the monthly fixed charge or the volumetric rate) for the New Premises cohorts, the Company would under-recover the cost of service associated with New Premises customers and over-recover the cost of service associated with Existing Premises customers. This is why simply establishing the two baselines for decoupling (Step 1) alone does not mitigate the issue of intra-class subsidization, and why a rate design modification (Step 2) is necessary.

Q. What is the consequence of bifurcating the Decoupling Mechanism (only taking Step 1) but not making a rate design modification (omitting Step 2)?

A. Without a rate design modification for the New Premises cohort, the Company's base margin volumetric rate would be higher relative to the Company's proposal. The higher volumetric rate would impact higher users the most, including those users who are least able to respond in the short-run to higher price signals with energy efficiency measures such as new appliance purchases and home weatherization. The higher volumetric rate places a higher impact on the higher-use cohort (Existing Premises) which, as I discuss later, has a higher proportion

[62] The proposed base margin is $0.90649. The $191 value is derived by multiplying this amount by the difference in baseline therms between the two cohorts (210.8 therms). $0.90649*210.8 = $191.11.

of lower-income customers compared to the New Premises cohort. With no change to the New Premises rate design, the Company would under-collect about $612 thousand from New Premises cohort customers in the Test Year, which will be collected through the volumetric base margin rate from all (Existing Premises and New Premises) customers with higher users paying more (i.e., intra-class subsidization).

Q. Does this impact any other rate schedules?

A. No. This is an issue of intra-class residential rate design, and therefore does not result in any costs being placed on the volumetric rate of any other rate schedules.

C. New Premises Customer Charge

1. Overview of Company's Proposed New Premises Customer Charge

Q. What New Premises monthly fixed charge rate design has the Company proposed?

A. The Company proposed a higher monthly fixed charge of $26.25 for New Premises single-family cohort customers. This higher monthly fixed charge is set to reflect the difference in the UPC for New Premises customers compared to Existing Premises customers. In other words, the difference in proposed monthly fixed charge between the groups -- $16.25 – roughly covers the cost-of-service

recovery shortfall associated with the 210.8 therm lower New Premises annual weather normalized usage.[63]

The New Premises monthly fixed charge will ensure that new residential customers as a group are providing equivalent contributions for their cost of service as Existing Premises customers. For this reason, and the reasons I discuss below, the Company's proposal promotes fairness and equity in residential rate design.

Q. Are Parties supportive of the Company's rate design modification?

A. Staff, CUB, and the Coalition are not supportive of the Company's New Premises monthly fixed charge rate design modification,[64] as I discuss below.[65] However, the Parties' position on this issue would serve to retain the intra-class subsidy for the benefit of the New Premises cohorts to the detriment of the Existing Premises cohorts.

Q. What is the New Premises monthly fixed charge proposal?

A. The Company proposed to include a higher monthly fixed charge for New Premises customers ("New Premises Customer Charge") added to the system on or after the effective date of rates for this proceeding (November 1, 2024). The Company plans to charge these New Premises customers (i.e., new residential premises added to the system) $26.25 per month. This fixed charge is $16.25

[63] The higher monthly fixed charge amount recovers $195.00 annually ($16.25*12). This is slightly higher than the $191.11 due to rounding of billing determinants.

[64] Staff/900, Dlouhy/44; CUB/200, Garrett/8-10; Coalition/100, Cebulko/6.

[65] Staff/1900, Stevens/20-24.

more per month than the proposed monthly fixed charge for Existing Premises customers. Due to the lower annual average weather normalized UPC associated with New Premises customers relative to Existing Premises customers, the higher fixed charge allows the Company to maintain the same variable price signal for all residential customers on an intra-class level. This higher fixed-to-variable rate design flattens the anticipated delivery margin revenues from New Premises customers while enabling the Company to collect its full cost of service, thereby avoiding an intra-class subsidy between Existing Premises and New Premises residential customers.

Q. Please describe a New Premises customer.

A. A New Premises customer is a customer who purchases, rents, or otherwise occupies a residential dwelling that is connected to the Company's system on or after November 1, 2024, and opens an account at or transfers an account to that premises. A New Premises is a premises that is connected to the system via line extension and can be either new construction, infill development, or a natural gas conversion.

It is important to understand this definition. A customer that is new to NW Natural (i.e., has moved into the Company's service territory from elsewhere) and who moves into a premises that was connected prior to November 1, 2024 (an Existing Premises) is not a New Premises customer and would therefore be subject to the standard RS 2 Residential monthly fixed charge of $10.00 proposed in this proceeding. Likewise, if a customer were to move from a New Premises to an Existing Premises, they would then be subject to the $10.00

monthly fixed charge. The New Premises Customer Charge, therefore, is associated with the premises, not the customer account.

Q. Will any of the Company's existing customers be charged the New Premises Customer Charge at the rate effective date of this proceeding?

A. No. There are no existing customers that will be charged the New Premises Customer Charge beginning November 1, 2024. Only future customers and existing customers who purchase, rent, or otherwise occupy a newly constructed or converted dwelling connected to the system on or after November 1, 2024 will be subject to this charge.

Q. Has the Company analyzed its data to better understand common characteristics of New Premises customers?

A. Yes. While the Company does not have household income or other demographic data on an individual customer basis, we can infer some common characteristics about New Premises customers connected to the Company's system from 2018 through 2023.[66] New Premises connections are:

- Largely single-family dwellings: 92.7 percent during this period were identified as single-family dwellings, and 7.3 percent were multi-family.
- Mostly new construction: 78.4 percent during this period were new construction greenfield or infill development, and 21.6 percent were natural gas conversions at previously constructed dwellings.

[66] These data, except where noted, were sourced using information presented in Exhibits Coalition/106 and Coalition/107.

- Are less likely to request or be enrolled in the bill discount program: 3.5 percent of customers residing at premises connected to the system during this period were enrolled in the bill discount program as of January 2024, compared to 7.2 percent of all Oregon residential customers. Of just single-family residential premises connected from 2018 through 2023, 3.3 percent enrolled, while 5.6 percent of multi-family premises enrolled.
- Are more likely to reside in a Census Tract with a median household income higher than the median household income for Oregon: An average Census Tract median household income of $97,576 compared to a median household income of $75,657 for Oregon (both figures in 2022 dollars).[67]

In summary, New Premises cohort customers who purchase, rent, or otherwise occupy a residential dwelling that is connected to the Company's system on or after November 1, 2024, will have a higher median household income and are more likely to live in newly constructed single-family dwellings compared to customers in the Existing Premises cohort. Most (56.7 percent) of these customers are located in the Portland metro area[68] where the average new construction detached single-family dwelling is listed for $683,602 a new construction attached dwelling is listed for $411,600 as of May 2024.[69] New Premises cohort customers, therefore, are less likely to be lower-income

[67] US Census Bureau. 2022 American Community Survey 1-Year Estimates. *See*: https://data.census.gov/profile/Oregon?g=040XX00US41.

[68] Defined here as located in Multnomah, Washington, or Clackamas counties.

[69] Zonda Market Report for Portland-Vancouver-Hillsboro, OR-WA. May 6, 2024.

compared to Existing Premises customers, and are less likely to enroll in or be eligible for bill assistance programs.

Q. Please summarize how you calculated the New Premises Customer Charge.

A. I apportioned the Test Year Residential class customer count and volumes among the four residential sub-groups: existing single-family, existing multi-family, new premises single-family, and new premises multi-family. Using the class-wide incremental revenue requirement determined through the Company's rate spread proposal, I solved for new premises single- and multi-family fixed monthly charges that would maintain the same volumetric rate across all sub-classes. This calculation results in roughly the same normalized expected revenues per customer between existing and new premises single-family residential customers (as well as the same between existing and new premises multi-family residential customers).

Q. What is the effect of the higher New Premises Customer Charge on the apportionment of revenue requirement to each sub-class given you have proposed to maintain the same volumetric charge?

A. The Company's residential rate design proposal apportions the proposed residential revenue requirement across the four sub-classes. The two Existing Premises sub-classes have expected usage at the 660.2 therm decoupling baseline; the two New Premises sub-classes have expected usage at the 449.4 therm baseline. With the higher New Premises Customer Charge, more of the overall residential revenue requirement is apportioned to new premises than would otherwise be apportioned with a lower monthly fixed charge. The effect on

the residential class of the higher New Premises Customer Charge is zero-sum, reducing how many dollars are allocated for the (singular) volumetric charge. As I discuss in further detail below, the effect of not using the higher fixed monthly charge as proposed would result in an increase in the volumetric allocation for all sub-classes of about $612 thousand assuming the Test Year average new premises customer additions.[70] Using the Test Year end of period customer additions, this value is roughly $1.2 million on an annualized basis, indicating how quickly this value increases as customers are connected to the system. This volumetric allocation would impact the higher use Existing Premises cohort to a greater extent compared to the lower use New Premises cohort.

Q. Did you provide this allocation to Parties with your Direct Testimony?

A. Yes. I provided this allocation in the submitted workpaper, "UG 490 – Exh. 1803 and 1804 – WP1 – Rate Spread and Rate Allocation Model" in a tab labeled "UG 490 Rate Design Proposal."

Q. You mention that the New Premises Customer Charge calculation is based on the overall residential revenue requirement. Does this mean that the actual New Premises Customer Charge will be calculated based on the final authorized revenue requirement from this proceeding?

A. Yes. This is a point that I did not make clear in my Direct Testimony. The Company's higher New Premises Customer Charge for both single- and multi-

[70] Please refer to the submitted workpaper, "UG 490 – Exh. 1803 and 1804 – WP1 – Rate Spread and Rate Allocation Model" tab "UG 490 Rate Design Proposal." The value $612,300 is calculated by multiplying the average Test Year customer additions for the New Premises single-family and multi-family sub-classes by the fixed monthly charge delta from Existing Premises ($16,25) by 12 months.

family residential premises is based on the initially requested $154.9 million revenue requirement, and importantly, is intended to utilize nearly the same volumetric rate as Existing Premises customers so that all residential customers have similar price signals for usage. To the extent the revenue requirement decreases in this proceeding, the Company will proportionately lower the monthly fixed charge for New Premises customers based on that final amount, in accordance with the rate design principles I have explained for this charge.

2. Reply to Parties' Testimony Regarding New Premises Customer Charge

Q. Did Parties provide feedback regarding the New Premises Customer Charge?

A. Yes. Staff, CUB, and the Coalition provided feedback on the Company's proposed New Premises Customer charge.

Q. What was Parties' response to the proposed New Premises Customer Charge?

A. Staff, CUB, and the Coalition rejected the New Premises Customer Charge proposal.

Q. What is CUB's concern with the New Premises Customer Charge?

A. CUB argues that under the Company's proposal, a New Premises customer "will pay about 51 percent more than an existing customer for using the same amount

of gas."[71] CUB is "concerned that charging 'new premise' customers 51 percent more than ~180,000 existing customers with the same usage is discriminatory."[72]

Q. How do you respond to CUB's assertion that a New Premises customer will be charged 51 percent more than an Existing Premises customer?

A. I take issue with the entire premise of CUB's analysis. First, however, I point out that CUB's calculated result is incorrect based on a math error. In CUB/203, Garrett/2, CUB calculates an "Annual Rate ($)" and a "Annual Rate / Therm ($/therm)" for New Premises and Existing Premises customers both assuming an annual usage of 449 therms and the proposed total residential base rate of $0.90649 from this proceeding. CUB calculates an Annual Rate value of $527.01 and $722.01 for Existing Premises and New Premises, respectively. CUB's analysis calculates an Existing Customer Annual Rate per Therm of $1.17 by dividing $527.01 by 449. CUB's analysis inexplicably shows a New Customer Annual Rate per Therm of $1.77 even though using the same methodology to divide $722.01 by 449 results in a New Premises Customer Annual Rate per Therm value of $1.61.[73]

CUB's result, therefore, should have indicated the New Premises customer is paying 37.0 percent more than the Existing Premises customer, not 51 percent. Notwithstanding the math error, it is unclear why CUB takes the

[71] CUB/200, Garrett/8.

[72] *Id*., Garrett/9.

[73] It appears that CUB may have inadvertently used an annual UPC value of 531.16 instead of 449 for this calculation even though this figure does not appear at CUB/203, Garrett/2.

additional step of converting the monthly fixed charge to a per therm amount rather than present the result simply as a cost differential given the cost is what the customer experiences. Furthermore, the premise of the analysis itself is not sound. It would have been more appropriate to use the residential total billing rate proposed in this proceeding of $1.51976 per therm to calculate the cost differential, not the total base rate. The total billing rate reflects the goal of CUB's analysis to show how much one cohort is paying more or less than the other at a given usage level.[74] If CUB had performed this analysis correctly, it would indicate the New Premises cohort paying 24.3 percent more than the Existing Premises cohort at 449.4 therms annually. This assumes the usage of a typical New Premises customer compared to an Existing Premises customer using 31.9 percent less natural gas than is typical for an average customer in that cohort on a weather normalized basis.

Finally, I will point out that CUB's analysis does not even begin to address the question of what the Company's cost to serve an Existing Premises and a New Premises is and what billing determinants are required to achieve rate equity between the two cohorts.

[74] CUB/203, Garrett/2 cites UG 490 CUB DR 9 Attachment 1 as a source for this calculation. In reviewing the data request, I notice that CUB requested projected use-per-therm rates inclusive of the monthly customer charge. The Company responded with a calculation based on the proposed UG 490 Total Base (Margin) Rate. The calculation of an all-inclusive per therm rate should have included temporary rates and the commodity charge, which would have been the total proposed billing rate of $1.51976.

Q. Can you give an example showing why CUB's usage of an annual rate per therm is not a sound methodology?

A. Yes. Consider Customer A that uses 450 therms and Customer B that uses 650 therms. Both customers are billed a $10 monthly fixed rate and a volumetric rate of $1.50 per therm. Customer A would pay $795 annually and Customer B would pay $1,095 annually. Using CUB's methodology, Customer A will pay only 4.9 percent more than Customer B for using the same amount of gas ($1.77 per therm for Customer A compared to $1.68 per therm for Customer B). This ignores the fact that Customer B is paying 37.7 percent more annually ($795 for Customer A compared to $1,095 for Customer B) due only to the fact that Customer B has used more gas. This conclusion also ignores the question of whether Customer A is covering its cost to serve at its usage level given these billing determinants, and whether Customer B is paying too much or just enough.

Q. Why does the Company's proposal result in a cost differential when comparing a *typical* New Premises customer using 449.4 therms against an *atypical* Existing Premises customer using the same amount of therms?

A. As I explained earlier in my testimony, Staff argued in UG 435, and the Company agreed, that there is a fundamental difference between Existing Premises and New Premises usage such that a change – the bifurcation of Decoupling Mechanism – is warranted.[75] This change alters the ratemaking of the residential class, and as I explained earlier, necessitates a rate design modification to avoid

[75] *See, e.g.* Docket No. UG 435, Staff/1300, Scala/19, 25.

intra-class subsidization that more heavily impacts the higher use Existing Premises cohort. It is standard ratemaking practice to calculate billing determinants (the monthly fixed charge and volumetric rates) using the annual weather normalized UPC (i.e., the typical use for an average customer) for each set of customers grouped by common characteristics. Therefore, the ratemaking for the *typical* lower-use New Premises customer is based on 449.4 therms and the *typical* higher-use Existing Premises customer is based on 660.2 therms annually. It would not be sound ratemaking (nor would it be fair or just to customers) to set rates based on the bottom one-third of users just as it would not make sense to set rates based on the top one-third (or one-tenth, for that matter) of users and charge those rates to every customer in the class.[76]

Q. Does the Company have any rates that have the same cost per unit of natural gas consumed compared to any other rate?

A. No, rates are developed based on many factors including cost to serve as indicated by the LRIC study, and number of customers and load profile of the class, temporaries and adjustments that are only applied to specific rate schedules, as well as the outcome of rate case settlement. Total cost per therm

[76] From a practical standpoint, "the attempt to estimate what part of the total cost of operating a utility business constitutes the cost of service each individual ratepayer or class of ratepayers would involve a hopelessly elaborate and expensive type of cost analysis. For this reason alone, the most that can be hoped for is the development of techniques of cost allocation that reflect only the major, more stable, and more predictable cost relationships." See: Bonbright, James C., Albert L. Danielsen, David R. Kamerschen. *Principles of Public Utility Rates* (Second Edition, 1988). Public Utilities Reports, pages 391-392.

of gas consumed, therefore, is not a reasonable measure for comparing intra-class equity between rate schedules or rate classes.

Q. How do you respond to CUB's statement that the Company is charging new premises customers a higher rate for the same amount of gas is "discriminatory," and creates an "intra-class equity concern"?[77]

A. Again, I reject CUB's analysis that converts the fixed monthly charge to a unit of gas rather than using a simple cost comparison. Further, I have multiple issues with CUB's statement that the Company's New Premises Customer Charge is "discriminatory" and creates an "intra-class equity concern."

CUB implies that a non-discriminatory New Premises rate is equal to an Existing Premises rate at any therm amount (e.g., the cost per unit of gas consumed is the same or nearly the same). This is the rate structure that exists today and is the reason why the bifurcated Decoupling Mechanism was proposed in the first place in response to concerns about intra-class subsidization. The bifurcation recognizes that the two cohorts have different baselines of usage and that they should be treated differently in ratemaking. Given the two baselines, 449.4 therms and 660.2 therms, and assuming the same billing determinants are used for a customer at either baseline, CUB does not demonstrate why a *typical*

[77] CUB/200, Garrett/8.

New Premises customer should pay 28.5 percent less than a *typical* Existing Premises customer.[78]

Recall that CUB argued that the Company's proposal would result in New Premises customers paying (the incorrectly calculated) 51 percent more per therm than roughly 180,000 Existing Premises customers. On the other side of the coin, if the Company's New Premises monthly fixed charge proposal were to be rejected, roughly 434,000 Existing Premises customers (about 71.0 percent of all residential customers) will pay *more* than a typical New Premises customer on a total billing basis.[79] As I explained earlier in my testimony, New Premises customers are on average more likely to live in higher-income Census Tracts, are more likely to be owners of newly constructed single-family residences, and are less likely to be enrolled the Company's bill discount program compared to Existing Premises customers on average. Also, as I explained earlier, any shortfalls in the collection of cost of service from New Premises customers will be charged through the residential base volumetric rate which will impact higher use Existing Premises customers more. Therefore, CUB's recommended rejection of the Company's proposal does not address intra-class equity or energy equity concerns, nor does it address "attempts by this Commission to address energy burden."[80]

[78] The 28.5 percent figure is derived using the proposed $10.00 monthly fixed charge and the $1.51976 total volumetric billing rate for both cohorts, with a New Premises customer using 449.4 therms and an Existing Premises customer using 660.2 therms.

[79] I estimate this figure using the same data and methods as shown at CUB/203, Garrett/2.

[80] CUB/200, Garrett/10.

Q. What evidence do you have that New Premises customers would be underpaying their cost to serve at the 449.4 therm baseline given the same rates as Existing Premises customers, and thereby not addressing the issue of intra-class equity concerns?

A. In my Direct Testimony, I presented the results of my LRIC study which indicated that the residential class is underpaying its cost of service at current rates at an average weather normalized UPC of 660.2 therms. I reported a residential class parity ratio of 0.96 at present rates, where a ratio of 1.00 indicates rate parity, and a ratio above and below 1.00 indicates a rate schedule is overpaying and underpaying its LRIC study indicated cost of service, respectively. At an average weather normalized UPC of 449.4 therms, and assuming the same present rates, the revenue shortfall is exacerbated if the bifurcated Decoupling Mechanism proposal is adopted (e.g., revenues are only collected on 449.4 therms instead of 660.2 therms) causing the parity ratio to move further away from 1.00 (i.e., lower).

Q. CUB asserts that by discontinuing gas service, a New Premises customer could save $7,875 by avoiding the New Premises Customer Charge. How do you respond?

A. CUB testifies that over the course of the 25-year repayment period modeled in the Company's line extension allowance ("LEA") proposal, a "new customer could save $7,875 by discontinuing gas service."[81] CUB calculates that amount

[81] CUB/200, Garrett/11.

because the LEA will require repayment over a 25-year period, repayment will cost the New Premises customer approximately $7,875 and the customer can simply save that full amount by electing to forgo gas service.

CUB's analysis is not complete and either lacks important assumptions or does not make its assumptions clear. Given that CUB ties its analysis to the 25-year period for the LEA, I infer that CUB is attempting to compare costs on a New Premises dwelling that is newly constructed. At the outset, natural gas service to a residence is choice, and the option for customers to not pursue natural gas service is always available to them. However, if the New Premises buyer opts not to install a natural gas service line as CUB suggests, to quantify the opportunity cost CUB's analysis would need to offset the cost savings with the energy costs associated with an alternative scenario, such as a fully electric home. If, on the other hand, the natural gas service line and appliances are pre-installed prior to purchase, the buyer would have to tear them out and "terminate NW Natural service within 25 years,"[82] replacing them with non-gas equivalents (such as an electric fireplace or cooktop). In this scenario, CUB's analysis would not only need to account for the energy cost differential, but the cost of the replacement appliances. This exercise would require at a minimum forecasting 25 years of both gas and electric energy costs on an assumed mix of appliance types, which CUB does not attempt to do.

[82] CUB/200, Garrett/18.

Given these limitations and unaddressed assumptions, it is likely that the cost savings (if there were to be any at all) would be lower than CUB's stated value of $7,875.

Q. CUB also states: "The Company's LEA economic justification rests upon the following assumption: even though 'new premise' customers will use distinctly less gas, and quite possibly be less reliant upon NW Natural's service, 100% of them will be willing to pay ~50% more per therm than existing customers."[83] How do you respond in the context of rate design?

A. Again, CUB uses the incorrect and misleading 51 percent figure I discussed earlier. The fact is, under the Company's proposal, a typical New Premises customer using 449.4 therms will pay 11.2 percent *less* annually on a total billing basis compared to a typical Existing Premises customer using 660.2 therms. On a margin revenue basis, the amount collected is nearly the same.[84] The Company addresses CUB's cost competitiveness arguments with regards to its LEA proposal in NW Natural/4000, Therrien.

Q. How does the monthly total billing cost and margin revenues of a typical New Premises customer compare to that of a typical Existing Premises under the Company's proposed rate design?

A. Chart 1 below compares the total billing cost of a typical New Premises customer compared to a typical Existing Premises customer. Due to the higher New

[83] CUB/200, Garrett/18.

[84] There is a one-half of one percent difference due to rounding of the billing determinant values.

Premises Customer Charge and lower usage associated with this cohort, bills are roughly 19 percent ($29.72) lower in the winter months but 17 percent higher ($6.04) in the summer months compared to the Existing Premises cohort. Again, on an annualized basis, the total cost is 11.2 percent lower for the New Premises cohort.

Chart 1

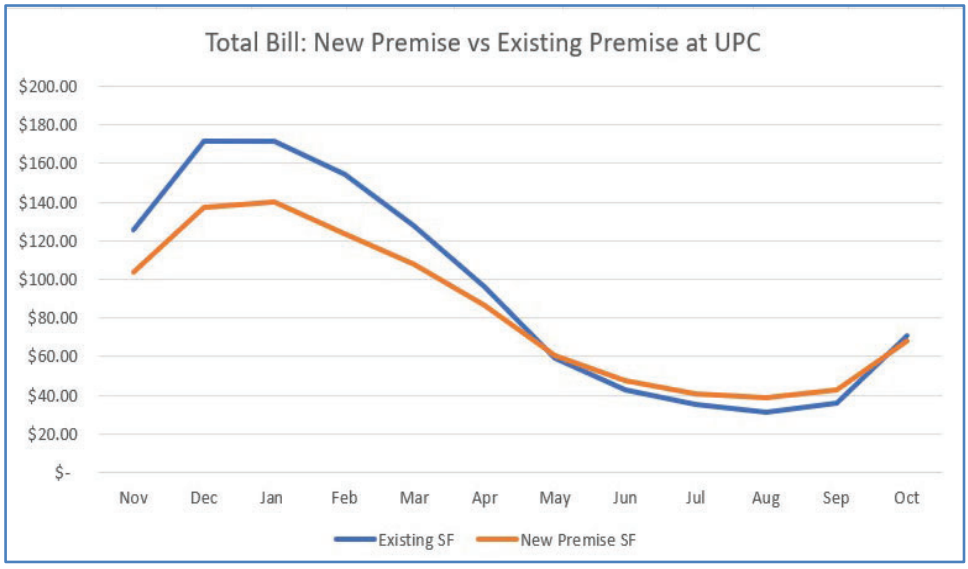


Chart 2 below shows the margin revenues on a per month basis. This chart indicates that the Company is recovering nearly the same cost to serve between both cohorts on an annualized basis. Without the proposed rate design, cost recovery would not be equal between the cohorts on an annualized basis.

Chart 2

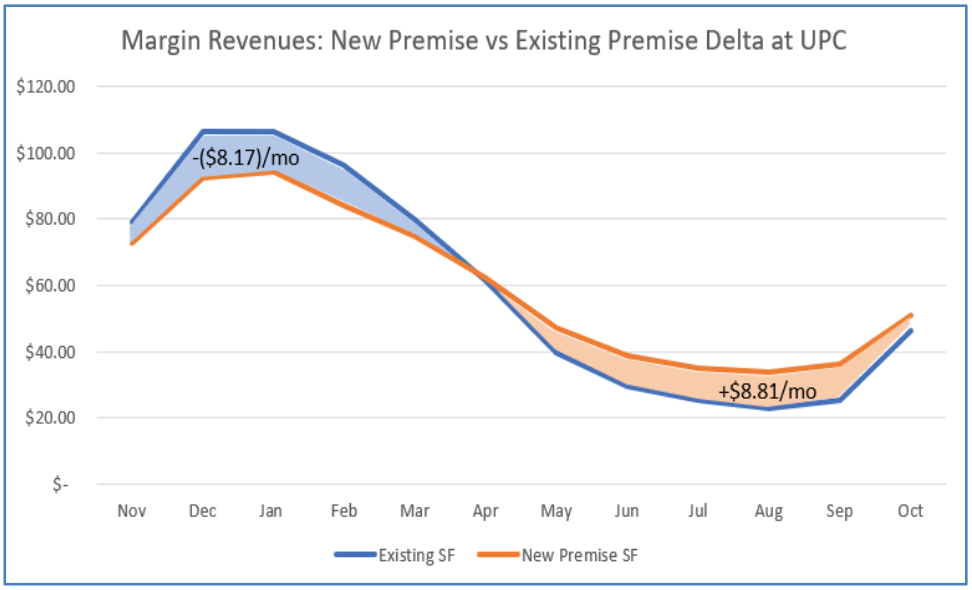
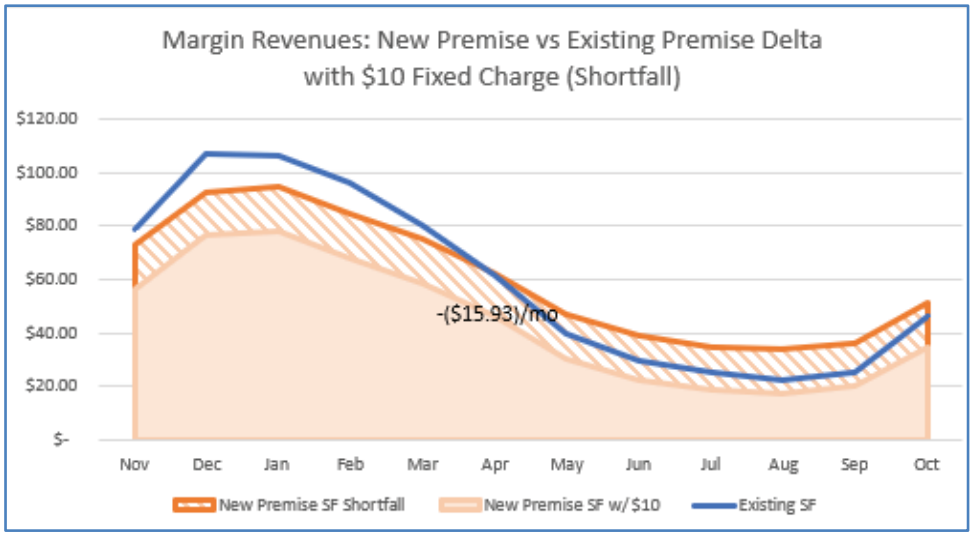


Chart 3 below shows the margin revenue shortfall for each month if no rate design change is made for the New Premises cohort. On an annualized basis, the shortfall is about $191 (or, about $16 per month) – roughly the same as the difference between the proposed New Premises and Existing Premises monthly fixed charge ($16.25 per month). As I explained earlier in my testimony, the shortfall (shown as the striped area in Chart 3) will fall on the base margin volumetric rate thereby impacting the higher-use Existing Premises cohort more than the lower-use New Premises cohort.

Chart 3



Q. How many annual therms does a New Premises customer need to use to breakeven on total billing cost compared to an Existing Premises customer?

A. If we assume a load profile that follows other New Premises customers, a New Premises customer would have to use about 531.9 therms annually to have the same total billing costs as an Existing Premises customer. This is usage that is about 18.4 percent higher than a typical New Premises customer. Due to the higher monthly fixed charge, this customer would still have winter bills that are roughly 7 percent lower relative to Existing Premises customers.

Q. At what level of usage would a New Premises customer see lower bills during winter months?

A. A New Premises customer will see roughly the same or lower bills in December through March at annual therm loads of 588.7 therms or less relative to an Existing Premises customer using 660.2 therms annually, assuming the New

Premises customer has a similar monthly load shape as an expected weather normalized new premises customer using 449.4 therms.

Q. What is the expected usage of a lower-income New Premises customer?

A. The Company estimates that of customers that are either enrolled in the bill discount program or have received bill assistance in the past 24 months as of March 2024 and that had initial service connection dates from 2013 through 2023 had average annual usage of about 464.7 therms.[85] This value is slightly higher than the expected New Premises UPC of 449.4 therms. The lower-income usage value of 464.7 therms is 12.6 percent lower than the usage level that would result in a total bill similar to that of an Existing Premises customer (531.9 therms) and 21.7 percent lower than the usage level that would result in higher winter bills compared to an Existing Premises customer (588.7 therms) *before* any bill assistance or bill discounts have been applied.

Q. At what therm level would winter bills be higher for a lower-income New Premises customer enrolled in the bill discount program compared to an Existing Premises customer?

A. At every bill discount program tier, winter bills would be lower for New Premises customers using average anticipated weather normalized usage of 464.7 therms relative Existing Premises customers using average annual anticipated weather normalized usage of 660.2 therms. A New Premises customer would need to

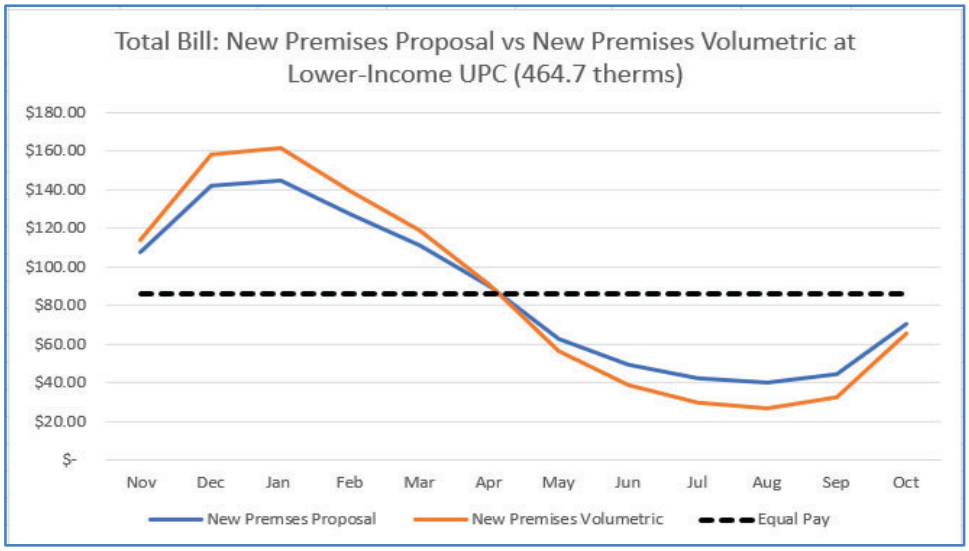
[85] Due to the low number of observations in this dataset, I did not perform a regression analysis similar in methodology to the UPC Forecast. Therefore, this value is not weather normalized, but does represent the average usage across 10 years' of variable (both warmer and colder than normal) weather.

use about 597.1 therms annually in order to have an expected January bill higher than an Existing Premises customer at the lowest bill discount program tier (Tier 3 - 15%). This is usage 28.5 percent higher than expected usage for a lower-income New Premises customer.

Q. What would be the impact of constructing a rate design that recovered the cost of service for New Premises customers on a volumetric, rather than monthly fixed cost, basis?

A. If the Company were to opt to recover the residential New Premises cost of service on the volumetric charge instead of the fixed charge (thus lowering the fixed charge), all New Premises customers (including lower-income customers enrolled at any tier in the bill discount program) would see higher winter bills on average compared to the Company's proposal. Chart 4 below shows the monthly total billing cost for a typical lower-income New Premises customer using 464.7 therms under the Company's proposal compared to a recovery of the same cost of service on a volumetric rate, as well as an "equal pay" scenario where the customer pays the same amount every month. The total annual cost recovery is the same in all three scenarios. As Chart 4 shows, the Company's New Premises proposal with the higher fixed charge results winter bills that are 8.9 percent lower on average compared to the scenario that leaves the monthly fixed charge at $10.00 and collects the remainder on the volumetric rate. The equal pay scenario, which is akin to one hundred percent fixed cost recovery, results in even lower winter bills but higher summer bills.

Chart 4



Since NW Natural only has the winter peaking season for residential customers, a higher monthly fixed charge has the benefit of shifting costs from the winter months when bills are highest to the summer months when bills are lowest. This has the added benefit of shifting costs from months when some customers may be experiencing higher electric utility bills, which can be dual peaking. Chart 5 below shows the same scenarios comparison as Chart 4, but now applies the second highest bill discount program tier (Tier 1 - 40%).

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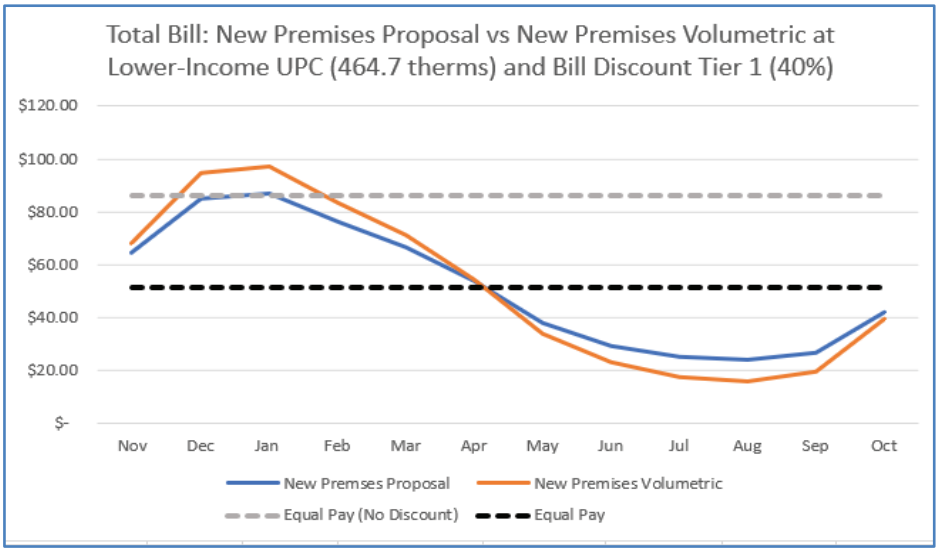
Chart 5



As Chart 5 indicates, at bill discount program Tier 1, the relative shape of the total billing costs between the New Premises proposal and New Premises volumetric scenarios is the same as shown in Chart 4. Winter bills under the New Premises proposal with the higher monthly fixed charge are still 8.9 percent lower on average. I have retained the equal pay line shown in Chart 4 as the dashed grey line to illustrate the discount being applied in Chart 5. At the Tier 1 discount, the highest winter bill is roughly equal to the pre-discount equal pay line.

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3. Equity Considerations in New Premises Fixed Charge

Q. The Coalition states, "in the same way that it hurts all customers, except by definition, a higher fixed charge hurts more for low income and energy burdened customer as they have less discretionary income."[86] How do you respond?

A. Just as every customer's financial situation and energy costs are different, I am skeptical that the Coalition's declaratory statement, which is offered with no evidence, is true for every customer. As I demonstrated in the charts above, a higher monthly fixed charge can result in lower winter bills when other energy costs may be increasing as well by working to smooth the Company's bills across the entire year. We know, in fact, that not every customer views the trade-off of lower winter bills for higher summer bills as a negative. The Company's Equal Pay plan, which spreads bills evenly throughout the entire year, is in practicality an individualized 100 percent monthly fixed charge (the Company's New Premises Customer Charge, by contrast, is about 31.2 percent for a typical customer). About 12 percent of the Company's Oregon residential customers have opted into paying a fixed bill through the Equal Pay plan, including about 3,300 customers that are also enrolled in the bill discount program.

[86] Coalition/100, Cebulko/53.

Q. Please describe the Coalition's testimony as it relates to principles of equity when considering the Company's proposed New Premises monthly fixed charge.

A. The Coalition testifies that the new premises customer charge is not in the public interest because (1) high customer fixed charges decrease the incentive for customers to efficiently manage their demand; (2) high customer fixed charges disproportionately impact lower-income customers; (3) the Company's proposal is a radical step to address what is at present a minor issue in the decoupling mechanism; (4) the Company's proposal moves away from the existing decoupling policy in favor of a new policy framework for fixed cost recovery – one that relies heavily on fixed charges; and (5) the Company's proposal sends conflicting financial signals to housing developers and customers, when combined with its LEA proposal, and significantly undercuts the value of federal incentive programs under the Inflation Reduction Act ("IRA").[87]

Q. How do you respond?

A. I address each of the Coalition's points regarding the New Premises Customer Charge separately:

1. As I have discussed earlier, the New Premises cohort will be largely comprised of newly constructed single-family residential dwellings. Newly constructed market-rate homes are likely to have highly efficient building envelops and new, high efficiency appliances. These homes essentially

[87] Coalition/100, Cebulko/48-49.

come with weatherization pre-installed and therefore there is a lower ability for customers in this cohort to drive additional conservation through the volumetric rate component. Further, even with the higher monthly fixed charge, about 68.4 percent of a New Premises customer's bill will be based on volumetric charges on an annualized basis. For the four winter months November through February, this ratio is 79.2 percent. This means that a large majority of these customers' bills during the heating season, when usage is the highest, can still be managed through demand side behaviors.

2. As I noted earlier, the New Premises cohort, on average, will be made up of customers that own, rent, or otherwise occupy a newly constructed single-family residential dwelling, live in a Census Tract with a higher household income compared to the statewide median household income, and are less likely to be enrolled in the bill discount program compared to a customer in the Existing Premises cohort. We can expect, however, that there will be some lower-income New Premises customers. I explain below that a higher monthly fixed charge can work to reduce winter bills when demand for energy is peaking and make bills more even and predictable throughout the year. I also explain below that New Premises customers are eligible for the same bill assistance and bill discount program tiers as Existing Premises customers. The bill discount program discounts on a whole-bill basis, therefore the fixed monthly charge is discounted the same amount as if it were a volumetric charge. Finally, I note that the New Premises monthly fixed charge is meant to prevent intra-class subsidization that would shift costs to Existing

Premises, a cohort that has a higher percentage of bill discount program enrollees.

3. As I discussed earlier in my testimony, the bifurcated Decoupling Mechanism alone does not mitigate intra-class subsidization between New Premises and Existing Premises customers. The magnitude of subsidization increases as new premises are connected to the system. It is most efficient, therefore, to pair the decoupling bifurcation with a rate design that avoids this issue now, before New Premises customer rates are established rather than after the lower decoupling baseline has been set. This will ensure New Premises rates, once established, are stable and predictable moving forward.
4. The Company's New Premises Customer Charge proposal is not about fixed cost recovery. The Company's proposal addresses its concerns about intra-class subsidies flowing from higher use Existing Premises customers to lower use New Premises customers employing a rate design that recognizes the fundamental usage differences between these cohorts. Nor is the proposal a "new policy framework for fixed cost recovery." The New Premises Customer Charge is only expected to be applied to about one percent of all Oregon residential customers by the end of the Test Year. Further, the Company has only proposed an Existing Premises monthly fixed charge of $10.00 which still leaves it on the lower end of residential monthly fixed charges among peer utilities.
5. The Company rejects the notion that the New Premises Customer Charge sends conflicting price signals that undercut federal incentive programs under

the IRA. The IRA is targeted to eligible "homeowners, including renters for certain expenditures, who purchase energy and other efficient appliances and products,"[88] whether electric or gas. The program is not targeted to new home buyers who are purchasing a home that already has high-efficient brand-new appliances, doors, and windows.[89] For natural gas conversions, the Company's LEA proposal, as discussed in NW Natural/4000, Therrien, provides for a higher construction allowance for lower expected natural gas usage, therefore incentivizing conversion applicants to install low use natural gas appliances while taking advantage of IRA tax credits for space and/or water heating equipment.

Q. The Coalition states it "imagine[s] the near-term impacts to the decoupling mechanism of adding new premise customers will be *de minimus* [sic]."[90] What do you estimate the impact will be?

A. As I discussed earlier, at the Test Year average new premises customer additions, the New Premises Customer Charge allocation methodology results in about $612 thousand of revenue requirement allocated to New Premises customers that otherwise would be spread to all residential customers on a

[88] US Department of Energy. *Making Our Homes More Efficient: Clean Energy Tax Credits for Consumers.* https://www.energy.gov/policy/articles/making-our-homes-more-efficient-clean-energy-tax-credits-consumers.

[89] The IRA has enhanced and extended the "New Energy Efficient Home Credit" under Internal Revenue Code 45L, which provides a tax credit for builders of new single family and multi-family homes that meet "Energy Star Single-Family New Homes National Program Requirement." The requirements are for good building envelope (windows, doors, insulation, etc.) and good HVAC (efficient gas or electric furnace, hot water, a/c, etc.). https://www.energystar.gov/about/federal-tax-credits/ss-45l-tax-credits-home-builders; https://www.irs.gov/credits-deductions/credit-for-builders-of-energy-efficient-homes.

[90] Coalition/100, Cebulko/51.

volumetric basis. This spread would more greatly impact the higher use Existing Premises cohort. This cohort, based on my previous discussion, is on average, more likely to have customers enrolled in bill discount program. As more New Premises customers connect to the system, in future rate proceedings there will be even more upward pressure on the volumetric rate in the absence of this proposed New Premises monthly fixed charge. The Coalition recognizes this potential longer-term issue, noting "it is also possible this discrepancy could eventually become a meaningful issue for timely cost recovery at some point in the future."[91] Although the $612 thousand impact is a small share of the overall residential class revenue requirement, this value increases to just under $1.2 million using the Test Year end of period customer additions on an annualized basis. This indicates the larger long-term impact in the absence of a rate design intervention as new customers are connected to the system.

Q. The Coalition states it "did not see Company analysis that quantifies the impact of new premise residential customers have on the decoupling mechanism, either in the near term or the long term."[92] How do you respond?

A. While I did not provide this impact figure in my Direct Testimony, I did describe how I apportioned the residential revenue requirement to New Premises

[91] Coalition/100, Cebulko/51.

[92] Coalition/100, Cebulko/51.

customers.[93] Further, I submitted a workpaper titled, "UG 490 – Exh. 1803 and 1804 – WP1 – Rate Spread and Rate Allocation Model" with a tab labeled "UG 490 Rate Design Proposal."

Q. The Coalition states that in "order to mitigate the Company's concerns" "the Company could modify its expected residential use-per-customer in the decoupling mechanism to account for the impact of the new premise residential customers."[94] How do you respond?

A. I discussed earlier in my testimony the need to make a rate design modification after bifurcating the Decoupling Mechanism to properly assign cost of service to the New Premises and Existing Premises customer sub-classes. If the Company begins to under collect its cost of service on all New Premises customers, it is unclear where the Coalition (and other Parties) believe the shortfall in revenue requirement would be allocated. Since revenue requirement is allocated to the residential class and then between new and existing premises, the volumetric rate picks up the remainder that is not allocated through the monthly fixed charge.

[93] NW Natural/1800, Wyman/78-79.

[94] Coalition/100, Cebulko/52.

Q. The Coalition recommends that the Commission not approve the new premises customer charge unless the Company demonstrates "imminent financial harm" without the charge.[95] How do you respond?

A. The Company disagrees with the Coalition's suggestion that rate design be based on an "imminent financial harm" standard. The threshold for sound rate design is not imminent financial harm, it is fairness to our customers. We believe this proposal is in the best interest of our existing and future customers: It results in a fair rate that appropriately apportions cost causality to new customers that join the system without subsidizing existing customers. Also, recall that we proposed a new rate design in this proceeding that provides a monthly fixed charge discount for multi-family residential customers; we made this proposal out of fairness and from listening to feedback from Staff, not because we felt that multi-family customers were at the risk of imminent financial harm if the proposal would not be approved.

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[95] Coalition/100, Cebulko/50.

Q. The Coalition states: "The Company is seeking permission to charge new premise residential customers $26.25 per month, an $18.25 per month increase (i.e., a 228% increase) over the current customer charge of $8 per month, and $16.25 per month more (i.e., 163% more) than the Company is proposing for existing residential customers in this rate case ($10 per month)."[96] How do you respond?

A. The Coalition's analysis is misleading for a couple of reasons:

1. The New Premises Customer Charge is a new rate that does not yet exist, it is not an increase over any other rate. There is no existing customer that will see the increases stated by the Coalition at the premises in which they currently reside. The charge is expected to largely be assessed to people who are not current customers or are existing customers who likely have usage consistent with the Existing Premises cohort who purchase newly constructed single-family residential homes at which point they are expected to have usage consistent with the New Premises cohort.
2. An appropriate comparison of cost differentials is to look at the entire bill, not just the fixed cost portion. The Coalition's analysis ignores the volumetric portion of the bill multiplied by the expected usage. If a current customer moves from an Existing Premises into a New Premises, their total expected bill would be a *reduction* of 11.2 percent. Of course, the exact number is based on the characteristics of each premises: Square footage, number of

[96] Coalition/100, Cebulko/46.

appliances, whether it has a furnace. On average, however, the New Premises is expected to be more efficient and drive a much lower usage profile compared to the Existing Premises.

Q. In addition to the New Premises Customer Charge for single-family residential customers, did the Company's proposal include a lower fixed charge for New Premises residential multi-family premises?

A. Yes. The Company proposed to apply the same $2.00 reduction to the fixed charge for existing multi-family residential customers to new multi-family residential customers. Therefore, the new multi-family residential fixed monthly charge would be $24.25.

Q. Please explain Parties' testimony on the New Premises Customer Charge as it relates to multi-family premises.

A. Staff is interested in the distribution of environmental justice communities comprising new premises customers with a stated concern as to multi-family units made up of affordable housing.[97]

CUB testifies that it believes 33 percent of new premises customers will be multi-family[98] and notes "this is concerning, since multi-family customers tend to be renters and/or lower-income."[99]

[97] Staff/300, Scala/19.

[98] CUB, citing the Company's response to UG 490 CUB DR 9, derives the 33 percent figure using end of Test Year New Premises customer counts. The value given in the response for New Premises single-family residential customers was 3,081 but should have been 4,607. The ratio for anticipated multi-family customers is therefore closer to 25 percent (1,525 divided by 1,525+4,607=6,132).

[99] CUB/200, Garrett/9-10.

The Coalition testifies the new premises customer charge works against reducing energy burden on low-income customers and is in conflict with the statewide housing goal of producing affordable housing.[100] The Coalition indicates that low-income customers are more likely to be low usage customers and will increase bills substantially for those customers.[101]

Q. What is the Company's response to Parties' concerns?

A. As I discussed earlier in my testimony, New Premises customers are on average more likely to live in Census Tracts that have higher median household incomes compared to the state-wide median and are less likely to be enrolled in the bill discount program relative to Existing Premises customers. With regards to multi-family dwellings, I note that each one must be individually metered for the New Premises Customer Charge to be applicable. Apartment buildings, including apartment buildings that are fully or partially affordable (in furtherance of the statewide housing goal of producing affordable housing), that are served under a master meter on a commercial rate schedule would not be assessed the proposed higher monthly fixed charge. Multi-family dwellings that are individually metered and that are affordable housing units would be eligible for the same energy assistance as all other residential customers as I explain further below. Note also, as I demonstrated in Chart 5 earlier, a higher monthly fixed charge like the proposed New Premises Customer Charge results in lower winter bills

[100] Coalition/100, Cebulko/50; Apter-Connolly/15.

[101] Coalition/100, Cebulko/50.

compared to commensurate rates that collect revenues via higher volumetric charges.

The Coalition states: "Lower-income customers are more likely to be low usage customers. Thus, an increase in the customer charge will increase monthly bills for low-usage customers (and will reduce monthly bills for high-usage customers)."[102] With regards to expected New Premises customers, as I noted earlier, lower-income customers use slightly more than the average New Premises customer (449.4 compared to 464.7 therms). Yet, a lower-income customer moving from an Existing Premises into a New Premises dwelling would be expected to see an overall bill decrease, not increase. A New Premises customer would need to have a 26.7 percent higher usage level to have higher winter bills compared to an Existing Premises customer (588.7 therms), *before* any bill assistance or bill discounts have been applied.

Q. Would low-income multi-family (and single-family) residential New Premises customers be eligible for the same energy assistance and bill discounts as residential Existing Premises customers?

A. Yes. To clarify, new customers (e.g., people who open new accounts) at existing multi-family (and single-family) premises will not be impacted by this proposal. Customers that reside in New Premises multi-family (and single-family) dwellings that are connected to the Company's system on or after November 1, 2024 will be eligible for the bill discount program under the same rules and at the same

[102] *Id*.

tiers as all other residential customers. The percentage of the bill that is discounted includes both the fixed and volumetric portions of the bill. For instance, a $50.00 bill discounted at the current Tier 1 level (25%) is $37.50 regardless of whether the fixed charge is $8.00 or $24.25.

D. Interplay Between New Premises Customer Charge and LEA

Q. What is the relationship between the New Premises Customer Charge and the Company's LEA proposal?

A. The higher New Premises Customer Charge simply ensures that the proposed rate design produces revenues from the new premises customers necessary to fully cover their cost of service. It acts as general input in the Company's LEA model, along with the proposed residential margin rate per therm and assumed customer UPC.[103] Together, these inputs create what the LEA model calls the "Revenue from New Connection Tariff."

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[103] For instance, see NW Natural/2002, Kravitz-Therrien (Input Output) of the Company's LEA model.

Q. CUB states: "The LEA economic modeling is highly dependent on collecting a much higher customer charge from 'new premise' customers … Without this substantial rate increase for new customers, the Company's LEA economic modeling implodes."[104] Similarly, Staff states: "Staff lowers the basic charge for a newly connected customer from $26.25 to $10.00 … In effect, this lowers the optimal LEA substantially."[105] What is your response?

A. By removing the New Premises Customer Charge, CUB finds that the LEA model "implodes," while Staff finds that that the model outputs a negative LEA value. Neither party appears to examine *why* the model behaves in this manner. As I have explained in my testimony, without rate design intervention, the New Premises cohort ***does not cover its cost to serve*** even with the Decoupling Mechanism bifurcation. This is precisely why the LEA model indicates New Premises customers are uneconomical without the higher new premises fixed charge. Moreover, as I have previously explained, existing customers will continue to subsidize new customers without this intervention.

This modeling result contradicts Staff's statement that "issues with variances in volumetric sales are best solved by the Company's decoupling mechanism rather than a blanket charge that applies to all new customers."[106] If the "issues" were solved by the Decoupling Mechanism alone, this solution is not

[104] CUB/200, Garrett/17.

[105] Staff/900, Dlouhy/44.

[106] Staff/1800, Shierman/20.

reflected in Staff's LEA model modifications that indicate a revenue shortfall for a new customer addition. In a similar vein, the Coalition states: "the Company could modify its expected residential use-per-customer in the decoupling mechanism to account for the impact of the new premise residential customers."[107] Again, if this statement were correct, then this modification should be accounted for in the LEA model. That is, if the Company is recovering its cost to serve New Premises customers at a rate necessary to mitigate intra-class subsidization through its Decoupling Mechanism, not the monthly fixed charge, then the margin revenues commensurate with the new premises connection would need to be reflected in the LEA model.

V. RATE SPREAD

Q. Please summarize the Company's rate spread proposal.

A. The Company proposed to spread incremental revenue requirement in such a manner that is responsive to the results of the LRIC study across all rate classes applying a methodology of caps and floors to both individual rate schedules as well as rate classes based on LRIC study indicated parity ratios. Overall, the Company's proposal equitably distributes the incremental revenue requirement such that the rate classes as a whole are moved closer to parity based on their indicated cost causation. The proposal described above is an incremental approach; it moves all rate classes closer to parity, but does so in a manner that works to minimize rate shock.

[107] Coalition/100, Cebulko/52.

Q. What was the methodology NW Natural proposed to use to spread the $154.9 million incremental revenue requirement?

A. I am reiterating my detailed methodology as presented in my Direct Testimony for ease of reference. NW Natural proposed a multi-step process for spreading the $154.9 million incremental revenue requirement:

1. Apply a cap equal to 1.04 times the overall incremental margin increase of 29.3 percent to RS 2 Residential. This cap is equal to a 30.5 percent margin increase.
2. Apply a cap equal to 1.05 times the overall incremental margin increase to RS 3 Commercial. This cap is equal to a 30.8 percent margin increase.
3. Apply a cap equal to 1.22 times the overall incremental margin increase to RS 27 Dry-Out. This cap is equal to a 35.7 percent margin increase.
4. Apply a floor equal to 0.50 times the overall incremental margin increase of 29.3 percent to the Transportation rate class plus any other rate schedules with a LRIC study indicated parity ratio above 1.75. This floor is equal to a roughly 14.6 percent margin increase.
5. After the caps and floor have been applied, allocate the remaining revenue requirement on an equal percent of margin basis among the remaining rate schedules, which include RS 3 Industrial, RS 31 and RS 32 Commercial Sales, RS 31 Industrial Sales Firm, and RS 32 Industrial Sales Interruptible. This step results in the same proposed margin increase for each of the remaining schedules, equal to roughly a 20.3 percent increase. The effect of

this step would be the same as applying a floor equal to 0.69 times the overall incremental margin increase in this case.

The caps of 1.04 for the Residential class, 1.05 for RS 3C, and 1.22 for RS 27 Dry-Out represent an approximation of the inverse mathematical relationship between the parity ratio of each rate class and schedule and unit parity of 1.00. For instance, Residential class (0.96 parity ratio): 1.00/0.96≈1.04.[108]

Q. Did Parties provide feedback on the Company's rate spread proposal methodology and present their own rate spread proposals?

A. Yes. Staff and AWEC each provided feedback on the Company's rate spread proposal and presented their own proposals.

Q. What is Staff's approach to rate spread?

A. Staff states: "Rate spread is the practice of allocating a company's revenue requirement to its various customer classes. Doing so effectively should balance concerns of economic efficiency, equity and energy justice concerns, and rate shock."[109] Staff agrees that there are many factors that go into balancing these conflicting concerns with "one goal of rate spread is to align the revenue earned from each customer class with the costs to serve each customer class according to the LRIC" and that "it is best practice to make the move towards parity deliberate enough that customers can properly adapt to these new different rates

[108] NW Natural/1800, Wyman/84-85.

[109] Staff/1800, Shierman/6.

and to signal that they are still operating under a regulatorily stable environment."[110]

Q. With regards to equity, Staff states: "to the extent that current modeling approaches employed with the LRIC look only at costs to the system, disparities in the system benefits received by different customer groups remain unaccounted for."[111] What is the Company's response?

A. The LRIC study is an economic modeling exercise that the Company values as a baseline for understanding the basis of cost causality among rate schedules and rate classes. The Company has argued that there are other important factors that should be considered, most importantly the idea that equitable distribution of the rate spread should be balanced with customer rate impacts. The Company's rate spread proposal considers these factors. Additionally, we also note that the Company addresses issues of equity after rate spread is determined (which impacts the rate class) through customer bill relief options, including the bill discount program, Oregon Low Income Gas Assistance, and the Gas Assistance Program, which are also complemented by federal assistance offerings such as LIHEAP.[112].

[110] Staff/1800, Shierman/6.

[111] Staff/1800, Shierman/7.

[112] For further discussion of these programs, please refer to NW Natural/2300, Tanaka.

Q. Does Staff agree with using the LRIC study as a basis for rate spread?

A. Staff "supports the use of LRIC as a baseline resource for rate spread proposals."[113] From that baseline, "evolutions to the rate spread cost allocation from the LRIC can avoid the burden of imposing an increase to a particular customer schedule that is unacceptably out of line with the overall increase and avoid allowing some schedules to receive a rate decrease in the context of a significant increase being imposed on most of the other customer schedules."[114] Staff feels, based on the results from the Company's LRIC study, that deviations appear appropriate as the "impact to customers in terms of price signals, affordability, and reasonableness would be substantial"[115] if the results were strictly followed. Staff notes, as the Company did in Direct Testimony, that Commission precedent is that it is not inclined to raise some rates while lowering others without compelling evidence that immediate action is warranted.[116]

Q. What was Staff's feedback to the Company's rate spread proposal?

A. Staff argues that the Company's rate spread proposal is not fair, stating that "it does not believe that concerns about the relatively large rate increases are properly addressed by the proposed spread of incremental revenue requirement."[117]

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[113] Staff/1800, Shierman/8.

[114] Staff/1800, Shierman/9.

[115] Staff/1800, Shierman/10.

[116] *Id*.

[117] Staff/1800, Shierman/13.

Q. Does Staff propose an alternative rate spread proposal?

A. Yes. Staff uses the Company's rate spread proposal as a starting point but adjusts the floor to "75 percent of the average percentage increase when determining the lowest possible rate spread allocation to each schedule."[118] The Company's lowest floor in its proposal, for comparison, is 21.8 percent, applied to RS 32 Industrial Sales Firm and RS 32 Industrial Sales Interruptible.

Q. What is the effect of Staff's proposal?

A. Staff's proposal has the effect of raising the allocated revenue requirement for all Schedule 31 and Schedule 32 customers relative to the Company's proposal.[119] Staff's methodology results in a lower rate spread for the RS 2 Residential class compared to the Company's methodology but maintains the same rate spread for the RS 3 General Commercial rate class.

Q. What is Staff's rationale for its rate spread proposal?

A. Staff notes that overall rate increases for all rate schedules should be narrower due to the level of rate increase proposed. Staff argues that the Company's rate spread proposal, in which "some rate schedules experience nearly a 19 percent rate increase, while others see only a 4 percent increase, is inequitable."[120]

Q. What is the Company's response to Staff's proposal?

A. Staff's proposal violates the principle of incrementalism and is unequitable for many customers in the RS 31 and RS 32 rate classes. Staff's mention of 4

[118] *Id*.

[119] *Id*.

[120] Staff/1800, Shierman/14.

percent increases for some rate schedules is based on total revenues and fails to consider the fact that the Company's proposal requests a 20.3 percent margin revenue increase from these same rate schedules. Table 2, provided later in my Reply Testimony, shows the margin and total revenue impacts of Staff's proposal on each rate schedule. Staff's proposal increases rates for many rate schedules in the RS 31 and RS 32 rate classes by more than an equal percent of margin (29.3 percent using the filed $154.9 million incremental revenue requirement). For instance, Staff's proposal would increase margin for RS 32 Industrial Sales Interruptible by 70.0 percent, about 2.4 times the equal percent of margin share, and increases margin for 32 Commercial Sales Interruptible by 65.2 percent (2.22 times the share). This proposal violates incrementalism because it would move these schedules whose parity ratios at current rates are well above 1.00 even further away from 1.00, not closer (an equal percent of margin increase maintains the same relative parity ratio at the proposed rates). The Company's LRIC study produced a 32 Industrial Sales Firm parity ratio at present rates of 1.91 indicating a 32.4 percent margin revenue target *reduction*; Staff's proposal would push the ratio higher with a 50.4 percent margin revenue increase (where a 29.3 percent margin revenue increase would simply maintain the 1.91 parity ratio at proposed rates). This issue persists at any proposed incremental revenue requirement as the relative increases would still remain well above the overall incremental margin increase.

Staff also indicates that the Company's rate spread proposal is "not fair," indicating that "Staff does not believe that concerns about the relatively large rate

increases are properly addressed by the proposed spread of incremental revenue requirement."[121] Staff's proposal, in addressing this concern, adjusts the spread for RS 2 Residential just slightly downward resulting in a $0.96 (or roughly one percent) reduction in an average residential monthly bill.

Q. Does AWEC support the Company's rate spread proposal?

A. No. AWEC states that the Company's rate spread proposal is "too complicated and applies different treatment to similarly situated rate schedules" using caps and floors that "are applied on an ad hoc basis to different rate schedules at differing levels."[122] AWEC indicates that the cap of 1.04 applied to the RS 2 Residential rate class does not have "a meaningful impact on rate class revenues relative to their calculated cost of service."[123]

Q. Does AWEC propose an alternative rate spread proposal?

A. Yes. AWEC proposes "a customer impact offset equal to 1.3 times the average rate increase to mitigate the increase to highly impacts rate schedules"[124] and "a uniform floor at zero percent."[125] AWEC does not indicate how it derived the customer impact offset cap equal to 1.3 times the average rate increase. AWEC applies the floor of zero percent to every rate schedule that the Company's LRIC study indicates is overpaying its cost of service, in addition to RS 3 Industrial and

[121] *Id*.

[122] AWEC/100, Mullins/47.

[123] AWEC/100, Mullins/48.

[124] AWEC/100, Mullins/4.

[125] AWEC/100, Mullins/48.

RS 32 Industrial Transportation Interruptible. AWEC's proposed adjustments to the LRIC study indicate that these two rate schedules are also overpaying their cost of service. AWEC's proposal is in response to what it characterizes as a "major rate increase at issue in this proceeding."[126]

Q. What is the effect of AWEC's proposal?

A. AWEC's proposal results in a rate spread that is 2.4 percent higher relative to the Company's for RS 2 Residential and 20.8 percent higher for RS 3 General Commercial on a total revenue basis. AWEC's proposal, due to application of the zero percent floor, results in no increase for all rate schedules in the RS 31 and RS 32 rate classes plus RS 3 Industrial, whereas the Company's rate spread proposal had revenue increases ranging from 3.6 percent to 14.7 percent for schedules in these rate classes.

Q. What is the Company's response to AWEC's rate spread proposal?

A. The Company's rate spread methodology is directly informed by the results of its LRIC study and was implemented for the purpose of addresses overall rate concerns while balancing principles of rate shock and incrementalism.[127] I will note that AWEC does not indicate how it arrived at a cap of 1.3 times the overall margin revenue increase. Nor does it explain why it reallocates the rate spread such as RS 2 Residential receives an increment at 1.07 times the overall margin revenue increase while giving RS 3 General Commercial (a schedule with a

[126] AWEC/100, Mullins/48.

[127] NW Natural/1800, Wyman/84.

similar parity ratio) an increase of 1.27 times. For comparison, the Company's rate spread proposal applies an increment of 1.04 and 1.05 times overall margin revenue increase for RS 2 Residential and RS 3 General Commercial, respectively.

Q. How does the Company's proposal compare to Staff's and AWEC's?

A. In Table 2 below, I present a comparison of the Company's rate spread to Staff's and AWEC's based on each proposal's effect of the filed $154.9 million incremental revenue requirement spread on percent of margin revenue and total revenue increase. I am using the filed revenue requirement such that I can make a direct comparison across all proposals. I have organized the proposals in order from lowest impact on the residential rate class (left) to the highest (right). As Table 2 shows, the Company's proposal falls in the middle of the proposed rate spreads.

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Table 2
Comparison of the rate spread proposals
by margin revenue and total revenue increase
at the initial filed incremental revenue requirement

					Revenue Requirement Effects					
					Staff		NW Natural		AWEC	
Line No.	Rate Schedule	Margin Revenue at Present Rates	Total Revenue at Present Rates	Parity Ratio at Present Rates (Unit Parity - 1.0)	Margin Revenue Increase (%)	Total Revenue Increase (%)	Margin Revenue Increase (%)	Total Revenue Increase (%)	Margin Revenue Increase (%)	Total Revenue Increase (%)
		A	B	C	D	E	F	G	H	I
					Lower		Middle		Higher	
1	02R	$ 360,714,887	$ 584,697,334	0.96	**28.4%**	**17.5%**	**30.5%**	**18.8%**	**31.2%**	**19.3%**
2	03C	$ 113,389,442	$ 207,588,681	0.95	30.8%	16.8%	30.8%	16.8%	37.1%	20.3%
3	03I	$ 2,405,057	$ 5,088,420	1.21	26.4%	12.5%	20.3%	9.6%	0.0%	0.0%
4	27R	$ 593,328	$ 1,051,370	0.82	31.0%	17.5%	35.7%	20.2%	38.0%	21.4%
5	31CSF	$ 10,045,606	$ 22,561,649	1.66	28.1%	12.5%	20.3%	9.0%	0.0%	0.0%
6	31CTF	$ 1,140,610	$ 1,133,412	1.95	14.6%	14.7%	14.6%	14.7%	0.0%	0.0%
7	31ISF	$ 3,467,751	$ 9,636,781	1.63	34.7%	12.5%	20.3%	7.3%	0.0%	0.0%
8	31ITF	$ 156,930	$ 155,940	2.34	14.6%	14.7%	14.6%	14.7%	0.0%	0.0%
9	32CSF	$ 14,016,743	$ 39,678,850	1.61	35.4%	12.5%	20.3%	7.2%	0.0%	0.0%
10	32ISF	$ 3,667,040	$ 14,798,305	1.91	50.4%	12.5%	14.6%	3.6%	0.0%	0.0%
11	32CTF	$ 994,454	$ 988,178	2.22	14.6%	14.7%	14.6%	14.7%	0.0%	0.0%
12	32ITF	$ 6,714,797	$ 6,672,424	1.65	14.6%	14.7%	14.6%	14.7%	0.0%	0.0%
13	32CSI	$ 2,566,247	$ 13,398,486	1.30	65.2%	12.5%	20.3%	3.9%	0.0%	0.0%
14	32ISI	$ 2,990,958	$ 16,774,985	1.46	70.0%	12.5%	20.3%	3.6%	0.0%	0.0%
15	32CTI	$ 515,000	$ 511,750	2.64	14.6%	14.7%	14.6%	14.7%	0.0%	0.0%
16	32ITI	$ 5,539,411	$ 5,504,455	1.25	14.6%	14.7%	14.6%	14.7%	0.0%	0.0%
17	33T	$ 0	$ 0	1.00	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Total	**$ 528,918,261**	**$ 930,241,019**		**29.3%**	**16.7%**	**29.3%**	**16.7%**	**29.3%**	**16.7%**

As Table 2 indicates, the Company's proposal falls between Staff's and AWEC's when comparing the impact of the filed revenue requirement on percentage of both margin revenue and total revenue increase. Staff's proposal has higher or the same increases for the large commercial and industrial rate schedules in the RS 31 and RS 32 rate classes relative to the Company's proposal and gives higher than equal percent of margin increases to several rate schedules with parity ratios above 1.00 at current rates. Increases for these rate classes are used to offset the increases for RS 2 Residential and RS 27 Dry-Out. AWEC's proposal gives no increment to the RS 31 and RS 32 rate classes,

which puts upward pressure on the revenue increases for RS 2 Residential, RS 3 General Commercial, and RS 27 Dry-Out relative to the Company's proposal.

Q. Is the Company proposing an update to its rate spread methodology?

A. No. As shown above in Table 2, the Company's rate spread approach is the middle ground between all parties that submitted a proposal with regards to impacts to RS 2 Residential. The Company's proposal is the only proposal that equitably distributes the incremental revenue requirement such that the rate classes as a whole are moved closer to parity based on their indicated cost causation (i.e., incrementalism) but does so in a manner that works to minimize rate shock. Staff's proposal, as I explain above, violates incrementalism and does so with a very small reduction to the RS 2 Residential rate relative to the Company's proposal. AWEC's proposal over applies the incrementalism principle which results in larger increases to RS 2 Residential and especially to RS 3 General Commercial that is not responsive to the relative LRIC study indicated parity ratios between these two rate schedules. Both Staff and AWEC present their proposals as a more equitable approach for rate spread yet both approaches differ wildly on the application of incremental revenue requirement to the residential rate class, as well as the large commercial and industry rate classes. The Company's approach, as shown above in Table 2, provides a balance that recognizes the relative cost causation of all rate schedules while attempting to minimize rate shock.

Q. Does this conclude your Reply Testimony?

A. Yes, it does.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Reply Testimony of Gregg H. Therrien

LINE EXTENSION ALLOWANCE
EXHIBIT 4000

June 4, 2024

EXHIBIT 4000 – REPLY TESTIMONY – LINE EXTENSION ALLOWANCE

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I. INTRODUCTION AND SUMMARY

Q. Are you the same Gregg H. Therrien who filed Direct Testimony and Supplemental Testimony (jointly with Zachary D. Kravitz), on behalf of Northwest Natural Gas Company dba NW Natural ("NW Natural" or the "Company")?

A. Yes. I presented NW Natural/1900, Therrien, and NW Natural/2000, Kravitz-Therrien.

Q. What is the purpose of your Reply Testimony?

A. The purpose of my Reply Testimony is to address the Public Utility Commission of Oregon ("Commission") Staff, the Oregon Citizens' Utility Board ("CUB") and the Coalition positions that the Company's proposed Line Extension Allowance ("LEA"), as described in my Direct Testimony and our Supplemental Testimony, should be rejected. I will rebut point-by-point to each of these entities' assertions and detail why their criticisms and alternative recommendations are flawed and without merit, and why the innovative approach in the Company's proposed LEA is fair, designed to support the state's decarbonization efforts (i.e., any new/future Oregon greenhouse gas ("GHG") regulations that take the place of the invalidated Oregon Climate Protection Plan ("CPP")), a balanced and economical approach to adding new gas customers that desire service from NW Natural, and should be approved.

Q. Please summarize your testimony.

A. My testimony consists of three main sections: rebuttal of Staff Witness Dlouhy, rebuttal of CUB Witness Garrett and rebuttal of Coalition Witnesses Apter-Connelly

and Cebulko. I conclude with affirmation that the Company's proposed LEA meets the directives of the Commission and should be approved.

Q. Do you sponsor any exhibits with your Reply Testimony?

A. Yes. I am sponsoring the following:

- NW Natural/4001, Therrien: CUB's response to NW Natural DR 2
- NW Natural/4002-4007,Ther rien: Revised LEA DCF Model supporting calculations
- NW Natural/4008, Therrien: Survey of U.S. Line Extension Policies

II. OVERVIEW OF NW NATURAL'S PROPOSED LEA

Q. Please summarize how the Company's LEA proposal includes the costs of complying with Oregon GHG regulations.

A. Pursuant to the Commission's directives in Order No. 22-388, my Direct Testimony included a proposed LEA model that had the Company's best and reasonable estimates of costs of complying with the CPP. The CPP, however, was subsequently invalidated by the Oregon Court of Appeals.[1] After the CPP was invalidated, I updated the LEA model in Supplemental Testimony to include a forecast of complying with future Oregon GHG regulations.[2] The LEA model in Direct Testimony, as well as the update in Supplemental Testimony, rely on first maximizing credits that will likely be available to NW Natural and then utilize Renewable Natural Gas ("RNG") at conservatively high-cost estimates.

[1] NW Natural/1900, Therrien/27-28.

[2] NW Natural/2100, Therrien-Kravitz/23-27.

Q. Please briefly summarize the economic principles underlying the Company's LEA proposal to connect new customers.

A. New premises customers should receive an LEA that is commensurate with the anticipated delivery margin revenues that customer will pay over the LEA term offset by the initial service connection investment as well as on-going variable costs. Usage is an important variable in determining anticipated delivery margin revenues (derived from the per therm distribution margin charge) as well as the variable costs to serve that new premises customer. Notably, the Company included 100 percent of the variable costs of a new premises customer's compliance with a climate policy program (i.e., the per therm Proxy CPP costs) in its proposed LEA model. By incorporating these costs, higher usage new premises customers who bring more emissions to the system will bear more costs to bring these emissions under compliance relative to lower usage new premises customers. Evaluating the delivery margin revenues against the variable costs in the Company's discounted cash flow ("DCF") model produces a mathematical result (i.e., the net present value calculation) that indicates a lower LEA for higher usage new premises customers and a higher LEA for lower usage new premises customers. In other words, while higher usage new premises customers produce more anticipated delivery margin revenues relative to lower usage new premises customers, these higher revenues are more than offset by the additional variable Proxy CPP costs associated with emissions compliance caused with their higher usage. This requires a lower LEA to produce a positive net present value result for higher-usage new premises customers.

Q. Absent the changes included in the Company's LEA proposal, is there a potential for subsidization from new customers to existing customers?

A. Yes. If a new customer paid more than the amount of revenues to clear the project hurdle rate, existing customers would benefit; they would not be harmed. On the other hand, a new customer would be harmed if they paid more than what is financially required of them to prevent existing customers from subsidizing their service connection to the system.

Q. How does the Company's tiered LEA address this issue?

A. The Company has proposed a tiered LEA structure that results in lower usage customers receiving a higher allowance relative to higher usage customers. Under the proposed LEA, higher usage customers receive a lower LEA than lower-use customers. This LEA structure is a function of two drivers in the Company's LEA methodology. First, the LEA methodology captures the expected revenues from a new premises customer who has a higher monthly fixed customer charge than an existing customer. Second, the Company included 100 percent of the costs of a new premises customer's compliance with a climate policy program (i.e., the per therm Proxy CPP costs) in its proposed LEA construct.

Q. Does the new premises customer charge also help to address the potential for subsidization?

A. Yes. As detailed in the Direct and Reply Testimony of Company Witness Wyman,[3] the Company is proposing a new premises Rate Schedule 2 Residential sub-class

[3] NW Natural/1800, Wyman, and NW Natural/3900, Wyman.

rate with a higher monthly fixed charge compared to the existing fixed charge tariff rate. Due to the lower annual average weather normalized use-per-customer associated with new premises customers relative to existing customers, the higher fixed charge allows the Company to maintain the same variable price signal for all residential customers on an intra-class level. This higher fixed-to-variable rate design flattens the anticipated delivery margin revenues from new premises customers while enabling the Company to collect its full cost of service, thereby avoiding an intra-class subsidy between existing and new premises residential customers.

Q. How does the LEA address the future Oregon GHG compliance costs?

A. By incorporating the per therm Proxy CPP costs, higher usage new premises customers who bring more emissions to the system will bear more costs to bring these emissions under compliance relative to lower usage new premises customers. Evaluating the delivery margin revenues against the variable costs in the Company's DCF model produces a mathematical result (i.e., the net present value calculation) that indicates a lower LEA for higher usage new premises customers and a higher LEA for lower usage new premises customers.

Q. Please summarize how the inputs to the LEA model will help avoid intra-class subsidies.

A. The per therm Proxy CPP costs ensure new premises customers are fully covering their costs to comply with a climate policy program prior to connecting to the system, and the higher new premises fixed charge ensures that the proposed rate design produces revenues from the new premises customers necessary to fully

cover their cost of service. Incorporating these two drivers into the Company's LEA proposal works to avoid intra-class subsidies.

Q. Has the Company updated its LEA modeling in response to the testimony provided by other witnesses?

A. Yes. As shown in NW Natural/4002-4007, Therrien, the Company has updated its Discounted Cash Flow ("DCF") modeling assumptions to reflect the following two assumption changes to the DCF:

1. Revised non-growth capital expenditures; and
2. Increase the unit cost of RNG from $22.00 to $25.00 by year 18 of the DCF model.

Q. What are the results of the revised DCF?

A. Table 1 below compares the revised DCF model LEA results to that filed in my Direct Testimony and updated in the Supplemental Testimony:

Table 1: Revised DCF Model LEA Results

UPC (Therms)	0-250	251-450	451-650	651+
Direct Testimony LEA	$3,600	$3,100	$2,600	$1,800
Supplemental Testimony Proposal	**$3,700**	**$3,300**	**$2,950**	**$2,200**
Revised LEA	**$3,400**	**$2,900**	**$2,500**	**$1,700**
Difference: Higher / (Lower)	**($300)**	**($400)**	**($450)**	**($500)**

As Table 1 indicates, the two changes made to the revised DCF calculation reduce the proposed LEA for all four usage tier levels, however, the LEA remains positive.

Q. Did NW Natural update its modeling for illustrative purposes only, or has NW Natural modified its LEA proposal in this Reply Testimony?

A. Table 1 above represents NW Natural's revised proposal.

Q. Is the Company proposing a "set it and forget it" LEA in this case?

A. No. The Company fully recognizes that the assumptions and inputs that inform the LEA may change over time. In particular, the Company expects that there will be greater certainty regarding GHG compliance costs after the Oregon Department of Environmental Quality's ("ODEQ") concludes its rulemaking to establish future Oregon GHG regulations, and that assumptions regarding RNG pricing may evolve as the RNG market matures. Further, routine updates to model assumptions occur as a result of new rates being implemented (e.g., updated DCF cost of capital, billing delivery rates, etc.). Accordingly, the Company expects that it will need to update the LEA with new model inputs periodically and plans to do so at least every time it files a rate case.

III. REPLY TO STAFF WITNESS DLOUHY

Q. Please summarize Staff's Opening Testimony addressing the Company's proposed LEA.

A. Staff questions whether the Company's LEA analysis takes into account the "true" cost of CPP or decarbonization, best practices that Staff has pushed for in other dockets, or findings from other jurisdictions. Staff also questions whether the LEA proposal is a "least regrets" action to reduce customer count. Finally, Staff also expresses concern that the LEA proposal could lead to greater stranded asset costs, to the detriment of customers that may not be able to afford to electrify their homes.[4]

[4] Staff/900, Dlouhy/33.

Staff provides a critique of the Company's LEA modeling assumptions, including: (1) the assumption regarding the use of a 25-year payback period, (2) the assumption regarding RNG cost of $22/MMBtu; (3) the revenue multiplier assumption; (4) the assumptions regarding new non-growth capital expenditures; and (5) the home occupancy assumptions in the first few months following new home construction.[5]

Based on these concerns, Staff recommends that the Commission take one of two actions: (1) eliminate NW Natural's residential LEA entirely, or (2) maintain its previous decision on phasing out residential line extensions to a level equivalent to the 2x margin beginning on November 1, 2025, and then 1x margin on November 1, 2026, then entirely eliminate residential LEAs by November 1, 2027.[6]

I will address Staff's broader arguments, model critiques, and alternative proposals in turn.

A. Reply to Staff's LEA Policy Concerns

Q. Staff broadly asserts that the proposed LEA "fails to take into account the true cost of CPP or decarbonization."[7] What is the basis of Staff's argument?

A. Staff finds fault in several of the Company's modeling assumptions. In short, Staff questions the CPP compliance costs assumed in the model via the price of RNG, questions the payback assumptions, and questions the revenue assumptions from

[5] Staff/900, Dlouhy/36.

[6] Staff/900, Dlouhy/33.

[7] Staff/900, Dlouhy/33.

new customers.[8] Staff's critiques of the modeling are discussed in greater detail below (Section III.B).

Staff also questions whether the Company's assumptions regarding RNG are too optimistic, raising again a concern from NW Natural's Integrated Resource Plan ("IRP"), docket LC 79, and expresses a concern that an LEA policy that continues to support future Company investments increases the potential for future stranded asset risk.[9]

Q. How do you respond?

A. Staff highlights concerns that speak more broadly to questions about the future role of natural gas in the delivery of energy to Oregon customers, availability of RNG, and the possibility that customers may leave the natural gas system. The Reply Testimony of Zachary D. Kravitz[10] addresses these issues, and explains that here, Staff presupposes a worst-case outcome which does not reflect current conditions. NW Natural is not seeing customers leave the system in droves—on the contrary, NW Natural continues to experience growth. Additionally, the Company's assumption about RNG pricing and availability are informed by what we know today. To that end, NW Natural has proposed an LEA that is responsive to the Commission's guidance in Order No. 22-388, and that appropriately reflects the environmental and regulatory context as it exists today.

[8] Staff/900, Dlouhy/34.

[9] Staff/900, Dlouhy/34.

[10] NW Natural/2200, Kravitz.

Staff, on the other hand, seems overly pessimistic and urges planning for a worst case scenario—and one which we are not seeing bear out in the Company's new customer growth.

The Company's LEA analysis does include a proxy for the compliance costs associated with any future Oregon GHG regulations.[11] Table 4 of my Direct Testimony clearly shows the assumed RNG cost per MMBtu added to each year of the LEA DCF model.[12] It bears noting, however, that the model used for the LEA utilizes long-term assumptions that by their nature are uncertain. In my professional experience, long-term forecasting will always be imperfect, regardless of the exercise. To the extent that it seems that NW Natural is doing something new with its LEA that has not yet been done in other dockets, that is precisely the point of the proposal. The Commission charged the Company with specific guidance concerning the development of an alternative LEA approach that takes into account the carbon compliance costs, and that is exactly what the Company has done.

[11] Since the CPP was invalidated, there are no compliance costs associated with it. Therefore, I will be referring to the cost of complying with future Oregon GHG regulations that have not been enacted at the time of this testimony.

[12] See also NW Natural/2000, Kravitz-Therrien/15-19.

Q. Finally, Staff asserts that the Company's proposal does not reflect "findings from other jurisdictions," referencing decisions from the California Public Utilities Commission ("CPUC") and the Washington Utilities and Transportation Commission ("WUTC") that eliminate or propose a shorter term for LEAs.[13] How do you respond?

A. As discussed above, the LEA proposal advanced in this case is, in part, based on specific directives provided by the Oregon Commission. It may be instructive to review the direction and decisions of other state regulatory agencies, but the ultimate policy decided here is to be Oregon's own.

Q. Given Staff's discussion of the CPUC and WUTC decisions, do you have any comments regarding these two jurisdictions?

A. Yes. While I am not a lawyer, there is additional context for the CPUC and WUTC decisions regarding LEAs that Staff did not highlight. In 2022, California recently eliminated residential LEAs and permitted non-residential LEAs only under special circumstances. However, it is my understanding that the CPUC was acting in response to a building decarbonization mandate that established a policy preference for electrification of new buildings. There, the CPUC implemented a policy choice that had been made by the California legislature. It is my understanding that Oregon has no comparable legislative mandate promoting electrification.

[13] Staff/900, Dlouhy/28-29, 33.

With respect to Washington, the WUTC recently modified its LEA policy, but it is my understanding that the LEA policy changes are narrower than what is suggested by Staff. It is my understanding that recent changes in LEAs for Washington utilities are a product of settlement, not WUTC order.

Q. Staff highlights the line extension policies from California and Washington, but does Staff address any other jurisdictions?

A. No. Staff ignores the policies of the vast majority of other states, including many with decarbonization goals. NW Natural/4008, Therrien to this testimony includes a listing of LEA policies across the United States. As this exhibit shows, the vast majority of states continue to employ LEAs, many of them using a consistent construct as that proposed by the Company, which is based on a DCF analysis, and are comparatively less restrictive given the proposed inclusion of compliance costs associated with future Oregon GHG regulations in the proposed NW Natural LEA calculation.

B. Reply to Staff's LEA Model Critiques

Q. Witness Dlouhy lists five "questionable assumptions" in the Company's proposed LEA model.[14] Please respond to the first assumption regarding the Company's choice to use a 25-year payback period.[15]

A. Here, Staff Witness Dlouhy challenges the term of the DCF calculation. In response to concerns raised in the Company's last rate case, the Company

[14] Staff/900, Dlouhy/35-36.

[15] Staff/900, Dlouhy/36-37.

instructed me to model the DCF using a 25-year term, which is five years less than the previous 30-year DCF model term. Now, Staff Witness Dlouhy counters with a *15-year term* recommendation – which is five years fewer than past Staff recommendations.[16] Staff Witness Dlouhy provides no theoretical or analytical support for this new recommendation.

Q. Given the trends NW Natural has experienced with customer retention, is the 25-year term conservative?

A. Yes. As an initial matter, the 30-year assumption previously used by the Company is a conservative approach because the Company's customer count in Oregon has increased for decades and continues to grow. Further, the 25-year term that I proposed in the DCF model is reasonable because of the expected life of appliances, the uncertainty of fuel-switching in the future given historical preference to maintain gas appliances, and the potential high costs to convert a home to all-electric.[17] A recent presentation to the U.S. Energy Information Agency ("EIA") by Guidehouse titled "EIA – Technology Forecast Updates – Residential and Commercial Building Technologies – Advanced Case" (the "Guidehouse Report") states that the average life of a gas furnace is 22.5 years.[18] The proposed 25-year term is also synchronized with the development of revenue

[16] Staff/900, Dlouhy/35.

[17] NW Natural/1900, Therrien/21.

[18] In the Residential Furnaces EERE 2022 Notice of Proposed Rulemaking (NOPR) Technical Support Document (TSD), an average lifetime of 22.5 years is calculated for gas-fired furnaces (North). Lifetime range was calculated using the Weibull Distribution in the Residential Furnaces EERE 2022 NOPR. Guidehouse Report, Appendix B page 11.

requirements for existing system revenue requirements[19] and non-growth capital expenditure revenue requirements[20] used in the proposed DCF analysis.

Q. Please respond to Staff Witness Dlouhy's second assertion that the Company's assumed cost of compliance with future Oregon GHG regulations (RNG at $22.00/MMBtu) is too low and Staff's alternative recommendation to modify the assumed cost to $30.00/MMBtu.[21]

A. First, the proposed DCF model is calculated on a real dollar basis (i.e., adjusted for inflation; a constant dollar basis). Holding the cost of compliance with future Oregon GHG regulations (RNG prices) constant at a unit price considerably higher than previous Company analyses is conservative and appropriate. Second, it is difficult to estimate the cost of a substitute and emerging commodity such as RNG, which can be acquired from several different production means (e.g., wastewater treatment plants, landfills, organic composting, etc.) and a developing supplier base.

While the Company considers the Staff recommendation of $30/MMBtu for RNG to be too high,[22] I have performed an alternative DCF analysis and supporting calculations as shown in Exhibits 4002-4007 that includes a conservative RNG cost assumption, rising from $22.00/MMBtu to $25.00/MMBtu

[19] NW Natural/1903, Therrien.

[20] NW Natural/1904, Therrien.

[21] Staff/900, Dlouhy/37-38.

[22] Staff/900, Dlouhy/38.

over the term of the analysis.[23] The results of this assumption change (as well as other changes described below) is described further below in this Reply Testimony.

Q. Please respond to Staff Witness Dlouhy's third assertion that the future Oregon GHG compliance costs revenue multiplier for a new customer is unknown because of potential future rate design changes.[24]

A. One of the assumptions in the Company's proposed LEA DCF model is that new customers would pay for future Oregon GHG compliance costs, and the costs charged to new customers follow the trajectory of the decreasing emissions cap.[25] Staff Witness Dlouhy asserts that this assumption is a "gross overestimation of revenues"[26] yet offers no alternative assumption or basis for changing the assumption other than the potential for future rate design changes. Without any supporting evidence to the contrary, the assumed new customer revenue assumption for future Oregon GHG compliance costs should remain unchanged (as assumed by Staff Witness Dlouhy for purposes of his Opening Testimony), and the unfounded assertion that the proposed LEA estimates should be interpreted as the "highest possible" LEA should be rejected.

[23] *See* NW Natural/4006, Therrien.

[24] Staff/900, Dlouhy/38-40.

[25] *See* NW Natural/1906, Therrien/Lines 16-18.

[26] Staff/900, Dlouhy/40.

Q. Please respond to Staff Witness Dlouhy's fourth assertion that the assumed non-growth capital expenditures forecast is "exceptionally high".[27]

A. One of the components of the revised LEA model is recognition that a new customer will contribute to the cost of future non-growth capital expenditures, to the benefit of existing customers. This concept is not challenged by Staff Witness Dlouhy; only the amount of the future non-growth capital spending is at issue. In his testimony, Staff Witness Dlouhy suggests that the Company has not adequately removed new customer-related costs (a portion of construction permits and meters). In response, the Company has provided me with a revised non-growth capital expenditure forecast adjusted for lower meter and permit costs,[28] which I have incorporated into the revised DCF calculation. This change has a very minor impact on the results of the various DCF calculation runs supporting the Company's four-tier LEA proposal shown in Table 1 above.

Q. Please respond to Staff Witness Dlouhy's fifth assertion that new customer line extensions will have periods of unoccupied households.[29]

A. In response to Staff DR 135, the Company quantified the time between a line extension installation and the commencement of service at approximately four months. The DCF calculation I have performed in the proposed LEA utilizes the Microsoft Excel© NPV function, which assumes that all investment is made at the

[27] Staff/900, Dlouhy/40-42.

[28] NW Natural/4004.

[29] Staff/900, Dlouhy/42-44.

beginning of the year.[30] This is a conservative financial assumption, as it is far more likely that the new gas installation would be performed in a period less than one year, and in the first year of service. Stated differently, the NPV calculation assumes a "year zero" investment and does not include the value of the new customer revenues until year 1. Therefore, the calculation theoretically would cover any time lag as described by Staff Witness Dlouhy and no further adjustment is warranted.

Additionally, I understand the timing of unoccupied households is mitigated by the Company's Rate Schedule 27, which is its Residential Heating Dry-Out Service. This rate schedule is available to home builders, developers, and contractors during the period that a residential dwelling is under construction. Upon occupancy of the dwelling, Rate Schedule 27 is terminated, and the new occupant is placed on Rate Schedule 2. While there would be differences in expected revenues between these schedules to the extent that a new premises was on Rate Schedule 27 for a short period of time, the impact to the LEA would be de minimis. It is also worth noting that a new residential conversion customer (i.e., establishing gas service to an existing home) would unlikely have any delay in service because that customer is already living in the premises that is converting to natural gas service and would require gas service immediately.

[30] "The NPV investment begins one period before the date of the value1 cash flow and ends with the last cash flow in the list. The NPV calculation is based on future cash flows." Microsoft Excel "Help" function description of the NPV function.

Q. Does Staff Witness Dlouhy propose further modifications to the proposed LEA model assumptions?

A. Yes. Staff Witness Dlouhy recommends that the LEA model should reflect a lower monthly fixed customer charge (reduced from $26.25 to $10.00), noting that this change lowers the LEA substantially, and proposes that the assumed Weighted-Average Cost of Capital ("WACC") should be reduced consistent with Staff's proposed ROE midpoint and the stipulated cost of long-term debt.[31]

Regarding the fixed charge, Staff Witness Dlouhy seems to miss the point of the Company's new premise higher monthly fixed customer charge, which is to ensure that all customers are paying their cost of service and that the Company's existing customers are not unfairly subsidizing the Company's new customers. This updated fixed charge is discussed in the Direct and Reply Testimony of Robert J. Wyman.[32]

Regarding the WACC, I cannot at this time justify any change of WACC assumptions given the stage of the rate case proceeding. The Company will update the final LEA model with the Commission-approved fixed customer charge and WACC during the compliance filing stage of this proceeding.

[31] Staff/900, Dlouhy/44.

[32] NW Natural/1800, Wyman and NW Natural/3900, Wyman.

Q. Staff presents an alternative LEA calculation using NW Natural's DCF model as adjusted for Staff's revised model assumptions which produces a negative LEA.[33] How do you respond?

A. As detailed above, I fundamentally disagree with many of Staff's proposed critiques and modifications to the model and recommend that they be rejected. However, as I previewed in Section II, I updated NW Natural's analysis to reflect revised assumptions for non-growth capital and RNG pricing in the revised DCF calculation, which reduced the proposed LEA for all four usage tier levels. However, the reduction was modest and certainly did not result in a negative LEA. The results of this updated analysis is shown in Table 1 above and NW Natural/4005, Therrien.

C. Reply to Staff's Recommendation

Q. How do you respond to Staff's primary recommendation that the Company eliminate the LEA entirely and Staff claims that this would not result in existing customers subsidizing new customers?[34]

A. NW Natural strongly disagrees with Staff's proposal to eliminate the LEA entirely, and, as I discuss at length in my Direct Testimony, does not agree that an LEA results in a subsidy from existing customers. Staff ignores the fact that under a no-LEA scenario, any possible subsidy would be one-directional, instead flowing only from new customers to existing customers. Eliminating the LEA can only

[33] Staff/900, Dlouhy/44-45.

[34] Staff/900, Dlouhy/46.

result in new customers providing a subsidy to existing customers because new customers will pay 100 percent of their connection costs and existing customers benefit from the revenue these new customers generate that cover common costs of existing customers.[35] NW Natural's LEA proposal, on the other hand, is designed to ensure that existing customers are not subsidizing new customers and vice versa.

Q. How do you respond to Staff's alternative proposal that the Commission continue the path to phasing out the LEA set forth in Order No. 22-388?[36]

A. While this alternative is an improvement over eliminating the LEA entirely, NW Natural does not support this proposal. Instead, the Commission should adopt the Company's thoughtful approach to restructuring its LEA, which carefully takes into account the feedback that the Commission provided to NW Natural in Order No. 22-388 and appropriately reflects the benefits of adding lower use customers to the Company's system.

IV. REPLY TO CUB WITNESS GARRETT

Q. Please summarize CUB Witness Garrett's Opening Testimony on the subject of the LEA.

A. CUB Witness Garrett presents an unsupportable theory that the Company's proposed LEA is somehow linked to a loss of price competitiveness to alternative fuels. Further, he attempts to paint natural gas as a luxury item, and that the

[35] NW Natural/4004, Therrien.

[36] Staff/900, Dlouhy/46.

Company may not be fully transparent in the way it communicates the cost of new gas service (i.e., proposed changes to Residential tariff Schedule 2) to prospective customers. His analysis attempts to quantify "savings" that a prospective customer could enjoy if they avoided gas altogether and (presumably) went to a full-electric appliance household. Lastly, CUB Witness Garrett challenges the assumptions of the DCF model and asserts that the model as proposed will lead to utility stranded costs.[37]

A. Reply to CUB's Policy Concerns

Q. Please summarize CUB Witness Garrett's policy concerns regarding the LEA.

A. CUB Witness Garrett asserts that "[t]he Company's LEA design implies that the product the Company delivers is becoming less cost-competitive, and that the ideal NW Natural customer hooks up to the system but uses little to no therms of gas."[38] Specifically, CUB takes issue with the fact that the LEA incentivizes the connection of lower usage customers, and suggests that the customers that may install these lower usage appliances may not stay on the system in the long term, or for long enough to recover the cost of the LEA.[39] CUB Witness Garrett also comments that the LEA does not necessarily incentivize the installation of higher efficiency

[37] CUB/200, Garrett/10-27.

[38] CUB/200, Garrett/11.

[39] CUB/200, Garrett/14.

appliances, like a high efficiency furnace, because it instead incentivizes low use "luxury" appliances.[40]

Q. How do you respond to CUB's claim that the LEA design demonstrates that natural gas is becoming uncompetitive with electric service?

A. At a basic level, the Company's proposed LEA design reflects new costs that were not previously included in the LEA model—most notably, the Company's estimated costs of compliance with future Oregon GHG obligations. As a result, the output from the new LEA model results in a greater allowance for lower usage customers. This is by design, and specifically responds to the Commission's direction in Order No. 22-388.

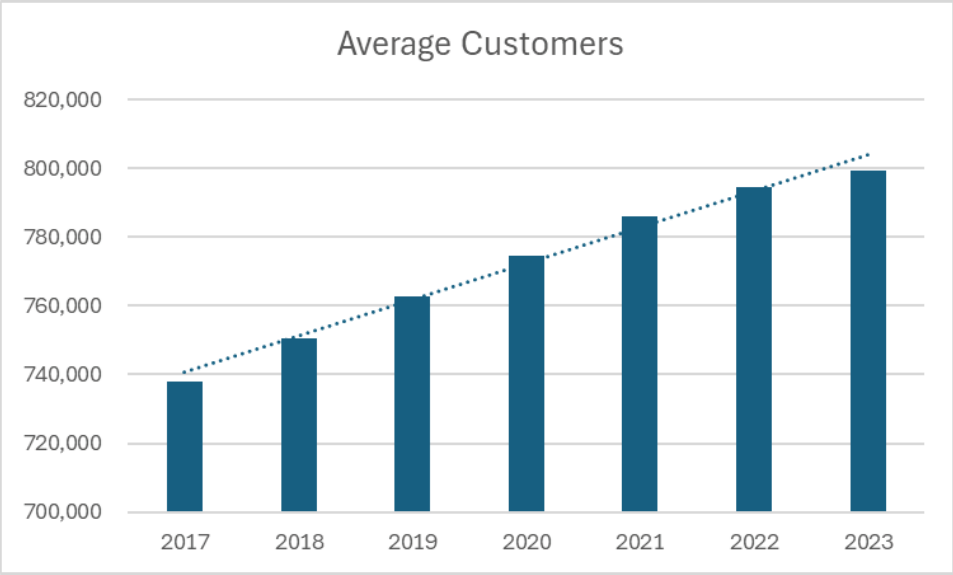
Instead of recognizing the benefits associated with incentivizing lower usage on the Company's system, CUB applies an overly pessimistic lens and claims that this result suggests that natural gas service will not be competitive with electric service. This is contrary to NW Natural's current experience regarding growth on the Company's system.

Q. Please describe the Company's recent experience regarding customer growth and customer choice between natural gas service and all electric homes.

A. As shown in Figure 1, below, NW Natural has continued to experience customer growth in recent years, indicating that customers still value natural gas service and continue to choose natural gas service rather than all-electric homes.

[40] CUB/200, Garrett/14.

Figure 1: NW Natural Average Customer Counts 2014-2023[41]



CUB's argument ignores the reality of consumer choice. If a prospective home buyer prefers an all-electric home, then they will buy one. Over time, if such customer preference is widespread, builders will choose to build all-electric homes in favor of homes that offer natural gas. Currently, this is not the case, as NW Natural's customer base continues to grow.

Q. In asserting that natural gas may be uncompetitive with electric service, did CUB present any analysis of future cost increases for electric service?

A. No. CUB's argument appears to be one-sided, in that it only focuses on the cost of natural gas. It is true that the LEA reflects additional costs that do not exist today for decarbonization via the cost assumptions for future Oregon GHG compliance obligations. However, CUB's argument entirely ignores the fact that

[41] Company SEC Form 10-K reports.

there will likely also be cost increases for electric service as electric utilities increase investment to meet growing customer demand and other costs to achieve their own ambitious decarbonization targets. For example, in Portland General Electric's ("PGE") most recent IRP, the Western Electricity Coordinating Council ("WECC") forecasts large increases in electric generation capacity needs in the next 20 years: "The WECC capacity will nearly double the current level by 2043…"[42]. The failure to acknowledge potential electric cost increases is disingenuous, particularly in view of CUB's vocal criticism of the electric utility rate increases in PGE's recently filed rate case.[43]

As detailed in the testimony of Company Witness Kravitz,[44] NW Natural recognizes that its customers have a choice in selecting natural gas in the first instance, and in remaining on the Company's system once they are customers. Over the years, natural gas service has been a reliable and cost-effective choice for consumers. Although the costs of decarbonization may put additional cost pressures on energy providers, NW Natural expects to continue to remain cost-competitive with electric service into the future.

[42] *In the Matter of Portland General Electric Company, 2023 Clean Energy Plan and Integrated Resource Plan,* Docket No. LC 80, PGE Clean Energy Plan and Integrated Resource Plan 2023 (filed March 31, 2023), p. 79.

[43] *In the Matter of Portland General. Elec. Co., Request for a General Rate Revision*, Docket No. UE 435, Oregon Citizens' Utility Board's Motion to Dismiss or Segregate Certain Issues (Mar. 14, 2024).

[44] NW Natural/2200, Kravitz/37.

Q. Did CUB present any studies or analysis in support of its claim that natural gas is becoming less cost-competitive?

A. No. As detailed in CUB's response to NW Natural DR 2, CUB's statement is based on "the implication of the Company's LEA policy design, not on any external analysis."[45]

Q. Please address CUB Witness Garrett's assertion that "the ideal NW Natural customer hooks up to the system but uses little to no therms of gas."[46]

A. CUB is partially correct—it is fair to say that more efficient customers will receive a higher LEA, and less efficient customers will receive a lower LEA. Notably, however, the slope of the allowance (large allowance for smaller customers to smaller allowances for larger users) is fairly flat yet is a stark contrast from historical LEAs that reward larger users with larger LEAs. This proposed LEA construct is intentional – and financially rewards new customers that are more efficient and generate less emissions.

The primary driver in the new LEA DCF calculation compared to the existing calculation is the inclusion of Proxy CPP costs and a higher fixed charge. The inclusion of Proxy CPP costs sends a clear signal to prospective customers that more efficient appliances and lower emissions are rewarded with a higher LEA. The higher monthly customer charge is designed to address the growing disparity

[45] NW Natural/4001, Therrien.

[46] CUB/200, Garrett/11.

in gas use between the Company's existing customer base and new customers, and to ensure that existing customers do not subsidize new customers.

NW Natural's vision for the future includes customer growth but also contemplates that customers will become more efficient in their gas usage, through both high efficiency and low usage appliances. The LEA and monthly customer charge proposals send the right price signals to achieve this outcome.

Q. Please address CUB Witness Garrett's complaint that "the focus of the LEA design is on lower use appliances and not high efficiency appliances."[47]

A. A portion of CUB Witness Garrett's argument is that lower usage appliances underutilize the gas system and leads to gas being uncompetitive. I find this argument unsupported and completely unpersuasive. Based on Company Witness Wyman's analysis,[48] the expected use per customer for a new customer is approximately 450 therms per year. The Company is clearly still anticipating new customers to join the system with high efficiency appliances, and likely in more weatherized buildings in new construction. However, given the growing recognition of the resiliency benefits of the gas system, the Company can also expect low-use customers to join the system and the tiered LEA design provides an option for this without sacrificing the economically-driven model.

[47] CUB/200, Garrett/14.

[48] NW Natural/1800, Wyman/24.

Q. CUB Witness Garrett also argues that the LEA as designed could incentivize hybrid heating systems ("backup to heat pump") but otherwise questions whether it is the right policy choice.[49] Please respond.

A. NW Natural—like its peer local distribution companies ("LDCs")—is in a transformational moment. As discussed throughout this testimony, the novel LEA design the Company has proposed accounts for future Oregon GHG regulations and charts a course for the acquisition of lower usage customers in the future. It is precisely the right policy choice for the moment.

Q. Please address CUB's claim that the LEA maximally incentivizes low usage luxury appliances that do not reliably tie a customer to the system for long enough to recover the cost of the LEA.[50]

A. Not all low-use natural gas appliances are "luxury" items. In fact, during periods of electric outages, perceived "luxury" items - such as natural gas ranges and fireplaces – become essential. CUB's phrasing blurs the line between "luxury" and simple consumer preferences. .

B. Reply to CUB's LEA Model Critiques

Q. Please summarize CUB's testimony addressing the assumptions in the LEA model.

A. CUB asserts that the LEA model is very complex; that NW Natural should continue to model carbon costs based on the invalidated CPP rather than a proxy; that the

[49] CUB/200, Garrett/14.

[50] CUB/200, Garrett/14.

model assumptions for benefits flowing from new customers are too high; that the new premises customer charge is too high and will cause customers to leave the system; and that the LEA model includes rate increases that will cause customer rates to sharply increase, resulting in customers leaving the system before the break-even point for cost recovery for the LEA, potentially creating stranded assets.[51]

Q. CUB Witness Garrett characterizes the proposed LEA model as "very complex."[52] Do you agree?

A. No, I do not. First, the proposed LEA model is a simple DCF model that uses cash inflows and cash outflows to derive an NPV. If the NPV is positive, then the investment is justified. In the LEA I modeled the maximum amount of investment (cash outflow) that can be supported by the projected cash inflows (revenues and cost avoidances). This maximum investment is the calculated LEA amount at various usage levels. This is not a complicated concept.

Admittedly, the LEA model has more inputs than the prior LEA model, however, this was the necessary result of addressing the Commission's direction in Order No. 22-388.

[51] CUB/200, Garrett/16-17.

[52] CUB/200, Garrett/16.

Q. CUB Witness Garrett asserts "the new benefits were modeled too high."[53] How do you respond?

A. I disagree entirely. The new customer benefits (cash inflows) are modeled accurately and conservatively. I used the proposed new customer tariff values provided by the Company. I used the Company's proposed non-growth capital expenditure forecast from its latest internal Company plan. The forecasted revenues from a new Oregon GHG compliance cost rider matches the expected new customer cost of compliance. The marginal cost of CPP Compliance (RNG) was provided by the Company and has more conservative cost estimates than what was included in the IRP and have been further revised to be even more conservative. There is no basis for CUB Witness Garrett's assertion that these cash inflows are modeled "too high."

Q. CUB Witness Garrett further speculates that the LEA model includes anticipated rate increases for residential customers, and that gas rates will sharply increase.[54] How do you respond?

A. The primary rate change assumption is the Company's proposed new customer Schedule 2 monthly fixed charge. Otherwise, rates are based on the proposed Schedule 2 rates and are held constant (real dollars) throughout the DCF analysis period. Other modeled changes reflect "The company's best reasonable estimate of present and future CPP compliance costs"[55] as shown in NW Natural/4006,

[53] CUB/200, Garrett/16.

[54] CUB/200, Garrett/16.

[55] Order No. 22-388, p. 52.

Therrien. Additionally, the Commission directives also include a requirement to show "the costs and benefits expected in other years, and a demonstration of when rate-based investments for customer additions covered by the LEA are depreciated and removed."[56] The initial construction cost investment is modeled in year 0 of the DCF calculation, and the impact of existing system (non-growth rate base investments and the depreciation of existing rate base over time) are also included in the DCF model,[57] and explained in detail in my Direct Testimony.[58] The anticipated non-growth rate base investments (net of depreciation of existing plant) would be expected with capital intensive industries like utilities (gas or electric). The dollars (including rates) are expressed in real terms, and do not include any "sharp increases."

Q. CUB suggests that the "skyrocketing" gas rates will drive customers from the system, potentially resulting in stranded LEAs.[59] Did CUB raise this argument in the last rate case, docket UG 435?

A. Yes. In Opening Testimony in docket UG 435, CUB recommended gradually phasing out the Company's LEA, and similarly predicted increasing costs, declining customer base, and stranded assets.[60]

[56] Order No. 22-388, p. 52

[57] NW Natural/4004, Therrien.

[58] NW Natural/1900, Therrien.

[59] CUB/200, Garrett/17.

[60] Docket No. UG 435, CUB's Opening Testimony, CUB/100, Jenks/13-17.

Q. Are CUB's predictions of customers leaving the system consistent with NW Natural's recent experience?

A. No, CUB's arguments in the last case and again here are based on pure speculation and are contrary to the Company's recent experience. CUB observes "the Company's declining number of new service connections since 2017, which have especially declined in recent years."[61] It appears that CUB is indicating here that the Company's *rate of growth* is slowing. However, CUB Witness Garrett does not provide any evidence that the Company's customer counts are declining. In fact, they are growing steadily, as shown in Figure 1, above.

Q. Are there other factors that may inform customer growth trends?

A. Yes. The Company's year-over-year rate of growth is influenced by several factors, including economic factors such as new housing starts. Simply put, if there are fewer new homes being built, NW Natural also sees less customer growth.

Q. CUB Witness Garrett argues that the increasing costs modeled in the LEA will drive customers to leave the system, resulting in stranded assets.[62] Do you agree?

A. No, I do not. Again, I believe CUB's view of the future is overly pessimistic and untethered to current conditions. As detailed above, the Company is not currently experiencing customers abandoning natural gas service, and NW Natural continues to expect customer growth into the future. There are no indications that

[61] CUB/200, Garrett/19.

[62] CUB/200, Garrett/22-24.

NW Natural is not a going concern, or that the physical delivery system will be materially different in the near future. Although the Company has indicated that it anticipates system usage and utilization to change in response to policy initiatives, it does not concede or foresee its business closing – quite the opposite – as new customer additions and existing customer preferences for natural gas remain strong.

Q. To CUB's point that a customer could leave the system early, in advance of the 25-year term of the LEA, would you agree that is a possible outcome?

A. Yes, it is possible that a new customer connection may be underutilized or abandoned before its full costs are recovered. However, it is equally possible that customers will remain on the system longer than 25 years, such that the benefits from the new customers accruing to the system would exceed the cost of the LEA. The new customers may actually over-contribute to its required LEA if: 1) their expected revenues exceed that needed to meet a zero NPV requirement, or 2) if the new customers (premises) remain active beyond 25 years.

Q. CUB also questions the new premises customer charge that is integrated into the LEA model and asserts that the Company's economic justification for the LEA rests in part on new premises customers being willing to pay ~50 percent more per therm than existing customers.[63] Is this correct?

A. No. The new premises customer charge is designed to ensure new premises customers pay their full cost of service and are not subsidized by the Company's

[63] CUB/200, Garrett/18.

existing customers. Thus, the new premises customer charge is higher than the customer charge for existing customers. The per therm rate is the same for both existing customers and new premises customers. This issue is addressed in detail in the Reply Testimony of Robert J. Wyman (NW Natural/3900, Wyman).

Q. CUB Witness Garrett asserts that the Company's economic justification rests in part on an assumption that new customers will not terminate service before the "60-year useful life of the LEA is up."[64] Is this correct?

A. No. It appears that CUB Witness Garrett confuses depreciable lives (60 years stated for a natural gas service) with the discounted payback of an LEA (proposed at 25 years).

In the event that the new premises LEA is based on 25 years and there is service (and billing) to the premises for 25 years, then the allowance, or Company investment, is fully paid for, regardless of the book depreciation rate used by the Company. The DCF calculation does not rely on a specified depreciation rate, but instead ensures a full recovery of investment as well as recovery on investment over the term. If the book depreciation rate used by the Company is based on a longer term, it means that the book return during the DCF term is actually higher than required, which benefits the Company and existing customers depending on rate case timing during the period. If the new premises then discontinues service after the assumed 25 years, there may be a remaining level of book investment,

[64] CUB/200, Garrett/18.

but the cost of service on that amount is equal to the over-recovery provided earlier.

Q. CUB also calculated the estimated cost to customers associated with the stranded assets, assuming two different scenarios—the first assuming a 1 percent attrition rate for new customers, resulting in stranded assets of about $43 million, and the second assuming that half of the "new premises" customers that received an LEA in 2025 terminated NW Natural service in 15 years, which is about the time their gas furnace would be replaced, and calculating the net cost of stranded assets for existing customers to be $36 - $44 million.[65] What is your response to CUB's analysis?

A. As an initial matter, there is no evidence that support the premise underlying CUB's scenarios that customers will be leaving the Company's system. Rather, as shown in Figure 1 above, new customer additions remain strong and total customer counts are growing – not shrinking.

Regarding CUB's first scenario, the estimated 1 percent attrition rate is not backed by any historical attrition data, but instead appears to be figure chosen at random.

Regarding CUB's second scenario, CUB assumes that customers will leave the system after the 15-year life of their appliance has ended. Again, CUB's assumption here is based on speculation and a pessimistic view of the future of the natural gas system. Based on my industry experience I believe that it is equally

[65] CUB/200, Garrett/12.

likely that customers will instead continue the pattern of behavior that natural gas companies have seen historically, which is to replace their end-of-life natural gas appliances with newer and more efficient natural gas appliances.

Q. Have you identified any other shortcomings in CUB Witness Garrett's stranded asset scenarios?

A. Yes, I have. As discussed above, CUB Witness Garrett confuses the depreciable life of an asset (e.g., service line 60-year life) with the 25-year DCF analysis. Costs are not stranded if they have been paid for. The fact that there is a timing difference between cost recovery (proved through the LEA DCF analysis) and depreciation (used for general rate-making) does not mean there are stranded costs.

C. Reply to CUB's Recommendation

Q. What is CUB's recommendation?

A. CUB asserts that incentivizing growth of the gas system at this time poses unacceptable risks to existing customers, and NW Natural's LEA should, alongside Avista's LEA, be phased down to $0.00.[66]

Q. How do you respond?

A. Based on my point-by-point rebuttal of CUB Witness Garrett's assertions above, I recommend that the Commission adopt the Company's new LEA proposal. There is no compelling evidence presented by CUB Witness Garrett that warrants an elimination of the LEA. The Company's modified proposal addresses Commission

[66] CUB/200, Garrett/12.

concerns and supports the state's emission reduction goals through a pricing incentive to new customers to install high-efficiency/low use appliances. The revised LEA also supports a transition to a hybrid heating solution whereby the resiliency offered by the natural gas delivery system is retained.

V. REPLY TO COALITION INTERVENORS

Q. Please summarize Coalition Witness Cebulko's Opening Testimony.

A. Coalition Witness Cebulko's arguments are rooted in speculation about the future of gas in the U.S. and Oregon. Similar to CUB, he also relies on unsupported arguments that natural gas is, and will become, uncompetitive with electricity. Coalition Witness Cebulko also claims that continuing the LEA will lead to stranded costs. Lastly, in my opinion, the Coalition appears to misunderstand the financial mechanics of LEAs that underpin jurisdictional approaches across the country. To summarize, Coalition Witness Cebulko, and through Coalition Co-witnesses Apter and Connolly, seek to use the LEA proposal as a platform for public policy arguments and fail to quantitatively support any of their arguments.

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A. Reply to Coalition Regarding Policy and Market Trends

Q. Coalition Witness Cebulko asserts that following the invalidation of the CPP, it is anticipated that ODEQ will promulgate new rules with an enforceable declining cap, and that there is a high likelihood that the Company will face similarly strict emissions reduction mandates to the invalidated CPP.[67] Coalition Witness Cebulko further claims that the Company does not have a reasonable plan for achieving emissions reductions while maintaining or expanding its current distribution system, such that the LEA is directionally inconsistent with the state's future CPP policy.[68] How do you respond?

A. As I have noted in my responses to Staff and CUB, I disagree that the LEA is directionally inconsistent with the state's energy policy. To the contrary, the LEA is designed to help ensure responsible growth on the Company's system in the years to come.

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[67] Coalition/100, Cebulko/9.
[68] Coalition/100, Cebulko/9.

Q. Coalition Witness Cebulko comments that market shifts are occurring, such that electric appliances are cost competitive with natural gas appliances, relying upon a Sierra Club commissioned report from Synapse Energy Economics, Inc.[69] Have you reviewed this report, and what conclusions do you draw from it?

A. I have reviewed this report, and in my opinion, it contains some aggressive and unrealistic assumptions regarding customer adoption of electric equipment over the next 11 years (to achieve 2035 State of Oregon emission targets) and the following 15 years (to achieve 2050 emissions goals). For example, the Synapse Report establishes two pathways for full electrification (the "2025 Sales Target" and the "2030 Sales Target"). In these examples Synapse shows a chart depicting the necessary sales conversions to electric heat pumps, as shown below in Figure 3:

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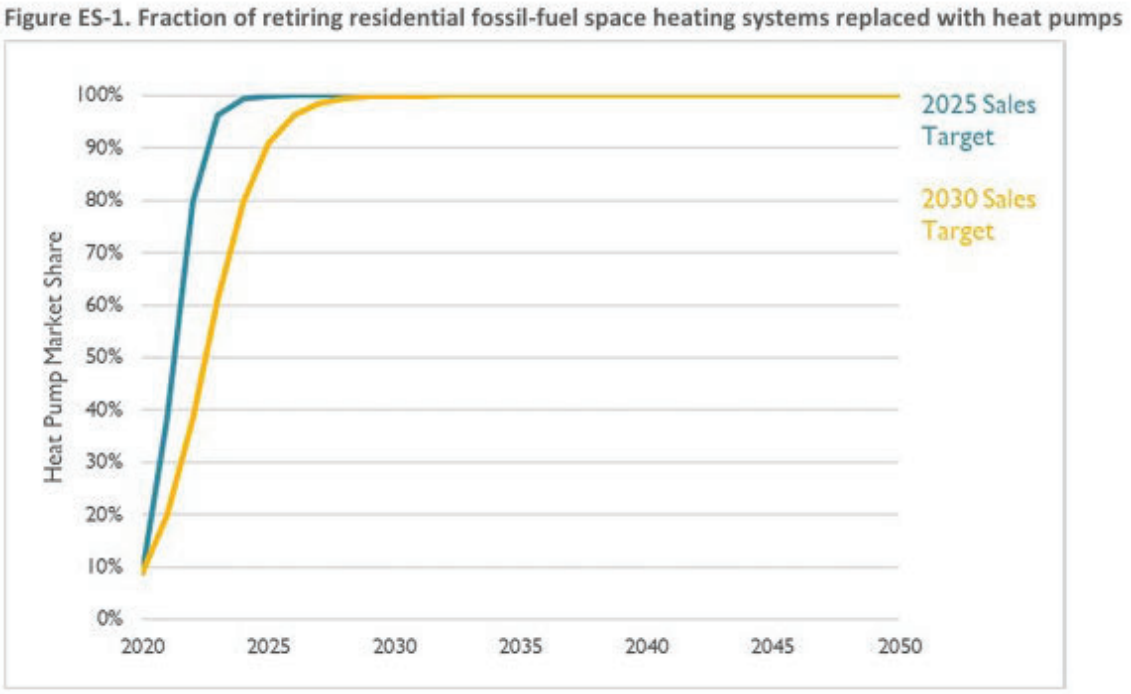
[69] Coalition/100, Cebulko/10. "Toward Net Zero Emissions from Oregon Buildings: Emissions and Cost Analysis of Efficient Electrification Scenarios", prepared for Sierra Club, June 23, 2022 (herein referred to as the "Synapse Report").

Figure 3: Synapse Report Figure ES-1
(reproduced from Synapse Report page ii)



The Synapse Report describes these sales targets ("adoption curves") as "steep", and that "[t]he sales of efficient electrical equipment such as heat pumps have to ramp up very quickly for Oregon to meet its emissions reduction goals."[70] Generally, the Synapse Report is tailored to its client's perspective and, in my opinion, does not represent an independent objective perspective on the future of NW Natural's long-term business prospects. For example, the Synapse Report states: "[i]t is important to note that our payback analysis does not include various other factors that could affect customers' purchase decisions, such as potential electrical panel upgrade costs, future changes in electric and gas prices, and

[70] Synapse Report executive summary page i.

qualitative customer preference factors."[71] Statements and qualifications such as these undermine the conclusions in the report and lead me to conclude that relying on the Synapse Report for rejecting the proposed LEA is misplaced.

Q. Coalition Witness Cebulko also claims that eliminating the LEA will align with Avista's agreement to phase out its LEA in Oregon, as well as recent changes in LEA policy in California, Massachusetts, and Connecticut.[72] How do you respond?

A. I have addressed the issue of other gas LDCs in Washington State, including Avista, which has a portion of their service territory in Oregon. The elimination of Avista's LEA is a product of settlement, whereby many issues, including the overall revenue requirement determination, were settled. It is not the product of a Commission order in a fully-litigated case.

Regarding Massachusetts, the Massachusetts Department of Public Utilities "MDPU") issued its Order No. 20-80-B, but does not eliminate LEAs. Rather, this Order is "a regulatory strategy for pursuing an energy future that begins to move the Commonwealth beyond gas and toward its climate objectives."[73] In reading this order it is clear that the state of Massachusetts is in the process of reviewing all gas activities in the broader context of state climate objectives. At present, there is no stated timeframe for specific evaluation of LEAs.

[71] Synapse Report executive summary page vi.

[72] Coalition/100, Cebulko/20.

[73] Massachusetts D.P.U. 20-80-B page 137.

Similarly, Connecticut has not eliminated LEAs. In its April 22, 2022 Order[74] to evaluate the state's natural gas expansion plan, the Connecticut Public Utilities Regulatory Authority ("PURA") "winded down" its gas expansion plan. As part of this cessation of the expansion plan, certain incentives associated with the plan were modified or terminated. With regard to LEAs, PURA reverted its LEA policy back to pre-expansion terms, but did not ban new customer additions.

B. Reply to the Coalition's Model Critiques

Q. Coalition Witness Cebulko states that "the Company's proposed LEA methodology suffers from several significant, problematic assumptions."[75] Do you agree?

A. No, I do not. First, Coalition Witness Cebulko seems to confuse the issue by implying that the Company is changing its LEA calculation methodology from a "times margin" approach to a DCF approach. What Coalition Witness Cebulko fails to acknowledge is that these methodologies are one in the same. The DCF calculation is run to ensure that the expected revenues will result in a positive NPV, and to determine a reasonable times margin factor. The Company's proposed tiered LEA is based on a DCF model approach as shown in my Direct Testimony exhibits. Both approaches rely on the same classic financial methodology of net present value of discounted cash flows. While the approaches express the LEA in

[74] Docket No. 21-08-24: Petition Of William Tong, Attorney General for the State of Connecticut, and the Office of Consumer Counsel for an Investigation Into Eversource Energy Regarding Gas Expansion Marketing.

[75] Coalition/100, Cebulko/18.

different forms (a revenue multiplier and a fixed allowance), both forms are underpinned by a DCF approach.

Q. Why did the Company propose a fixed dollar LEA instead of continuing with a times margin LEA?

A. The proposed fixed dollar LEA (based on usage tiers) now includes additional costs and offsets not included in distribution-only revenues. This change in calculation components is in direct response to the Commission's directives in Order No. 22-388. Expressing LEA on a times margin basis is not consistent with these additional requirements, thus using the DCF methodology to calculate fixed LEA dollar amounts at proposed usage tiers is preferrable and more instinctive compared to carrying forward an LEA expressed on a times margin basis.

Q. Does Coalition Witness Cebulko identify other concerns with the proposed LEA methodology?

A. Yes, Coalition Witness Cebulko identifies six perceived shortcomings in the proposed LEA calculation.[76] Of these concerns I have addressed all of them in response to Staff Witness Dlouhy's and CUB Witness Garrett's Opening Testimony above, except for the assumed operations and maintenance ("O&M") assumption. For clarity, the O&M included in the DCF calculation is incremental. I have assumed that this incremental O&M remains constant over the 25-year LEA DCF analysis because the DCF calculation as a whole is expressed in real dollar terms, meaning it excludes the impact of inflation. Base distribution rates, which

[76] Coalition/100, Cebulko/27.

generate the revenues used in the DCF calculation, are held constant for the 25-year term. These revenues reflect a revenue requirement inclusive of O&M. I did not assume that, over the 25-year term of the DCF analysis, O&M would increase at a greater rate than allowed rates. I have no reason to believe otherwise. As a parallel, I have no reason to believe other components of incremental LEA revenue requirement, such as property taxes or income taxes, would materially differ from that included in base rates in real dollar terms.

Q. Please respond to Coalition Witness Cebulko's assertion that the proposed LEA is "directionally absurd."[77]

A. Coalition Witness Cebulko is comparing a recalculated LEA with new assumptions and requirements from the Commission Order to an artificial cap value. Absent the cap, the comparison would be much closer.

Q. Coalition Witness Cebulko further asserts that "the Company's program is the riskiest structure imaginable for existing customers."[78] Please respond.

A. The LEA model proposed herein is based on a fundamental, long-standing analysis using a common DCF approach. The results of the model reflect the expected cash flows from a new customer connection and will pay for itself, on an NPV basis, in twenty-five years. The size of the proposed LEA is the product of this calculation. It is no more risky than previously calculated LEAs or any riskier

[77] Coalition/100, Cebulko/25.

[78] Coalition/100, Cebulko/26.

than the vast majority of LEAs around the country. I respectfully suggest the Commission ignore such sensationalism from Coalition Witness Cebulko.

C. Reply to the Coalition's Recommendation

Q. The Coalition asserts the Commission should eliminate the Company's residential and non-residential LEAs, on the basis that the policy is no longer in the public interest and exposes customers to economic risk, is counterproductive for meeting the state's emissions reduction goals, and increases the costs and risks for existing customers.[79] How do you respond?

A. For the reasons described in my point-by-point rebuttal above, I recommend the Commission approve the Company's modified LEA, which accurately and fairly reflects the Commission's directives from Order No. 22-388. The proposed LEA does not expose (existing) customers to any incremental economic risk compared to past LEA calculations. The model incorporates the proxy CPP compliance costs consistent with the Commission's directives and is therefore not counter-productive for meeting the state's emission reduction goals. Rather, the LEA alignment that now favors more efficient gas usage (through a higher LEA at lower usage levels) advances the state's emission reduction goals. Lastly, the mathematical calculation of the DCF methodology reasonably ensures that new customers pay (at least) their fair share and do not result in increased costs to existing customers.

[79] Coalition/100, Cebulko/18-19.

VI. CONCLUSION AND RECOMMENDATION

Q. What is your recommendation regarding NW Natural's proposed LEA?

A. I recommend the modest changes to the revised DCF calculation described above, and reject all other recommendations made by Staff Witness Dlouhy, CUB Witness Garrett and the Coalition Intervenors.

Q. Does this conclude your Reply Testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibits of Gregg H. Therrien

LINE EXTENSION ALLOWANCE
EXHIBITS 4001 – 4008

June 4, 2024

EXHIBITS 4001-4008 – LINE EXTENSION ALLOWANCE

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Gregg H. Therrien

LINE EXTENSION ALLOWANCE
EXHIBIT 4001

June 4, 2024

Exhibit NW Natural 4001

Oregon Citizens' Utility Board
610 SW Broadway, Suite 400
Portland, OR 97205
(503) 227-1984
www.oregoncub.org

May 13, 2024

TO: NW Natural (NWN)

FROM: Oregon Citizens' Utility Board (CUB)

RE: UG 490 NWN DRs 2-6 to CUB

UG 490
CUB Response to NWN Data Request Nos. 2-6
Date: May 13, 2024

Data Request 2:

Referring to CUB/200, Garrett/10, Line 20 through /11, Line 3, specifically: "The Company's LEA design implies that the product the Company delivers is becoming less cost-competitive, and that the ideal NW Natural customer hooks up to the system but uses little to no therms of gas." Please provide all analyses, workpapers (with formulae intact), studies, reports or other documents that CUB relied upon to make this statement.

Data Response 2:

CUB's statement was based on the implication of the Company's LEA policy design, not on any external analysis.

Data Request 3:

Referring to CUB/200, Garrett/11, Lines 9-12, specifically: "Over the 25-year LEA repayment period in the Company's modeling, the customer charge alone will cost the "new premise" new customer $7,875, meaning the new customer could save $7,875 by discontinuing gas service." Please provide all analyses, workpapers, studies, reports or other documents that CUB relied upon to conclude that a new customer could save money by discontinuing gas service compared with the cost of an alternative electric utility provider.

Data Response 3:

CUB's statement was a statement of mathematics. Over a 25-year period, $7,875 is the cost of NW Natural's "new premise" customer charge and a customer who does not buy gas service would not pay this charge.

Data Request 4:

Referring to CUB/200, Garrett/18, Lines 10-13, specifically: "CUB argues this assumption is unreasonable, and that a meaningful quantity of customers will notice the customer charge, calculate that it alone will cost them $315/yr ($26.25/ month x 12 months/yr), or $7,875 in 25 years, and terminate NW Natural service within 25 years."

a. Please provide all analyses, workpapers (with formulae intact), studies, reports or other documents that CUB relied upon to make this statement.
b. Based on this statement, what is the breakeven amount that would keep a "meaningful quantify" of customers connected after 25 years?

Data Response 4:

a. CUB calculated an approximate 51% rate increase for new customers through the "new premise" customer charge as demonstrated in Cub Exhibit 203 and as provided to the Company in Attachment C of CUB's response to NWN DR 1. Moreover, fundamental economic theory of price elasticity indicates that if you charge customers more and customers have other options (such as electricity, propane, solar, or wood for space heating), then some customers will react to that price signal.
b. CUB's customer attrition modeling covered a broad range of scenarios. See CUB/200, Garrett/26 – 27. CUB analyzed NWN's proposal and did not seek out alternative "breakeven amounts." CUB is uncertain what is meant by "breakeven amount" here.

Data Request 5:

Referring to CUB/200, Garrett/10, Line 4, specifically: "multifamily customers tend to be renters and/or lower income." Please produce CUB's analysis that supports this assertion, including all documents, workpapers, and Excel files with formulae intact, etc.
a. What is the share of low-income households that are in older (10+ years) multi-family housing compared to more newly constructed (10 years or less) housing?
b. What is the share of low-income households in multi-family housing that is individually metered for gas service compared to multi-family housing that is not individually metered for gas service?

Data Response 5:

CUB believes that the statement "Multifamily customers tend to be renters and/or lower income" is a factual statement. While there are owner-occupied condominiums that are considered multi-family housing, CUB believes that it is an accurate statement to say that most multi-family housing supports renters. In addition, there is a great deal of data that demonstrates that renters have lower incomes than homeowners (*see* Portland Demographics and Housing Stock, published by the City of Portland,

https://www.portland.gov/phb/documents/2022-state-housing-part-1-portland-demographics-and-housing-stock/download).

a. CUB has not attempted to quantify the share of low-income households that are in older (10+ years) multi-family housing compared to more newly constructed (10 years or less) housing.
b. CUB has not attempted to quantify the share of low-income households in multi-family housing that is individually metered for gas service compared to multi-family housing that is not individually metered for gas service.

Data Request 6:

Referring to CUB/100, Jenks/7-18, specifically CUB's Rate Shock Standard Proposal.

a. Please describe with specificity what rate changes (e.g. rate case, WACOG, RNG AAC, decoupling deferral, Bill Discount Program) would be subject to CUB's Rate Shock Standard Proposal.

b. How would non-November 1st rate changes be calculated for purposes of determining rate shock? Please provide an example calculation.

c. Please state whether rate increases associated with the reestablished CPP rules are proposed to be included in the rate shock mechanism. Please explain.

d. Please provide: (i) all customer rate impact analyses developed by CUB for the invalidated CPP or any reestablished CPP rules; and (ii) all customer rate impact analyses developed by a third-party that are in the custody of CUB for the invalidated CPP or any reestablished CPP rules.

e. Which version of the Consumer Price Index is CUB proposing to use (e.g., U.S. All Urban CPI, West Region Urban CPI)?

Data Response 6:

a. CUB's proposal would apply to all adjustments that occur on November 1.
b. The rate shock proposal for gas companies is focused on the November 1 rate change. At this time, CUB has not proposed including non-November 1 rate changes for gas utilities. Because CUB is primarily concerned about winter bill impacts, moving some of the rate filing to December 1 or January 1 would not solve the winter rate shock problem and would likely cause CUB to amend our proposal to include the full winter season.
c. Yes, if they occur on Nov. 1
d. The Rate impact analysis of the CPP has been presented in the DEQ's CPP rulemaking and in utility IRPs. CUB did not develop additional CPP rate impact analysis in preparing its testimony.
e. CUB did not propose a specific version of the CPI.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Gregg H. Therrien

LINE EXTENSION ALLOWANCE
EXHIBIT 4002

June 4, 2024

NW Natural
Exhibit NW Natural/4002R, Therrien - DCF Summary Example

			Year 1	Year 2	Year 3	Year 4	Year 5
1	Revenue from New Connection Tariff	*Exh 4005*	1,221	1,221	1,221	1,221	1,221
2	Proxy CPP Revenue	*Exh 4006*	28	41	358	397	489
3	Proxy CPP Cost	*Exh 4006*	(335)	(335)	(2,200)	(2,200)	(2,200)
4	Nominal Change in Base Rate Revenue per Customer	*Exh 4003*	0	(14)	(27)	(41)	(54)
5	Contribution to New Non-Growth Capex	*Exh 4004*	34	82	122	158	193
6	Operations & Maintenance		(79)	(79)	(79)	(79)	(79)
7	Franchise Tax	2.74%	(33)	(33)	(33)	(33)	(33)
8	Property Tax	1.50%	(25)	(24)	(23)	(22)	(21)
9	Net Before Taxes		811	859	(661)	(599)	(485)
10	Income Tax	27.00%	219	232	(179)	(162)	(131)
11	Net After Tax		592	627	(483)	(437)	(354)
12	Tax Benefit on Investment		17	32	30	28	26
13	Total Operating Cash (ROR Analysis)	($1,664)	609	660	(453)	(409)	(328)

		Rate	Year 1	Year 2	Year 3	Year 4	Year 5
1	Plant		1,664	1,664	1,664	1,664	1,664
2	Depreciation (per model term)	4.000%	(67)	(133)	(200)	(266)	(333)
3	Net Plant		1,597	1,531	1,464	1,398	1,331
4	Deferred Taxes		(1)	13	25	35	43
5	Net Rate Base		1,599	1,518	1,439	1,363	1,288
6	Average Rate Base		1,631	1,558	1,478	1,401	1,326
	Basis for interest expense		816	779	739	700	663

Tax Depreciation			Year 1	Year 2	Year 3	Year 4	Year 5
1	Tax Depreciation Rate		3.75%	7.22%	6.68%	6.18%	5.71%
2	Plant Additions		1,664				
3	Total Tax Depreciation		62	120	111	103	95
4	Tax Benefit @	27.00%	17	32	30	28	26

Book Depreciation							
1	Book Depreciation Rate		4.00%	4.00%	4.00%	4.00%	4.00%
2	Plant Additions		1,664				
3	Book Depreciation		67	67	67	67	67
4	Total Book Depreciation		67	67	67	67	67
5	Total Tax Depreciation		62	120	111	103	95
6	Difference		(4)	54	45	36	29
7	Deferred Taxes	27.00%	(1)	14	12	10	8
	20 year MACRS		3.75%	7.22%	6.68%	6.18%	5.71%

			Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
1	Revenue from New Connection Tariff	*Exh 4005*	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221
2	Proxy CPP Revenue	*Exh 4006*	581	640	746	854	965	1,079	1,160	1,243	1,327	1,413
3	Proxy CPP Cost	*Exh 4006*	(2,200)	(2,200)	(2,230)	(2,260)	(2,290)	(2,320)	(2,350)	(2,380)	(2,410)	(2,440)
4	Nominal Change in Base Rate Revenue per Customer	*Exh 4003*	(68)	(81)	(95)	(109)	(122)	(136)	(149)	(163)	(176)	(190)
5	Contribution to New Non-Growth Capex	*Exh 4004*	223	254	286	316	345	373	399	424	448	471
6	Operations & Maintenance		(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)
7	Franchise Tax	2.74%	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)
8	Property Tax	1.50%	(20)	(19)	(18)	(17)	(16)	(15)	(14)	(13)	(12)	(11)
9	Net Before Taxes		(375)	(297)	(202)	(106)	(9)	90	155	220	286	352
10	Income Tax	27.00%	(101)	(80)	(55)	(29)	(2)	24	42	59	77	95
11	Net After Tax		(274)	(217)	(148)	(78)	(7)	65	113	160	208	257
12	Tax Benefit on Investment		24	22	20	20	20	20	20	20	20	20
13	Total Operating Cash (ROR Analysis)	($1,664)	(250)	(195)	(127)	(58)	13	86	133	180	228	277

		Rate	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
1	Plant		1,664	1,664	1,664	1,664	1,664	1,664	1,664	1,664	1,664	1,664
2	Depreciation (per model term)	4.000%	(399)	(466)	(532)	(599)	(666)	(732)	(799)	(865)	(932)	(998)
3	Net Plant		1,265	1,198	1,132	1,065	998	932	865	799	732	666
4	Deferred Taxes		49	53	55	57	59	61	63	65	67	69
5	Net Rate Base		1,216	1,145	1,077	1,008	939	871	802	733	665	596
6	Average Rate Base		1,252	1,181	1,111	1,042	974	905	836	768	699	630
	Basis for interest expense		626	590	556	521	487	452	418	384	350	315

Tax Depreciation			Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
1	Tax Depreciation Rate		5.29%	4.89%	4.52%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%
2	Plant Additions											
3	Total Tax Depreciation		88	81	75	74	74	74	74	74	74	74
4	Tax Benefit @	27.00%	24	22	20	20	20	20	20	20	20	20

Book Depreciation												
1	Book Depreciation Rate		4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
2	Plant Additions											
3	Book Depreciation		67	67	67	67	67	67	67	67	67	67
4	Total Book Depreciation		67	67	67	67	67	67	67	67	67	67
5	Total Tax Depreciation		88	81	75	74	74	74	74	74	74	74
6	Difference		21	15	9	8	8	8	8	8	8	8
7	Deferred Taxes	27.00%	6	4	2	2	2	2	2	2	2	2
	20 year MACRS		5.29%	4.89%	4.52%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%

			Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25
1	Revenue from New Connection Tariff	*Exh 4005*	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221
2	Proxy CPP Revenue	*Exh 4006*	1,501	1,591	1,662	1,733	1,805	1,876	1,947	2,019	2,090	2,161
3	Proxy CPP Cost	*Exh 4006*	(2,470)	(2,500)	(2,500)	(2,500)	(2,500)	(2,500)	(2,500)	(2,500)	(2,500)	(2,500)
4	Nominal Change in Base Rate Revenue per Customer	*Exh 4003*	(204)	(217)	(231)	(244)	(258)	(271)	(285)	(298)	(312)	(326)
5	Contribution to New Non-Growth Capex	*Exh 4004*	492	512	531	549	565	581	596	610	624	638
6	Operations & Maintenance		(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)
7	Franchise Tax	2.74%	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)
8	Property Tax	1.50%	(10)	(9)	(8)	(7)	(6)	(5)	(4)	(3)	(2)	(1)
9	Net Before Taxes		418	486	563	640	715	789	863	936	1,009	1,081
10	Income Tax	27.00%	113	131	152	173	193	213	233	253	272	292
11	Net After Tax		305	354	411	467	522	576	630	683	736	789
12	Tax Benefit on Investment		20	20	20	20	20	10	0	0	0	0
13	Total Operating Cash (ROR Analysis)	($1,664)	326	375	431	487	542	586	630	683	736	789

		Rate	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25
1	Plant		1,664	1,664	1,664	1,664	1,664	1,664	1,664	1,664	1,664	1,664
2	Depreciation (per model term)	4.000%	(1,065)	(1,132)	(1,198)	(1,265)	(1,331)	(1,398)	(1,464)	(1,531)	(1,597)	(1,664)
3	Net Plant		599	532	466	399	333	266	200	133	67	0
4	Deferred Taxes		72	74	76	78	80	72	54	36	18	0
5	Net Rate Base		528	459	390	322	253	194	146	97	49	(0)
6	Average Rate Base		562	493	425	356	287	224	170	121	73	24
	Basis for interest expense		281	247	212	178	144	112	85	61	36	12

Tax Depreciation			Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25
1	Tax Depreciation Rate		4.46%	4.46%	4.46%	4.46%	4.46%	2.23%	0.00%	0.00%	0.00%	0.00%
2	Plant Additions											
3	Total Tax Depreciation		74	74	74	74	74	37	0	0	0	0
4	Tax Benefit @	27.00%	20	20	20	20	20	10	0	0	0	0

Book Depreciation												
1	Book Depreciation Rate		4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
2	Plant Additions											
3	Book Depreciation		67	67	67	67	67	67	67	67	67	67
4	Total Book Depreciation		67	67	67	67	67	67	67	67	67	67
5	Total Tax Depreciation		74	74	74	74	74	37	0	0	0	0
6	Difference		8	8	8	8	8	(29)	(67)	(67)	(67)	(67)
7	Deferred Taxes	27.00%	2	2	2	2	2	(8)	(18)	(18)	(18)	(18)
	20 year MACRS		4.46%	4.46%	4.46%	4.46%	4.46%	2.23%	0.00%	0.00%	0.00%	0.00%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Gregg H. Therrien

LINE EXTENSION ALLOWANCE
EXHIBIT 4003

June 4, 2024

NW Natural
Exhibit NW Natural/4003, Therrien - Existing System Revenue Requirements

	Description		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9
	Revenue Requirement Calculations										
1	Gross Plant		$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881
2	Accumulated Depreciation		$ (1,590,754,661)	$ (1,687,260,190)	$ (1,783,765,719)	$ (1,880,271,247)	$ (1,976,776,776)	$ (2,073,282,305)	$ (2,169,787,834)	$ (2,266,293,363)	$ (2,362,798,891)
3	Net Plant		$ 2,412,638,220	$ 2,316,132,691	$ 2,219,627,163	$ 2,123,121,634	$ 2,026,616,105	$ 1,930,110,576	$ 1,833,605,047	$ 1,737,099,519	$ 1,640,593,990
4	Deferred Taxes		$ (435,773,775)	$ (418,342,824)	$ (400,911,873)	$ (383,480,922)	$ (366,049,971)	$ (348,619,020)	$ (331,188,069)	$ (313,757,118)	$ (296,326,167)
5	Average Rate Base (Plant related)		$ 1,976,864,445	$ 1,897,789,867	$ 1,818,715,290	$ 1,739,640,712	$ 1,660,566,134	$ 1,581,491,556	$ 1,502,416,978	$ 1,423,342,401	$ 1,344,267,823
6	Pre-Tax ROR		9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%
7	Return and Taxes		$ 178,979,125	$ 171,819,960	$ 164,660,795	$ 157,501,630	$ 150,342,465	$ 143,183,300	$ 136,024,135	$ 128,864,970	$ 121,705,805
8	Book Depreciation		96,505,529	96,505,529	96,505,529	96,505,529	96,505,529	96,505,529	96,505,529	96,505,529	96,505,529
9	O&M		539,667,000	539,667,000	539,667,000	539,667,000	539,667,000	539,667,000	539,667,000	539,667,000	539,667,000
10	Property Taxes	1.5%	36,189,573	34,741,990	33,294,407	31,846,825	30,399,242	28,951,659	27,504,076	26,056,493	24,608,910
11	Franchise Tax and Comm Fees	2.7%	23,992,909	23,750,349	23,507,790	23,265,230	23,022,671	22,780,111	22,537,552	22,294,992	22,052,433
12	Annual Revenue Requirement		$ 875,334,136	$ 866,484,828	$ 857,635,521	$ 848,786,214	$ 839,936,906	$ 831,087,599	$ 822,238,291	$ 813,388,984	$ 804,539,676
13	No. of Customers		652,270	652,270	652,270	652,270	652,270	652,270	652,270	652,270	652,270
14	Existing Plant Revenue Requirement Per Customer		$ 1,341.98	$ 1,328.42	$ 1,314.85	$ 1,301.28	$ 1,287.71	$ 1,274.15	$ 1,260.58	$ 1,247.01	$ 1,233.45
15	YoY Change			$ (13.57)	$ (13.57)	$ (13.57)	$ (13.57)	$ (13.57)	$ (13.57)	$ (13.57)	$ (13.57)
16	Cumulative Change		$ -	$ (13.57)	$ (27.13)	$ (40.70)	$ (54.27)	$ (67.83)	$ (81.40)	$ (94.97)	$ (108.54)
17	Depreciation Expense (based on model term rate)	4.00%	$ 96,505,529	$ 96,505,529	$ 96,505,529	$ 96,505,529	$ 96,505,529	$ 96,505,529	$ 96,505,529	$ 96,505,529	$ 96,505,529
18	Deferred Tax Amortization (based on model term rate)		$ 17,430,951	$ 17,430,951	$ 17,430,951	$ 17,430,951	$ 17,430,951	$ 17,430,951	$ 17,430,951	$ 17,430,951	$ 17,430,951
19	Net Utility Plant		$ 1,964,464,000								

NW Natural
Exhibit NW Natural/4003, Therrien - Existing System Revenue Requirements

	Description	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19
	Revenue Requirement Calculations										
1	Gross Plant	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881
2	Accumulated Depreciation	$ (2,459,304,420)	$ (2,555,809,949)	$ (2,652,315,478)	$ (2,748,821,007)	$ (2,845,326,535)	$ (2,941,832,064)	$ (3,038,337,593)	$ (3,134,843,122)	$ (3,231,348,651)	$ (3,327,854,179)
3	Net Plant	$ 1,544,088,461	$ 1,447,582,932	$ 1,351,077,403	$ 1,254,571,874	$ 1,158,066,346	$ 1,061,560,817	$ 965,055,288	$ 868,549,759	$ 772,044,230	$ 675,538,702
4	Deferred Taxes	$ (278,895,216)	$ (261,464,265)	$ (244,033,314)	$ (226,602,363)	$ (209,171,412)	$ (191,740,461)	$ (174,309,510)	$ (156,878,559)	$ (139,447,608)	$ (122,016,657)
5	Average Rate Base (Plant related)	$ 1,265,193,245	$ 1,186,118,667	$ 1,107,044,089	$ 1,027,969,511	$ 948,894,934	$ 869,820,356	$ 790,745,778	$ 711,671,200	$ 632,596,622	$ 553,522,045
6	Pre-Tax ROR	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%
7	Return and Taxes	$ 114,546,640	$ 107,387,475	$ 100,228,310	$ 93,069,145	$ 85,909,980	$ 78,750,815	$ 71,591,650	$ 64,432,485	$ 57,273,320	$ 50,114,155
8	Book Depreciation	96,505,529	96,505,529	96,505,529	96,505,529	96,505,529	96,505,529	96,505,529	96,505,529	96,505,529	96,505,529
9	O&M	539,667,000	539,667,000	539,667,000	539,667,000	539,667,000	539,667,000	539,667,000	539,667,000	539,667,000	539,667,000
10	Property Taxes	23,161,327	21,713,744	20,266,161	18,818,578	17,370,995	15,923,412	14,475,829	13,028,246	11,580,663	10,133,081
11	Franchise Tax and Comm Fees	21,809,873	21,567,313	21,324,754	21,082,194	20,839,635	20,597,075	20,354,516	20,111,956	19,869,397	19,626,837
12	Annual Revenue Requirement	$ 795,690,369	$ 786,841,061	$ 777,991,754	$ 769,142,446	$ 760,293,139	$ 751,443,832	$ 742,594,524	$ 733,745,217	$ 724,895,909	$ 716,046,602
13	No. of Customers	652,270	652,270	652,270	652,270	652,270	652,270	652,270	652,270	652,270	652,270
14	Existing Plant Revenue Requirement Per Customer	$ 1,219.88	$ 1,206.31	$ 1,192.75	$ 1,179.18	$ 1,165.61	$ 1,152.04	$ 1,138.48	$ 1,124.91	$ 1,111.34	$ 1,097.78
15	YoY Change	$ (13.57)	$ (13.57)	$ (13.57)	$ (13.57)	$ (13.57)	$ (13.57)	$ (13.57)	$ (13.57)	$ (13.57)	$ (13.57)
16	Cumulative Change	$ (122.10)	$ (135.67)	$ (149.24)	$ (162.80)	$ (176.37)	$ (189.94)	$ (203.50)	$ (217.07)	$ (230.64)	$ (244.21)
17	Depreciation Expense (based on model term rate)	$ 96,505,529	$ 96,505,529	$ 96,505,529	$ 96,505,529	$ 96,505,529	$ 96,505,529	$ 96,505,529	$ 96,505,529	$ 96,505,529	$ 96,505,529
18	Deferred Tax Amortization (based on model term rate)	$ 17,430,951	$ 17,430,951	$ 17,430,951	$ 17,430,951	$ 17,430,951	$ 17,430,951	$ 17,430,951	$ 17,430,951	$ 17,430,951	$ 17,430,951
19	Net Utility Plant										

NW Natural
Exhibit NW Natural/4003, Therrien - Existing System Revenue Requirements

	Description	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25
	Revenue Requirement Calculations						
1	Gross Plant	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881
2	Accumulated Depreciation	$ (3,424,359,708)	$ (3,520,865,237)	$ (3,617,370,766)	$ (3,713,876,295)	$ (3,810,381,824)	$ (3,906,887,352)
3	Net Plant	$ 579,033,173	$ 482,527,644	$ 386,022,115	$ 289,516,586	$ 193,011,058	$ 96,505,529
4	Deferred Taxes	$ (104,585,706)	$ (87,154,755)	$ (69,723,804)	$ (52,292,853)	$ (34,861,902)	$ (17,430,951)
5	Average Rate Base (Plant related)	$ 474,447,467	$ 395,372,889	$ 316,298,311	$ 237,223,733	$ 158,149,156	$ 79,074,578
6	Pre-Tax ROR	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%
7	Return and Taxes	$ 42,954,990	$ 35,795,825	$ 28,636,660	$ 21,477,495	$ 14,318,330	$ 7,159,165
8	Book Depreciation	96,505,529	96,505,529	96,505,529	96,505,529	96,505,529	96,505,529
9	O&M	539,667,000	539,667,000	539,667,000	539,667,000	539,667,000	539,667,000
10	Property Taxes	8,685,498	7,237,915	5,790,332	4,342,749	2,895,166	1,447,583
11	Franchise Tax and Comm Fees	19,384,278	19,141,718	18,899,159	18,656,599	18,414,040	18,171,480
12	Annual Revenue Requirement	$ 707,197,294	$ 698,347,987	$ 689,498,679	$ 680,649,372	$ 671,800,064	$ 662,950,757
13	No. of Customers	652,270	652,270	652,270	652,270	652,270	652,270
14	Existing Plant Revenue Requirement Per Customer	$ 1,084.21	$ 1,070.64	$ 1,057.08	$ 1,043.51	$ 1,029.94	$ 1,016.38
15	YoY Change	$ (13.57)	$ (13.57)	$ (13.57)	$ (13.57)	$ (13.57)	$ (13.57)
16	Cumulative Change	$ (257.77)	$ (271.34)	$ (284.91)	$ (298.47)	$ (312.04)	$ (325.61)
17	Depreciation Expense (based on model term rate)	$ 96,505,529	$ 96,505,529	$ 96,505,529	$ 96,505,529	$ 96,505,529	$ 96,505,529
18	Deferred Tax Amortization (based on model term rate)	$ 17,430,951	$ 17,430,951	$ 17,430,951	$ 17,430,951	$ 17,430,951	$ 17,430,951
19	Net Utility Plant						

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Gregg H. Therrien

LINE EXTENSION ALLOWANCE
EXHIBIT 4004

June 4, 2024

NW Natural
Exhibit NW Natural/4004, Therrien - New System Non-Growth Capital Expenditure Revenue Requirements

	Description		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14
1	**Rate Base Calculation**															
2	Capex (MID) (oregon share @90%)	*Revised*	$ 220,500,000	$ 218,700,000	$ 180,000,000	$ 180,900,000	$ 180,000,000	$ 162,000,000	$ 181,800,000	$ 181,800,000	$ 181,800,000	$ 181,800,000	$ 181,800,000	$ 181,800,000	$ 181,800,000	$ 181,800,000
3	Cumulative Capex		$ 220,500,000	$ 439,200,000	$ 619,200,000	$ 800,100,000	$ 980,100,000	$ 1,142,100,000	$ 1,323,900,000	$ 1,505,700,000	$ 1,687,500,000	$ 1,869,300,000	$ 2,051,100,000	$ 2,232,900,000	$ 2,414,700,000	$ 2,596,500,000
4	Accumulated Depreciation		(8,820,000)	(26,388,000)	(51,156,000)	(83,160,000)	(122,364,000)	(168,048,000)	(221,004,000)	(281,232,000)	(348,732,000)	(423,504,000)	(505,548,000)	(594,864,000)	(691,452,000)	(795,312,000)
5	Net Plant (Low)		$ 211,680,000	$ 412,812,000	$ 568,044,000	$ 716,940,000	$ 857,736,000	$ 974,052,000	$ 1,102,896,000	$ 1,224,468,000	$ 1,338,768,000	$ 1,445,796,000	$ 1,545,552,000	$ 1,638,036,000	$ 1,723,248,000	$ 1,801,188,000
6	Deferred Tax Reserve		148,860	(1,620,212)	(4,993,751)	(9,313,536)	(14,371,394)	(19,969,391)	(25,739,824)	(31,723,334)	(37,922,873)	(44,372,283)	(51,074,504)	(58,026,196)	(65,224,563)	(72,652,460)
7	Year End Rate Base Additions		$ 211,828,860	$ 411,191,788	$ 563,050,249	$ 707,626,464	$ 843,364,606	$ 954,082,609	$ 1,077,156,176	$ 1,192,744,666	$ 1,300,845,127	$ 1,401,423,717	$ 1,494,477,496	$ 1,580,009,804	$ 1,658,023,437	$ 1,728,535,540
	Revenue Requirement Calculations															
8	Average Rate Base		$ 105,914,430	$ 311,510,324	$ 487,121,019	$ 635,338,357	$ 775,495,535	$ 898,723,607	$ 1,015,619,393	$ 1,134,950,421	$ 1,246,794,897	$ 1,351,134,422	$ 1,447,950,606	$ 1,537,243,650	$ 1,619,016,620	$ 1,693,279,489
9	Pre-Tax ROR		9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%
10	Return and Taxes		$ 9,589,161	$ 28,203,171	$ 44,102,414	$ 57,521,548	$ 70,210,941	$ 81,367,625	$ 91,951,004	$ 102,754,862	$ 112,880,911	$ 122,327,486	$ 131,092,920	$ 139,177,233	$ 146,580,702	$ 153,304,230
11	Book Depreciation	4.0%	8,820,000	17,568,000	24,768,000	32,004,000	39,204,000	45,684,000	52,956,000	60,228,000	67,500,000	74,772,000	82,044,000	89,316,000	96,588,000	103,860,000
12	O&M															
13	Property Taxes	1.5%	3,175,200	6,192,180	8,520,660	10,754,100	12,866,040	14,610,780	16,543,440	18,367,020	20,081,520	21,686,940	23,183,280	24,570,540	25,848,720	27,017,820
14	Annual Revenue Requirement - pre franch		21,584,361	51,963,351	77,391,074	100,279,648	122,280,981	141,662,405	161,450,444	181,349,882	200,462,431	218,786,426	236,320,200	253,063,773	269,017,422	284,182,050
15																
16	Franchise Tax and Comm Fees	2.7%	608,301	1,464,456	2,181,073	2,826,129	3,446,182	3,992,398	4,550,074	5,110,890	5,649,529	6,165,944	6,660,090	7,131,965	7,581,579	8,008,955
17	Annual Revenue Requirement		$ 22,192,662	$ 53,427,807	$ 79,572,146	$ 103,105,777	$ 125,727,162	$ 145,654,803	$ 166,000,518	$ 186,460,772	$ 206,111,960	$ 224,952,370	$ 242,980,290	$ 260,195,738	$ 276,599,001	$ 292,191,005
18	No. of Customers		652,270	652,270	652,270	652,270	652,270	652,270	652,270	652,270	652,270	652,270	652,270	652,270	652,270	652,270
19	Rev Req per Cust ("cost avoidance")		$ 34.02	$ 81.91	$ 121.99	$ 158.07	$ 192.75	$ 223.30	$ 254.50	$ 285.86	$ 315.99	$ 344.88	$ 372.52	$ 398.91	$ 424.06	$ 447.96
20	Deferred Taxes:		1	2	3	4	5	6	7	8	9	10	11	12	13	14
21	20-year MACRS		3.750%	7.219%	6.677%	6.177%	5.713%	5.285%	4.888%	4.522%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%
		Invmt. Yr.														
22	Tax Depreciation	Year 1	8,268,750	15,917,895	14,722,785	13,620,285	12,597,165	11,653,425	10,778,040	9,971,010	9,838,710	9,836,505	9,838,710	9,836,505	9,838,710	9,836,505
23		Year 2		8,201,250	15,787,953	14,602,599	13,509,099	12,494,331	11,558,295	10,690,056	9,889,614	9,758,394	9,756,207	9,758,394	9,756,207	9,758,394
24		Year 3			6,750,000	12,994,200	12,018,600	11,118,600	10,283,400	9,513,000	8,798,400	8,139,600	8,031,600	8,029,800	8,031,600	8,029,800
25		Year 4				6,783,750	13,059,171	12,078,693	11,174,193	10,334,817	9,560,565	8,842,392	8,180,298	8,071,758	8,069,949	8,071,758
26		Year 5					6,750,000	12,994,200	12,018,600	11,118,600	10,283,400	9,513,000	8,798,400	8,139,600	8,031,600	8,029,800
27		Year 6						6,075,000	11,694,780	10,816,740	10,006,740	9,255,060	8,561,700	7,918,560	7,325,640	7,228,440
28		Year 7							6,817,500	13,124,142	12,138,786	11,229,786	10,386,234	9,608,130	8,886,384	8,220,996
29		Year 8								6,817,500	13,124,142	12,138,786	11,229,786	10,386,234	9,608,130	8,886,384
30		Year 9									6,817,500	13,124,142	12,138,786	11,229,786	10,386,234	9,608,130
31		Year 10										6,817,500	13,124,142	12,138,786	11,229,786	10,386,234
32		Year 11											6,817,500	13,124,142	12,138,786	11,229,786
33		Year 12												6,817,500	13,124,142	12,138,786
34		Year 13													6,817,500	13,124,142
35		Year 14														6,817,500
36		Year 15														
37		Year 16														
38		Year 17														
39		Year 18														
40		Year 19														
41		Year 20														
42		Sum	8,268,750	24,119,145	37,260,738	48,000,834	57,934,035	66,414,249	74,324,808	82,385,865	90,457,857	98,655,165	106,863,363	115,059,195	123,244,668	131,366,655
43	Book Depreciation		8,820,000	17,568,000	24,768,000	32,004,000	39,204,000	45,684,000	52,956,000	60,228,000	67,500,000	74,772,000	82,044,000	89,316,000	96,588,000	103,860,000
44	Variance		($551,250)	$6,551,145	$12,492,738	$15,996,834	$18,730,035	$20,730,249	$21,368,808	$22,157,865	$22,957,857	$23,883,165	$24,819,363	$25,743,195	$26,656,668	$27,506,655
45	Deferred Taxes	27.00%	($148,860)	$1,769,071	$3,373,539	$4,319,785	$5,057,859	$5,597,996	$5,770,433	$5,983,510	$6,199,540	$6,449,410	$6,702,221	$6,951,692	$7,198,367	$7,427,897

NW Natural
Exhibit NW Natural/4004, Therrien - New System Non-Growth Capital Expenditure Revenue Requirements

	Description	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25
1	**Rate Base Calculation**											
2	Capex (MID) (oregon share @90%)	$ 181,800,000	$ 181,800,000	$ 181,800,000	$ 181,800,000	$ 181,800,000	$ 181,800,000	$ 181,800,000	$ 181,800,000	$ 181,800,000	$ 181,800,000	$ 181,800,000
3	Cumulative Capex	$ 2,778,300,000	$ 2,960,100,000	$ 3,141,900,000	$ 3,323,700,000	$ 3,505,500,000	$ 3,687,300,000	$ 3,869,100,000	$ 4,050,900,000	$ 4,232,700,000	$ 4,414,500,000	$ 4,596,300,000
4	Accumulated Depreciation	(906,444,000)	(1,024,848,000)	(1,150,524,000)	(1,283,472,000)	(1,423,692,000)	(1,571,184,000)	(1,725,948,000)	(1,887,984,000)	(2,057,292,000)	(2,233,872,000)	(2,417,724,000)
5	Net Plant (Low)	$ 1,871,856,000	$ 1,935,252,000	$ 1,991,376,000	$ 2,040,228,000	$ 2,081,808,000	$ 2,116,116,000	$ 2,143,152,000	$ 2,162,916,000	$ 2,175,408,000	$ 2,180,628,000	$ 2,178,576,000
6	Deferred Tax Reserve	(80,307,219)	(88,188,247)	(96,296,137)	(104,630,296)	(113,191,317)	(121,978,607)	(127,823,338)	(127,704,890)	(122,133,336)	(111,581,775)	(96,278,099)
7	Year End Rate Base Additions	$ 1,791,548,781	$ 1,847,063,753	$ 1,895,079,863	$ 1,935,597,704	$ 1,968,616,683	$ 1,994,137,393	$ 2,015,328,662	$ 2,035,211,110	$ 2,053,274,664	$ 2,069,046,225	$ 2,082,297,901
	Revenue Requirement Calculations											
8	Average Rate Base	$ 1,760,042,160	$ 1,819,306,267	$ 1,871,071,808	$ 1,915,338,783	$ 1,952,107,194	$ 1,981,377,038	$ 2,004,733,028	$ 2,025,269,886	$ 2,044,242,887	$ 2,061,160,445	$ 2,075,672,063
9	Pre-Tax ROR	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%	9.0537%
10	Return and Taxes	$ 159,348,714	$ 164,714,300	$ 169,400,991	$ 173,408,784	$ 176,737,681	$ 179,387,681	$ 181,502,259	$ 183,361,602	$ 185,079,359	$ 186,611,021	$ 187,924,858
11	Book Depreciation	111,132,000	118,404,000	125,676,000	132,948,000	140,220,000	147,492,000	154,764,000	162,036,000	169,308,000	176,580,000	183,852,000
12	O&M											
13	Property Taxes	28,077,840	29,028,780	29,870,640	30,603,420	31,227,120	31,741,740	32,147,280	32,443,740	32,631,120	32,709,420	32,678,640
14	Annual Revenue Requirement - pre francl	298,558,554	312,147,080	324,947,631	336,960,204	348,184,801	358,621,421	368,413,539	377,841,342	387,018,479	395,900,441	404,455,498
15												
16	Franchise Tax and Comm Fees	8,414,121	8,797,079	9,157,831	9,496,375	9,812,712	10,106,842	10,382,808	10,648,507	10,907,141	11,157,457	11,398,560
17	Annual Revenue Requirement	$ 306,972,675	$ 320,944,160	$ 334,105,461	$ 346,456,579	$ 357,997,513	$ 368,728,263	$ 378,796,347	$ 388,489,849	$ 397,925,620	$ 407,057,898	$ 415,854,058
18	No. of Customers	652,270	652,270	652,270	652,270	652,270	652,270	652,270	652,270	652,270	652,270	652,270
19	Rev Req per Cust ("cost avoidance")	$ 470.62	$ 492.04	$ 512.22	$ 531.16	$ 548.85	$ 565.30	$ 580.74	$ 595.60	$ 610.06	$ 624.06	$ 637.55
20	Deferred Taxes:	15	16	17	18	19	20	21	22	23	24	25
21	20-year MACRS	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	2.231%	0.000%	0.000%	0.000%	0.000%
22	Tax Depreciation	9,838,710	9,836,505	9,838,710	9,836,505	9,838,710	9,836,505	4,919,355	-	-	-	-
23		9,756,207	9,758,394	9,756,207	9,758,394	9,756,207	9,758,394	9,756,207	4,879,197	-	-	-
24		8,031,600	8,029,800	8,031,600	8,029,800	8,031,600	8,029,800	8,031,600	8,029,800	4,015,800	-	-
25		8,069,949	8,071,758	8,069,949	8,071,758	8,069,949	8,071,758	8,069,949	8,071,758	8,069,949	4,035,879	-
26		8,031,600	8,029,800	8,031,600	8,029,800	8,031,600	8,029,800	8,031,600	8,029,800	8,031,600	8,029,800	4,015,800
27		7,226,820	7,228,440	7,226,820	7,228,440	7,226,820	7,228,440	7,226,820	7,228,440	7,226,820	7,228,440	7,226,820
28		8,111,916	8,110,098	8,111,916	8,110,098	8,111,916	8,110,098	8,111,916	8,110,098	8,111,916	8,110,098	8,111,916
29		8,220,996	8,111,916	8,110,098	8,111,916	8,110,098	8,111,916	8,110,098	8,111,916	8,110,098	8,111,916	8,110,098
30		8,886,384	8,220,996	8,111,916	8,110,098	8,111,916	8,110,098	8,111,916	8,110,098	8,111,916	8,110,098	8,111,916
31		9,608,130	8,886,384	8,220,996	8,111,916	8,110,098	8,111,916	8,110,098	8,111,916	8,110,098	8,111,916	8,110,098
32		10,386,234	9,608,130	8,886,384	8,220,996	8,111,916	8,110,098	8,111,916	8,110,098	8,111,916	8,110,098	8,111,916
33		11,229,786	10,386,234	9,608,130	8,886,384	8,220,996	8,111,916	8,110,098	8,111,916	8,110,098	8,111,916	8,110,098
34		12,138,786	11,229,786	10,386,234	9,608,130	8,886,384	8,220,996	8,111,916	8,110,098	8,111,916	8,110,098	8,111,916
35		13,124,142	12,138,786	11,229,786	10,386,234	9,608,130	8,886,384	8,220,996	8,111,916	8,110,098	8,111,916	8,110,098
36		6,817,500	13,124,142	12,138,786	11,229,786	10,386,234	9,608,130	8,886,384	8,220,996	8,111,916	8,110,098	8,111,916
37			6,817,500	13,124,142	12,138,786	11,229,786	10,386,234	9,608,130	8,886,384	8,220,996	8,111,916	8,110,098
38				6,817,500	13,124,142	12,138,786	11,229,786	10,386,234	9,608,130	8,886,384	8,220,996	8,111,916
39					6,817,500	13,124,142	12,138,786	11,229,786	10,386,234	9,608,130	8,886,384	8,220,996
40						6,817,500	13,124,142	12,138,786	11,229,786	10,386,234	9,608,130	8,886,384
41							6,817,500	13,124,142	12,138,786	11,229,786	10,386,234	9,608,130
42		139,478,760	147,588,669	155,700,774	163,810,683	171,922,788	180,032,697	176,407,947	161,597,367	148,675,671	137,505,933	127,180,116
43	Book Depreciation	111,132,000	118,404,000	125,676,000	132,948,000	140,220,000	147,492,000	154,764,000	162,036,000	169,308,000	176,580,000	183,852,000
44	Variance	$28,346,760	$29,184,669	$30,024,774	$30,862,683	$31,702,788	$32,540,697	$21,643,947	($438,633)	($20,632,329)	($39,074,067)	($56,671,884)
45	Deferred Taxes	$7,654,759	$7,881,028	$8,107,890	$8,334,159	$8,561,021	$8,787,290	$5,844,731	($118,448)	($5,571,554)	($10,551,561)	($15,303,676)

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Gregg H. Therrien

LINE EXTENSION ALLOWANCE EXHIBIT 4005

June 4, 2024

NW Natural
Exhibit NW Natural/4005, Therrien - Supporting DCF Assumptions

1	**General Inputs:**		
2	Start Date:	11/1/2024	<-- *input*
3	Year 1:	2025	<-- *input*
4	UPC Therms - New Customers	1000	<-- *input*
5	NPV Number of Years:	25	<-- *input*
6	Model depreciation assumption	4.00%	
7	**Distribution Revenue Calculation:**		
8	UPC (therms)	1000	
9			
10	Customer Charge	**$26.25**	<-- *input (tariff)*
11	Rate per Therm	0.90649	<-- *input (tariff)*
12	**Annual Distribution Revenue (Real $)**	**$1,221.49**	
13	**NPV**	($0)	
14			
15	**Construction Costs**	**$1,664**	***Goal seek to produce 0 NPV***
16	**Times Margin**	1.4	

Model Results at Proposed Consumption Levels (Therms)

UPC (Therms)	250	450	650	1,000
LEA	$3,385	$2,926	$2,467	$1,664
Times Margin	6.2	4.0	2.7	1.4
Rev Req B/E Year	Year 11	Year 11	Year 11	Year 12

17	**Cost of Capital**				
18				**Weighted**	**After-tax**
19		**% of Capital**	**Cost**	**Cost**	**Cost**
20					
21	**Debt**	50.00%	4.271%	2.136%	1.559%
22	**Common Equity**	50.00%	10.100%	5.050%	5.050%
23		100.00%		**7.186%**	**6.609%**

24	**Other Costs:**		
25	**State Tax Rate**	7.60%	<-- *input*
26	**Federal Tax Rate**	21.00%	<-- *input*
27	**Revenue Sensitive Rate (Franchise tax, Comm fee)**	2.741%	<-- *input*
28	**Property Tax Rate**	1.50%	<-- *input*
29	**Incremental O&M**	79.19	<-- *input*

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Gregg H. Therrien

LINE EXTENSION ALLOWANCE EXHIBIT 4006

June 4, 2024

NW Natural/4006
Therrien/Page 1

NW Natural
Exhibit NW Natural/4006, Therrien - CPP Proxy Cost and Revenue Assumptions

Growth Rate	0.15%
2022-24 CCI Cap	10.00%
2025-27 CCI Cap	15.00%
Beyond 2027	20.00%

		Source	2024	2025	2026	2027	2028	2029	2030	2031
1	**Normalized Load**	NWN internal data	1,088,444,642	1,090,264,509	1,091,897,976	1,093,353,861	1,094,995,193	1,096,638,989	1,098,285,253	1,099,933,988
2	**Non-Combustion Exclusion**	NWN internal data	20,733,841	20,733,841	20,733,841	20,733,841	20,733,841	20,733,841	20,733,841	20,733,841
3	**RNG**	NWN internal data	11,540,147	11,540,147	11,540,147	11,540,147	11,540,147	11,540,147	11,540,147	11,540,147
4	**MT CO2e**	NWN internal data	5,609,893	5,619,559	5,628,235	5,635,968	5,644,686	5,653,417	5,662,161	5,670,918
5	**Compliance Curve (MT CO2e)**	NWN internal data	5,316,897	5,095,359	4,873,822	4,652,285	4,430,747	4,209,210	3,987,673	3,766,135
6	**Over (Under) Compliance**		292,996	524,200	754,413	983,683	1,213,939	1,444,207	1,674,488	1,904,783
7	**CCI Cap**		560,989	842,934	844,235	845,395	1,128,937	1,130,683	1,132,432	1,134,184
8	**Over (Under) CCI Cap**		(267,994)	(318,734)	(89,822)	138,288	85,002	313,523	542,056	770,599
9	**Accumulated Over (Under) CCI Cap**		(267,994)	(586,728)	(676,550)	(538,263)	(453,261)	(139,738)	402,318	1,172,917
10	**New Customer Therms**	NWN internal data	450	450	450	450	450	450	450	450
11	**New Customer MT CO2e**	NWN internal data	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39
12	**CPP Proxy Cost of New Customer**	NWN internal data	$ 150.65	$ 150.65	$ 150.65	$ 990.00	$ 990.00	$ 990.00	$ 990.00	$ 990.00
13	**CPP Proxy Cost per Therm (Revised Estimate)**		$ 0.33	$ 0.33	$ 0.33	$ 2.20	$ 2.20	$ 2.20	$ 2.20	$ 2.20
14	**CPP Proxy Cost**		$ 334.78	$ 334.78	$ 334.78	$ 2,200.00	$ 2,200.00	$ 2,200.00	$ 2,200.00	$ 2,200.00
15	**2022 CPP Annual Cap (MT CO2e)**	DEQ Greenhouse Gas Emissions Calculations to supplement rulemaking GHGCR2021, Calculation for proposed OAR 340-271-9000 Table 2: Oregon Climate Protection Program Caps	28,081,335							
16	**CPP Annual Caps (MT CO2e)**	DEQ Greenhouse Gas Emissions Calculations to supplement rulemaking GHGCR2021, Calculation for proposed OAR 340-271-9000 Table 2: Oregon Climate Protection Program Caps	25,921,232	25,763,209	24,637,057	23,510,904	23,013,190	21,842,149	20,671,108	19,910,424
17	**CPP Revenue Multiplier**		-7.69%	-8.26%	-12.27%	-16.28%	-18.05%	-22.22%	-26.39%	-29.10%
18	**CPP Revenue**		$ 25.75	$ 27.64	$ 41.06	$ 358.07	$ 397.06	$ 488.80	$ 580.55	$ 640.14

NW Natural
Exhibit NW Natural/4006, Therrien - CPP Proxy Cost and Revenue Assumptions

		2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
1	**Normalized Load**	1,101,585,198	1,103,238,887	1,104,895,059	1,106,553,717	1,108,214,864	1,109,878,506	1,111,544,645	1,113,213,285	1,114,884,430	1,116,558,083	1,118,234,249
2	**Non-Combustion Exclusion**	20,733,841	20,733,841	20,733,841	20,733,841	20,733,841	20,733,841	20,733,841	20,733,841	20,733,841	20,733,841	20,733,841
3	**RNG**	11,540,147	11,540,147	11,540,147	11,540,147	11,540,147	11,540,147	11,540,147	11,540,147	11,540,147	11,540,147	11,540,147
4	**MT CO2e**	5,679,688	5,688,472	5,697,269	5,706,079	5,714,902	5,723,738	5,732,588	5,741,451	5,750,327	5,759,217	5,768,119
5	**Compliance Curve (MT CO2e)**	3,544,598	3,323,061	3,101,523	2,879,986	2,726,387	2,572,787	2,419,188	2,265,589	2,111,990	1,958,390	1,804,791
6	**Over (Under) Compliance**	2,135,090	2,365,411	2,595,746	2,826,093	2,988,515	3,150,951	3,313,400	3,475,862	3,638,337	3,800,827	3,963,328
7	**CCI Cap**	1,135,938	1,137,694	1,139,454	1,141,216	1,142,980	1,144,748	1,146,518	1,148,290	1,150,065	1,151,843	1,153,624
8	**Over (Under) CCI Cap**	999,153	1,227,717	1,456,292	1,684,877	1,845,534	2,006,203	2,166,882	2,327,572	2,488,272	2,648,983	2,809,705
9	**Accumulated Over (Under) CCI Cap**	2,172,070	3,399,786	4,856,078	6,540,955	8,386,490	10,392,693	12,559,575	14,887,147	17,375,418	20,024,402	22,834,106
10	**New Customer Therms**	450	450	450	450	450	450	450	450	450	450	450
11	**New Customer MT CO2e**	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39
12	**CPP Proxy Cost of New Customer**	$ 990.00	$ 990.00	$ 990.00	$ 990.00	$ 990.00	$ 990.00	$ 990.00	$ 990.00	$ 990.00	$ 990.00	$ 990.00
13	**CPP Proxy Cost per Therm (Revised Estimate)**	$ 2.23	$ 2.26	$ 2.29	$ 2.32	$ 2.35	$ 2.38	$ 2.41	$ 2.44	$ 2.47	$ 2.50	$ 2.50
14	**CPP Proxy Cost**	$ 2,230.00	$ 2,260.00	$ 2,290.00	$ 2,320.00	$ 2,350.00	$ 2,380.00	$ 2,410.00	$ 2,440.00	$ 2,470.00	$ 2,500.00	$ 2,500.00
15	**2022 CPP Annual Cap (MT CO2e)**											
16	**CPP Annual Caps (MT CO2e)**	18,688,088	17,465,752	16,243,416	15,021,080	14,219,956	13,418,831	12,617,707	11,816,583	11,015,459	10,214,334	9,413,210
17	**CPP Revenue Multiplier**	-33.45%	-37.80%	-42.16%	-46.51%	-49.36%	-52.21%	-55.07%	-57.92%	-60.77%	-63.63%	-66.48%
18	**CPP Revenue**	$ 745.94	$ 854.35	$ 965.37	$ 1,079.00	$ 1,160.00	$ 1,242.70	$ 1,327.12	$ 1,413.25	$ 1,501.09	$ 1,590.65	$ 1,661.97

NW Natural
Exhibit NW Natural/4006, Therrien - CPP Proxy Cost and Revenue Assumptions

		2043	2044	2045	2046	2047	2048	2049
1	Normalized Load	1,119,912,932	1,121,594,134					
2	Non-Combustion Exclusion	20,733,841	20,733,841					
3	RNG	11,540,147	11,540,147					
4	MT CO2e	5,777,036	5,785,965					
5	Compliance Curve (MT CO2e)	1,651,192	1,497,593					
6	Over (Under) Compliance	4,125,844	4,288,372					
7	CCI Cap	1,155,407	1,157,193					
8	Over (Under) CCI Cap	2,970,437	3,131,179					
9	Accumulated Over (Under) CCI Cap	25,804,543	28,935,722					
10	New Customer Therms	450	450	450	450	450	450	450
11	New Customer MT CO2e	2.39	2.39	2.39	2.39	2.39	2.39	2.39
12	CPP Proxy Cost of New Customer	$ 990.00	$ 990.00	$ 990.00	$ 990.00	$ 990.00	$ 990.00	$ 990.00
13	CPP Proxy Cost per Therm (Revised Estimate)	$ 2.50	$ 2.50	$ 2.50	$ 2.50	$ 2.50	$ 2.50	$ 2.50
14	CPP Proxy Cost	$ 2,500.00	$ 2,500.00	$ 2,500.00	$ 2,500.00	$ 2,500.00	$ 2,500.00	$ 2,500.00
15	2022 CPP Annual Cap (MT CO2e)							
16	CPP Annual Caps (MT CO2e)	8,612,086	7,810,962	7,009,837	6,208,713	5,407,589	4,606,465	3,805,340
17	CPP Revenue Multiplier	-69.33%	-72.18%	-75.04%	-77.89%	-80.74%	-83.60%	-86.45%
18	CPP Revenue	$ 1,733.29	$ 1,804.61	$ 1,875.93	$ 1,947.26	$ 2,018.58	$ 2,089.90	$ 2,161.22

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Gregg H. Therrien

LINE EXTENSION ALLOWANCE
EXHIBIT 4007

June 4, 2024

NW Natural
Exhibit NW Natural/4007, Therrien - Economic Impact on Existing Customers

			LEA Determined	$1,664							
			Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9
1	Depreciation (using book depreciation rates)	4.00%	67	67	67	67	67	67	67	67	67
2	O&M		79	79	79	79	79	79	79	79	79
3	Property Taxes		24	23	22	21	20	19	18	17	16
	Taxes on Equity Return										
4	State		9	8	8	7	7	7	6	6	5
5	Federal		22	21	20	19	18	17	16	15	14
6	Total Taxes		30	29	28	26	25	23	22	21	19
	Return on Rate Base										
7	Debt		35	33	32	30	28	27	25	24	22
8	Common Equity		82	79	75	71	67	63	60	56	53
9	Total Return		117	112	106	101	95	90	85	80	75
10	Subtotal Cost of Service		318	310	302	294	286	279	271	264	257
11	Revenue Sensitive Items		9	9	9	8	8	8	8	7	7
12	Total Cost of Service		327	319	311	302	294	286	279	271	264
13	Cost of Proxy CPP ($/Therm)		0.33	0.33	2.20	2.20	2.20	2.20	2.20	2.23	2.26
14	UPC (Therms)		1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
15	New Customer Proxy Cost of CPP		335	335	2,200	2,200	2,200	2,200	2,200	2,230	2,260
16	Less: New Customer Recovery of CPP (re class WACOD)		-28	-41	-358	-397	-489	-581	-640	-746	-854
17	Nominal Change in Base Rate Revenue per Customer (Rate Base)		0	14	27	41	54	68	81	95	109
18	Less: Contribution to New Non-Growth Capex		-34	-82	-122	-158	-193	-223	-254	-286	-316
19	Total Cost of Service (Net)		600	544	2,058	1,988	1,867	1,750	1,666	1,564	1,462
20	New Customer Revenue		$1,221	$1,221	$1,221	$1,221	$1,221	$1,221	$1,221	$1,221	$1,221
21	Revenue less cost of service (impact on existing customers)		$622	$677	($836)	($766)	($646)	($529)	($444)	($343)	($241)

NW Natural
Exhibit NW Natural/4007, Therrien - Economic Impact on Existing Customers

			Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18
1	Depreciation (using book depreciation rates)	4.00%	67	67	67	67	67	67	67	67	67
2	O&M		79	79	79	79	79	79	79	79	79
3	Property Taxes		15	14	13	12	11	10	9	8	7
	Taxes on Equity Return										
4	State		5	5	4	4	4	3	3	3	2
5	Federal		13	12	11	10	9	8	8	7	6
6	Total Taxes		18	17	16	14	13	12	10	9	8
	Return on Rate Base										
7	Debt		21	19	18	16	15	13	12	11	9
8	Common Equity		49	46	42	39	35	32	28	25	21
9	Total Return		70	65	60	55	50	45	40	35	31
10	Subtotal Cost of Service		249	242	235	228	221	213	206	199	192
11	Revenue Sensitive Items		7	7	7	6	6	6	6	6	5
12	Total Cost of Service		256	249	242	234	227	219	212	204	197
13	Cost of Proxy CPP ($/Therm)		2.29	2.32	2.35	2.38	2.41	2.44	2.47	2.50	2.50
14	UPC (Therms)		1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
15	New Customer Proxy Cost of CPP		2,290	2,320	2,350	2,380	2,410	2,440	2,470	2,500	2,500
16	Less: New Customer Recovery of CPP (re class WACOD)		-965	-1,079	-1,160	-1,243	-1,327	-1,413	-1,501	-1,591	-1,662
17	Nominal Change in Base Rate Revenue per Customer (Rate Base)		122	136	149	163	176	190	204	217	231
18	Less: Contribution to New Non-Growth Capex		-345	-373	-399	-424	-448	-471	-492	-512	-531
19	Total Cost of Service (Net)		1,358	1,253	1,182	1,110	1,038	965	892	819	735
20	New Customer Revenue		$1,221	$1,221	$1,221	$1,221	$1,221	$1,221	$1,221	$1,221	$1,221
21	Revenue less cost of service (impact on existing customers)		($137)	($32)	$40	$111	$183	$256	$329	$403	$487

NW Natural
Exhibit NW Natural/4007, Therrien - Economic Impact on Existing Customers

			Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25
1	**Depreciation (using book depreciation rates)**	4.00%	67	67	67	67	67	67	67
2	**O&M**		79	79	79	79	79	79	79
3	**Property Taxes**		6	5	4	3	2	1	0
	Taxes on Equity Return								
4	**State**		2	2	1	1	1	0	0
5	**Federal**		5	4	3	2	2	1	0
6	**Total Taxes**		7	5	4	3	2	1	0
	Return on Rate Base								
7	**Debt**		8	6	5	4	3	2	1
8	**Common Equity**		18	15	11	9	6	4	1
9	**Total Return**		26	21	16	12	9	5	2
10	**Subtotal Cost of Service**		184	177	170	165	159	154	148
11	**Revenue Sensitive Items**		5	5	5	5	4	4	4
12	**Total Cost of Service**		190	182	175	169	164	158	153
13	**Cost of Proxy CPP ($/Therm)**		2.50	2.50	2.50	2.50	2.50	2.50	2.50
14	**UPC (Therms)**		1,000	1,000	1,000	1,000	1,000	1,000	1,000
15	**New Customer Proxy Cost of CPP**		2,500	2,500	2,500	2,500	2,500	2,500	2,500
16	**Less: New Customer Recovery of CPP (re class WACOD)**		-1,733	-1,805	-1,876	-1,947	-2,019	-2,090	-2,161
17	**Nominal Change in Base Rate Revenue per Customer (Rate Base)**		244	258	271	285	298	312	326
18	**Less: Contribution to New Non-Growth Capex**		-549	-565	-581	-596	-610	-624	-638
19	**Total Cost of Service (Net)**		652	570	490	411	334	256	179
20	**New Customer Revenue**		$1,221	$1,221	$1,221	$1,221	$1,221	$1,221	$1,221
21	**Revenue less cost of service (impact on existing customers)**		$570	$651	$732	$810	$888	$965	$1,042

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Gregg H. Therrien

LINE EXTENSION ALLOWANCE EXHIBIT 4008

June 4, 2024

NW Natural/4008

State	Utility	Allowance Portion	Excess Portion
Alabama	Spire Alabama	NPV Method	CIAC
Alaska	ENSTAR Natural Gas Company	Revenue/Margin Multiplier	CIAC
Arizona	Southwest Gas Corporation	NPV Method	CIAC / Surcharge
Arizona	UniSource Energy Services	NPV Method	CIAC / Surcharge
Arkansas	Arkansas Oklahoma Gas	NPV Method	CIAC
Arkansas	Summit Utilities	NPV Method	CIAC / Surcharge
Arkansas	Black Hills Energy	Footage Allowance	Surcharge
California	Pacific Gas and Electric Company	No Allowance	CIAC
California	Southern California Gas	No Allowance	CIAC
California	Southwest Gas Corporation	No Allowance	CIAC
Colorado	Atmos Energy	No Allowance	CIAC
Colorado	Black Hills Energy	Dollar Allowance	CIAC
Colorado	Public Service Company of Colorado (dba Xcel Energy)	Dollar Allowance	CIAC
Connecticut	Connecticut Natural Gas Company	NPV Method	CIAC
Connecticut	The Southern Connecticut Gas Company	NPV Method	CIAC
Delaware	Chesapeake Utilities	NPV Method	CIAC / Surcharge
Delaware	Delmarva Power & Light	NPV Method	Surcharge
District of Columbia	Washington Gas Light Company	NPV Method	CIAC
Florida	Florida Public Utilities Company	Revenue/Margin Multiplier	CIAC
Florida	Peoples Gas System	Revenue/Margin Multiplier	Surcharge
Florida	Florida City Gas	Revenue/Margin Multiplier	CIAC
Georgia	Atlanta Gas Light	Footage Allowance	CIAC
Hawaii	Hawai'i Gas	Revenue/Margin Multiplier	CIAC
Idaho	Avista Utilities	Revenue/Margin Multiplier	Surcharge
Idaho	Intermountain Gas Company	Revenue/Margin Multiplier	CIAC
Illinois	People's Gas	Footage Allowance	CIAC
Illinois	Nicor Gas	Footage Allowance	CIAC
Indiana	Northern Indiana Public Service Company (NIPSCO)	Footage Allowance	CIAC
Indiana	Indiana Gas Company (dba CenterPoint Energy Indiana)	Footage Allowance	CIAC
Indiana	Indiana Natural Gas Corporation	Revenue/Margin Multiplier	CIAC
Indiana	Midwest Natural Gas Corporation	Revenue/Margin Multiplier	CIAC
Indiana	Ohio Valley Gas Corporation	Revenue/Margin Multiplier	CIAC
Iowa	Alliant Energy	Revenue/Margin Multiplier	CIAC

Source: Concentric Energy Advisors, Inc. research.

NW Natural/4008

State	Utility	Allowance Portion	Excess Portion
Iowa	Black Hills Energy	Revenue/Margin Multiplier	CIAC
Iowa	Midamerican Energy Company	Revenue/Margin Multiplier	CIAC
Kansas	Black Hills Energy	Footage Allowance	CIAC
Kansas	Kansas Gas Service	Footage Allowance	CIAC
Kansas	Midwest Energy	Dollar Allowance	CIAC
Kentucky	Columbia Gas of Kentucky	Footage Allowance	CIAC
Kentucky	Duke Energy Kentucky	Footage Allowance	CIAC
Kentucky	Atmos Energy Corporation	Footage Allowance	CIAC
Kentucky	Louisville Gas and Electric Company	Footage Allowance	CIAC
Louisiana	Atmos Energy Corporation	Revenue/Margin Multiplier	CIAC
Louisiana	CenterPoint Energy	Footage Allowance	CIAC
Maine	Summit Natural Gas	Dollar Allowance	CIAC
Maine	Bangor Natural Gas	Revenue/Margin Multiplier	CIAC
Maine	Northern Utilities (dba Unitil)	NPV Method	CIAC
Maryland	Baltimore Gas and Electric	NPV Method	CIAC
Maryland	Washington Gas Light Company	NPV Method	CIAC
Massachusetts	NSTAR (dba Eversource Energy)		CIAC / Surcharge
Massachusetts	New England Natural Gas Company (dba Liberty Utilities)	NPV Method	CIAC
Massachusetts	Fitchburg Gas and Electric (dba Unitil)	NPV Method	CIAC
Michigan	Consumers Energy Company	NPV Method	CIAC / Surcharge
Michigan	DTE Gas Company	NPV Method	CIAC / Surcharge
Michigan	SEMCO Energy Gas Company	NPV Method	CIAC / Surcharge
Minnesota	CenterPoint Energy	Footage Allowance	CIAC / Surcharge
Minnesota	Northern States Power Company (dba Xcel Energy)	Footage Allowance	CIAC / Surcharge
Mississippi	Atmos Energy Corporation	Footage Allowance	CIAC
Mississippi	CenterPoint Energy	Footage Allowance	CIAC
Mississippi	Spire Energy	Footage Allowance	CIAC

Source: Concentric Energy Advisors, Inc. research.

NW Natural/4008

State	Utility	Allowance Portion	Excess Portion
Missouri	Union Electric Company (dba Ameren)	Footage Allowance	CIAC
Missouri	Empire District Gas Company (dba Liberty Utilities)	Revenue/Margin Multiplier	CIAC
Missouri	Spire Missouri	Footage Allowance	CIAC / Surcharge
Montana	NorthWestern Energy	Dollar Allowance	CIAC
Nebraska	Black Hills Energy	NPV Method	CIAC
Nevada	Southwest Gas Corporation	NPV Method	CIAC / Surcharge
Nevada	Sierra Pacific Power Company (dba NV Energy)	Revenue/Margin Multiplier	CIAC
New Hampshire	Liberty Utilities	Footage Allowance	CIAC
New Hampshire	Northern Utilities (dba Unitil)	NPV Method	CIAC
New Jersey	New Jersey Natural Gas Company	Revenue/Margin Multiplier	CIAC
New Jersey	PSE&G	Revenue/Margin Multiplier	CIAC
New Mexico	New Mexico Gas Company	Revenue/Margin Multiplier	CIAC
New York	Consolidated Edison	Footage Allowance	Surcharge
New York	Central Hudson Gas & Electric	Footage Allowance	Surcharge
New York	National Fuel Gas	Footage Allowance	Surcharge
North Carolina	Public Service Company of North Carolina (dba Dominion Energy)	Footage Allowance	CIAC
North Carolina	Frontier Natural Gas	Footage Allowance	CIAC
North Carolina	Piedmont Natural Gas (dba Duke Energy)	Footage Allowance	CIAC
North Dakota	Montana-Dakota Utilities Corporation	Revenue/Margin Multiplier	CIAC
Ohio	The East Ohio Gas Company (dba Dominion Energy)	Footage Allowance	CIAC
Ohio	Duke Energy Ohio	Footage Allowance	CIAC
Ohio	Columbia Gas of Ohio	Footage Allowance	CIAC
Oklahoma	Oklahoma Natural Gas Company	Revenue/Margin Multiplier	CIAC
Oklahoma	CenterPoint Energy	Revenue/Margin Multiplier	CIAC
Oregon	Northwest Natural Gas	Revenue/Margin Multiplier	CIAC
Oregon	Cascade Natural Gas	Revenue/Margin Multiplier	CIAC
Oregon	Avista Utilities	Dollar Allowance	CIAC
Pennsylvania	Columbia Gas of Pennsylvania	Footage Allowance	CIAC
Pennsylvania	UGI Utilities	Footage Allowance	CIAC

Source: Concentric Energy Advisors, Inc. research.

State	Utility	Allowance Portion	Excess Portion
Pennsylvania	PECO Energy Company	NPV Method	CIAC
Pennsylvania	Peoples Natural Gas Company	Footage Allowance	CIAC
Rhode Island	The Narragansett Electric Company (dba Rhode Island Energy)	NPV Method	CIAC
South Carolina	Dominion Energy South Carolina	NPV Method	CIAC
South Carolina	Piedmont Natural Gas (dba Duke Energy)	Footage Allowance	CIAC
South Dakota	MidAmerican Energy Company	NPV Method	CIAC
South Dakota	Montana-Dakota Utilities	Revenue/Margin Multiplier	CIAC
South Dakota	NorthWestern Energy	Footage Allowance	CIAC
Tennessee	Atmos Energy Corporation	NPV Method	CIAC
Tennessee	Piedmont Natural Gas (dba Duke Energy)	Footage Allowance	CIAC
Tennessee	Chattanooga Gas Company	NPV Method	CIAC
Texas	Atmos Energy Corporation	Footage Allowance	CIAC
Texas	CenterPoint Energy	Footage Allowance	CIAC
Texas	Texas Gas Service Company	NPV Method	CIAC
Utah	Dominion Energy	No allowance	CIAC / Surcharge
Vermont	Vermont Gas Systems	Footage Allowance	CIAC
Virginia	Washington Gas Light Company	NPV Method	CIAC
Virginia	Columbia Gas of Virginia	NPV Method	CIAC
Virginia	Virginia Natural Gas	NPV Method	CIAC
Washington	Avista Corporation	Dollar Allowance	CIAC
Washington	Puget Sound Energy	Dollar Allowance	CIAC
Washington	Cascade Natural Gas Corporation	NPV Method	CIAC
Wisconsin	Wisconsin Power and Light (dba Alliant Energy)	Footage Allowance	CIAC
Wisconsin	Wisconsin Public Service Company	Revenue/Margin Multiplier	CIAC
Wisconsin	Wisconsin Gas (dba We Energies)	Revenue/Margin Multiplier	CIAC
Wyoming	Black Hills Energy	Dollar Allowance	CIAC
Wyoming	Dominion Energy	No Allowance	CIAC
Wyoming	Montana-Dakota Utilities	NPV Method	CIAC

Source: Concentric Energy Advisors, Inc. research.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Reply Testimony of Jeffrey M. Zaubi

SCHEDULE X ADMINISTRATION
EXHIBIT 4100

June 4, 2024

EXHIBIT 4100 – REPLY TESTIMONY – SCHEDULE X ADMINISTRATION

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and position at Northwest Natural Gas Company dba NW Natural ("NW Natural" or the "Company").

A. Jeffrey M. Zaubi, Financial Consultant 3 on the Business Analytics team.

Q. Please describe your education and employment background.

A. I have been employed by NW Natural since 2016. I work on the Business Analytics team and provide analytical and decision support for multiple groups and initiatives within the Company. Prior to working at NW Natural, I worked as a Structuring Manager at SouthStar Energy Services, which is a retail natural gas provider located in Atlanta, Georgia. I worked at SouthStar Energy Services from 2007-2016 and was mainly responsible for developing production cost models. Prior to working at SouthStar Energy Services, I worked for Accenture from 1999 – 2007 as an Information Technology professional.

I have a Bachelor of Science degree in Business Administration from Samford University, located in Birmingham, Alabama, and a Masters in Business Administration from Georgia State University, located in Atlanta, Georgia. I am also a CFA charter-holder (Chartered Financial Analyst).

Q. What is the purpose of your Reply Testimony in this proceeding?

A. The purpose of my Reply Testimony is to respond to the Opening Testimony of Bradley Cebulko on behalf of the Coalition[1] concerning the Coalition's proposed

[1] The Coalition includes the Coalition of Communities of Color, Climate Solutions, Verde, Columbia Riverkeeper, Oregon Environmental Council, Community Energy Project, and Sierra Club.

disallowance of costs associated with system investments to hook up new residential customers.

Q. Please summarize your Reply Testimony.

A. In my testimony, I:

- Provide relevant background regarding the Company's process for adding new residential and commercial customers pursuant to Schedule X of its Oregon Tariff;
- Describe the Company's process for estimating the construction costs for new residential and commercial customers; and
- Demonstrate the Company's constructions costs for adding new residential and commercial customers were prudently incurred and should be recovered.

Q. Do you include any exhibits with your testimony?

A. Yes, I am presenting the following exhibits: NW Natural/4101, Zaubi (modified version of UG 490 OPUC DR 138 Attachment 1 Amended) and NW Natural/4102, Zaubi (calculated Line Extension Allowances compared with estimated construction costs).

II. BACKGROUND REGARDING THE ADMINISTRATION OF SCHEDULE X

Q. Please explain the purpose of the Company's Schedule X to its Oregon Tariff.

A. The purpose of Schedule X is to provide the terms to a customer for installing gas distribution facilities for gas service at a particular premises. Schedule X provides these terms for residential, commercial, and industrial customers. Included in these terms is the methodology by which a customer will financially contribute to the cost of construction of the distribution facilities above a certain threshold based

on the estimated margin. The amount that a customer must pay toward the cost of the construction of distribution facilities is known as a "Construction Contribution." The dollar credit that may be available to a customer to offset the cost of distribution facilities to a new premises is known as a "Construction Allowance" or "Line Extension Allowance." I will refer to Line Extension Allowances as "LEAs" in my testimony. The Company's Schedule X that determines the LEA must be approved by the Public Utility Commission of Oregon (the "Commission"). The administration of a Commission-approved tariff for the extension of service to new customers allows the Company to efficiently serve customers by having a standardized set of terms for customers to rely on when they choose to join NW Natural's system.

Generally, the amount of the LEA provided in a utility's tariff is designed to be a short-hand calculation that reflects the amount of investment that a utility can make to add a new customer. This is reflected in OAR 860-021-0050(1), which states: "Each gas utility shall furnish, a gas service from the gas main adjacent to the customer's premises to and including the meter. Each gas utility shall develop, with the Commission's approval, a uniform policy governing the amount of service extension that will be made free to connect a new customer. This policy should be related to the investment that can prudently be made for the probable revenue."

Currently, NW Natural's Schedule X tariff provides an LEA for residential customers equal to 4.0 times the customer's anticipated annual margin. Based on a customer that uses 531 therms annually, that customer would be entitled to an $1,850 LEA. As I will describe more below, if the estimated costs of construction

exceed that amount, NW Natural will require potential customers to pay a Construction Contribution for the difference between the LEA and the estimated construction costs, grossed up for tax. Commercial and Planned Developments will use at a minimum 5.0 times margin to calculate the LEA. If construction costs are expected to exceed $250,000, then an additional discounted cash flow analysis is also performed.

Q. Please describe the change to the Company's LEA in the Company's last general rate case, UG 435.

A. In NW Natural's last rate case, the Commission modified the Company's LEA to a methodology based on a margin multiplier that phased down over three years. The Commission stated:

> We find it appropriate to implement a reduction to the LEA that is based on a previously used methodology that strikes a balance between drastically reducing the LEA and moderating any adjustment. We accept CUB's proposal regarding the LEA, in part, by ordering the company to adjust its LEA to reflect a five times the annual margin approach, comparable to the methodology the company used prior to its current Schedule X. Specifically, we find that the amount of $2,300, as produced by the company in response to Bench Request 7, strikes an appropriate balance. We find that the amount ordered is reasonable and strikes an appropriate balance of the competing interests we describe in this order.[2]

As such, beginning November 1, 2022, a customer would receive an LEA equal to 5.0 times their estimated annual margin. Beginning November 1, 2023, the LEA decreased to 4.0 times annual margin. Beginning November 1, 2024, the LEA will

[2] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 435, Order No. 22-388, at 51 (Oct. 24, 2022).

decrease to 3.0 times annual margin, absent a change in this rate case proposed in the Direct Testimony of Gregg H. Therrien.[3]

Q. The Commission specifically referred to an LEA amount of $2,300. What does that amount represent?

A. The Commission approved an LEA of $2,300 in the Order, which represents 5.0 times the annual margin of a new customer expected to use 531 therms.

Q. Has the Company provided an LEA of $2,300 to all new residential customers regardless of their expected margin?

A. No. Under a margin multiplier approach, the Company estimates the annual margin generated from a new customer based on their expected usage and multiplied that margin by 5.0 times. However, given the Commission's view that $2,300 was a reasonable amount, the Company capped its LEA at $2,300. In other words, even if a customer's expected usage would generate more than $2,300 using a 5.0 times margin multiplier, the Company did not provide an LEA higher than that amount for customers seeking service after November 1, 2022. The Company has taken this same approach using the 4.0 times margin multiplier since November 1, 2023, by capping the LEA at $1,850.

Q. How does the Company develop the LEA for potential customers?

A. In order to estimate annual margin, the Company collects estimated annual usage from each new applicant for service. Estimated usage is based on a variety of equipment and premises attributes, such as square footage, age of premises,

[3] NW Natural/1900, Therrien/15.

number of bedrooms, and equipment type. The equipment and premises attributes are captured for each customer, and an estimated usage and margin calculation is performed. As I explained above, if the estimated annual margin multiplied by the multiplier in effect is higher than the specified cap (i.e., $2,300 when the LEA was 5.0 times margin), then the LEA for that customer is reduced to the cap. It is important to note the LEA step down and cap are only for residential customers. The Commercial customer LEA is based on 5.0 times margin, with no step down and no cap.

Q. Please describe the Company's process for estimating construction costs for residential customers.

A. Generally, the Company uses the average construction costs from the prior year to estimate construction costs for residential customers. Historical costs are segmented by the type of residential service lines. The different residential service line segments include single-family new construction service lines, new construction spot-lot service lines, and conversion service lines. Single-family new construction service lines are associated with planned development neighborhoods. New construction spot-lot service lines are associated with new construction not associated with a planned development, and conversion service lines are for existing premises that choose to add natural gas service. Each year, the average costs of all residential connections are computed and applied to the appropriate type of service. For instance, a single-family new construction premises will use the historical average construction costs for a single-family new construction service line. A new construction spot-lot premises will use the

historical average construction cost for a new construction spot-lot service line, and a conversion premises will use the historical average construction cost for a conversion service line. Costs include the service line, meter, permit, and indirect materials. These costs are reviewed and analyzed annually.

If extraordinary construction conditions exist at the premises, such as extreme rocky conditions along the main and service line route, if the connection must be made from a high pressure main, if the service line length is greater than 300 feet, or the extension requires a railroad, bridge, or other non-standard crossing permit, then a site-specific estimate will be performed. All main extension costs associated with a new construction spot-lot or conversion will involve site-specific cost estimates. All commercial service lines require a site-specific estimate.

Q. How often does the Company update its construction costs?

A. The Company annually updates its construction costs. As mentioned previously, all historical construction costs from the prior year are calculated and segmented by single family new construction services, new construction spot-lot services, and conversion services. Each of these segments share attributes that uniquely impact construction costs.

Q. Please describe the process for a new customer who is requesting that gas service be extended to their premises.

A. The process will vary by applicant type, as new applicants can be builders representing planned developments, new construction spot-lot applicants, conversion applicants, and commercial applicants. The process will vary by

premises type and market segment. For conversions, a request for gas availability for an existing single-family residence may be received by phone, email, or the NW Natural website. An address is provided, and geo-spatial data is used to determine the location of the property to distribution facilities. An evaluation is then performed to determine costing methodology. As long as a premises does not have rocky soil conditions, is not connecting to a high-pressure main, has a service length less than 300 feet, and does not have a railroad or creek crossing, then the premises will use historical costs as a basis for construction cost. Otherwise, a site-specific estimate will be performed. At this point, the customer is provided a quote, which is valid for 30 days on a verbal basis, and 60 days if written. A signed service agreement is required to initiate the construction process, and the customer must pay the Construction Contribution. The service will be installed once all construction permits are received and utility locates are marked.

New Construction spot-lot applicants are similar to conversion applicants in that their proposed building is reviewed for the same criteria. The builder is responsible for installing NW Natural provided conduit for the service pathway. There are no service length restrictions because of the customer provided pathway. For new residential construction planned developments, NW Natural designs its natural gas distribution facilities alongside electrical distribution facilities to utilize the same open trench. If a main extension to serve the planned development is required, then a site-specific estimate will be performed for the approach main extension. If no approach main extension is required, then the designed footage is used with the historical system default costing to generate

construction costs for the distribution facilities. The number of buildable construction lots are defined by the design provided by the developer or civil engineer. Historical average costs are used for the single-family new construction services. The LEA is calculated using estimated usage of the entire development using current times margin and cap for each service.

For commercial applicants, all requests are estimated on a site-specific basis. The projected therm load is calculated using The North American Industry Classification System ("NAICS") code associated to the applicant, square footage of the building, and a historical coefficient of usage based on the NAICS code. A 5.0 times margin calculation is then performed, with no construction allowance cap. If construction costs are estimated to exceed the LEA, then a customer contribution is required for the difference, grossed-up for tax. According to Census.gov, the NAICS code definition is the following:

> "The North American Industry Classification System (NAICS) is the standard used by Federal statistical agencies in classifying business establishments for the purpose of collecting, analyzing, and publishing statistical data related to the U.S. business economy."

New construction spot lot quotes are held open for six months because of the lead time of building a house. New construction planned development and commercial quotes are held open for a year given the complexities of these projects.

Q. Are there different methodologies for determining the line extension allowances for residential and commercial customers?

A. Yes.

Q. Please explain the difference.

A. As explained earlier, the residential construction allowance is based on a specified margin multiplier with a cap. For commercial applicants, Schedule X provides that "the Company will perform an investment analysis for each installation to determine the amount of any [LEA]. At a minimum, the [LEA] will equal 5.0 times the annual margin revenue that is estimated to be generated from the operation of natural gas-fired equipment to be installed at the service address." If the estimated construction costs exceed $250,000, then an additional investment analysis will also be performed to ensure that the contribution generated from the 5.0 times annual margin sufficiently ensures project profitability and does not negatively impact ratepayers. An additional contribution will be required if the investment analysis shows it is necessary. If the investment analysis shows favorable results, then the project may proceed under the 5.0 times margin methodology.

Q. Please explain how the Company performs an investment analysis for commercial customers and how it compares to 5.0 times the annual margin revenue.

A. The investment analysis referenced above utilizes a discounted cash flow model to estimate net present value ("NPV") and present value of revenue requirement ("PVRR"). This model evaluates the cash flow and accounts for capital spend, operational and maintenance expenses, expected margin, and customer contribution from the 5.0 times annual margin. If PVRR from the discounted cash flow analysis is positive, then an additional contribution will be required. If the

results are favorable, then the project may proceed under the 5.0 times margin methodology.

Q. The tariff states that "[a]t a minimum, the Construction Allowance [for commercial and planned developments] will equal 5.0 times the annual margin revenue . . . ." How does the Company interpret the phrase "at a minimum" in this context?

A. To be clear, the Company will not provide more than 5.0 times margin to commercial or planned development customer. The phrasing "at a minimum" is not intended to mean that NW Natural will provide more than 5.0 times margin. Further, residential new construction planned developments are evaluated using the current 4.0 times margin, and not the 5.0 times margin mentioned in the tariff. We recognize this is confusing phrasing and will clarify this portion of the tariff in our compliance filing with this rate case.

Q. Please describe the Company's process for estimating construction costs for commercial customers.

A. Commercial customers require a site-specific estimate. Site-specific estimates require an estimator to visit the premises and estimate the required time, materials, and equipment needed to install the service line.

Q. Please state how many residential line extension allowances have required the new customers to contribute to construction costs over each of the last five years.

A. Please see NW Natural/4101, Zaubi, and Table 1 below. Nine percent of service lines required contributions in 2018. In 2023, 17 percent of service lines required

contributions. Total contribution dollars grew 164 percent, from $479,836 to $1,267,428.

Table 1

Year	Line Extension Count	Count Customer Contributions	% Requiring Contributions	Total Contributions
2018	7,789	678	9%	$479,836
2019	7,642	645	8%	$482,120
2020	7,034	706	10%	$782,478
2021	6,992	670	10%	$884,886
2022	6,284	718	11%	$902,424
2023	4,395	732	17%	$1,267,428
		Contribution Increase 2018-2023---------->		164%

Q. Why does the Company believe that more contributions have been required?

A. Higher, more frequent customer contributions are a result of a lower line extension allowance combined with higher construction costs. Higher construction costs have been driven primarily by jurisdictional restoration requirements. From 2019 through 2022, asphalt costs, which is a large component of restoration costs, grew 137% for conversion services, and 98% for spot-lot services. General inflation only accounts for a portion of those cost increases. Prior to 2018, municipalities, in general, only required a T-cut in the road and approximately 25 square feet of restoration. Post 2018, requirements quickly changed to include 100 to 500 square feet of surface area restoration, plus CDF (Control Density Fill) and Grind & Inlay.

Q. Does the Company keep records of how many potential new customers have received a quote from NW Natural, and ultimately, decided not to join NW Natural's system?

A. Yes. Since April of 2020, there are 4,569 potential new customers who decided not to proceed with joining NW Natural's system.

Q. What happens if the actual construction costs are lower or higher than the estimated construction costs?

A. Given the very nature of construction work there will be a high variability of job types and site conditions, which may lead to volatility between an estimate and actual costs. Even jobs that have a site-specific estimate are subject to higher than estimated construction costs. An estimator may not truly know the site conditions, such as rocky soil, until construction commences. Ultimately the Company honors the signed agreement with the customer, and these costs are included in plant whether or not construction costs are higher than estimated. In the case of a site-specific estimate where actuals come in lower than the estimate, the customer will be refunded the difference to the extent there was a contribution required.

Q. How do you verify that existing customers are not harmed by construction costs for line extensions that exceed the estimated costs?

A. There will always be jobs where actual construction costs are higher than estimated costs. As mentioned previously, the Company honors the signed agreement. However, referring back to NW Natural/4101, Zaubi, when evaluating the total work orders by year using a 25-year discounted cash flow methodology,

the net present value for the portfolio of customers is positive, and present value of revenue requirement is negative, indicating the portfolio of customers do not create a burden for existing rate payers. Even to the extent that there are some outliers (i.e., higher cost than estimated), there are sufficient cases where the costs come in below the indicated LEA. Further, see attachment NW Natural/4102, Zaubi. Eighty-three percent of these work orders have LEAs higher than needed compared to the construction cost. In other words, the calculated LEA exceeded the estimated construction costs, and therefore the existing customers would have benefitted more due to the addition of those customers.

III. COALITION'S RECOMMENDATIONS

Q. Did the Coalition analyze the Company's line extension allowances?

A. Yes, the Coalition argues that NW Natural "billed costs to ratepayers for residential line extensions that exceeded its approved Service Line Extension Allowance."[4] The Coalition argues that any new premises construction costs that exceed the line extension allowance should be disallowed.[5] In making this argument, the Coalition asserts that the Company's contribution to main line extensions "can be virtually unlimited."[6] Specifically, the Coalition argues that $2,222,531 of construction costs incurred in 2023 should be disallowed because those costs exceeded the individual customer allowances.[7] The Coalition also argues that the

[4] Coalition/100, Cebulko/37.

[5] *Id.*

[6] *Id.* at 41.

[7] *Id.* at 43.

Company's work orders for each individual line extension allowance are unclear.[8] Finally, the Coalition states that it is also investigating the Company's non-residential line extension allowances, and expects to address the issue in Rebuttal Testimony.[9]

Q. Please describe the Coalition's methodology and approach for calculating this proposed disallowance.

A. The Coalition first subtracts the customer contribution from the total cost of each 2023 work order. Second, the Coalition then subtracts $2,300 (i.e., the LEA) from the result of subtracting the customer contribution from the total cost for each work order, which the Coalition calls "Overage". If this calculation for any work order results in a negative value, then the result for that work order is given a zero. All the "Overages" for the 4,395 work orders in 2023 are then summed up, for a total of $2,222,531.

Q. Was the Company able to determine which extensions the Coalition has proposed for disallowance?

A. Yes. There are 833 work orders the Coalition has proposed for disallowance. This is 19 percent of the total.

Q. How does the Company respond to this proposed disallowance?

A. First, as described in the above testimony, we follow our Tariff Schedule X for all new customer additions. We have a detailed process to update our construction costs annually to ensure we are providing reliable construction quotes that

[8] *Id.* at 40.

[9] *Id.* at 45.

customers can rely on to purchase natural gas appliances. By isolating single construction costs that went over their reasonable estimate, the Coalition is evaluating prudency based on hindsight. As I explained earlier in my testimony, we endeavor to provide accurate estimates for construction. Simply because certain construction costs go over their estimate does not mean that the Company's actions were *de facto* imprudent.

Second, because we engage in thousands of new customer additions each year, there will always be construction costs that are above and below the estimates that we provide. This is the reality of being in the construction business. This is also why the Company reviews the cost/benefit of new customer additions based on a portfolio approach in any given year. To the extent there were 833 new customer additions that ultimately cost more than the Company's estimated construction costs when signing a service agreement, that also means that the remaining 3,562 customer additions offset those costs, assuming that the present value of revenue requirement for the portfolio is negative, which it is. The Coalition's approach is one-sided and punitive and does not attempt to recognize the benefit of the 3,562 other customer additions.

Third, the Coalition has incorrectly calculated the purported overage. Some of the work orders that the Coalition has proposed for disallowance are from the work orders that were initiated before the LEA was changed on November 1, 2022. There is always a delay between the time customers sign a service agreement and when the construction actually occurs. At the time the Company entered into service agreements with new customers in 2022, the LEA was still $2,875. As

such, the calendar year 2023 for new plant placed in service for residential customer additions would include LEAs from 2022. Additionally, there are work orders included in the 2023 residential connections that include multi-family residential premises. Those premises are captured in a single work order, but would have multiple meters associated with them, and therefore, be entitled to an LEA for each new customer addition. When accounting for theses corrections, this creates an overestimate in the Coalition's proposed disallowance by $320,590.

Q. The Coalition appears to make a distinction of line extension allowances between service line extensions and main line extensions. How does the Company respond?

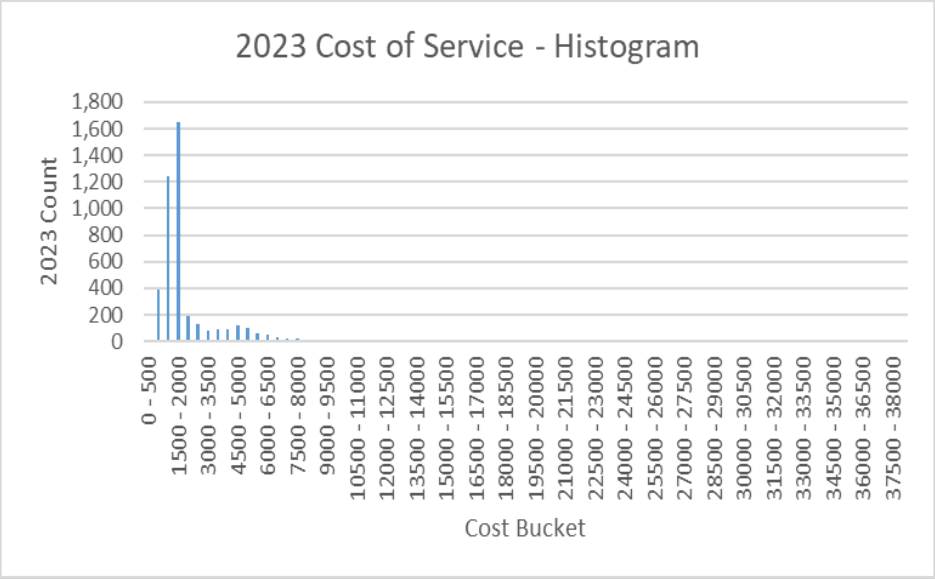
A. All main extension costs are evaluated in the LEA/Customer Contribution calculation, including new construction planned developments, new construction spot-lots, and conversions. Main extensions for new construction planned developments are referred to as system expansion. Main extension costs allocated to individual services lines for Conversions and New Construction Spot-lots are shown in column L in NW Natural/4101, Zaubi.

System expansion costs are typically not allocated to particular service lines on a connection-by-connection basis for each customer addition. Rather, new construction planned developments are evaluated at the project level using an NPV/PVRR analysis and maintaining the current limit of 4.0 times margin allowance for the project. New construction planned developments can include hundreds of premises, and take years for all service lines to go into service. To take a snapshot in time and allocate completed system expansion costs to only a

fraction of actual service lines in service would be misrepresenting costs on a per service line basis. Instead, the Company performs the analysis for the entire development, and then individually applies LEAs to each new premises addition.

Q. The Coalition argues that the Company's work orders were incorrect.[10] How do you respond?

A. As established in the earlier testimony, there may be time entry errors, or miscoding of invoices to wrong work orders in some of the data set. However, this is the exception and not the rule. See the histogram below and in NW Natural/4102, Zaubi. Ninety-nine percent of 2023 work orders are below a total cost of $10,000, and 82 percent of all orders are between $1,000 and $5,000, which suggests costs are approximately in range of expectations, and therefore can conclude are reasonably accurate. If there were widespread work order errors, the distribution would be much more dispersed than observed for 2023.



[10] *Id.* at 40.

Q. Does this conclude your Reply Testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibits of Jeffrey M. Zaubi

SCHEDULE X ADMINISTRATION
EXHIBITS 4101 - 4102

June 4, 2024

EXHIBIT 4101-4102– SCHEDULE X ADMINISTRATION

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Exhibit 4101 – UG 490 OPUC DR 138 Attachment 1 – Amended (Excel)

Exhibit 4102 – Calculated LEA Compared with Estimated Construction Costs (Excel)

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Jeffrey M. Zaubi

SCHEDULE X ADMINISTRATION
EXHIBIT 4101

This exhibit is being filed in its native, Excel format.

June 4, 2024

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Jeffrey M. Zaubi

SCHEDULE X ADMINISTRATION
EXHIBIT 4102

This exhibit is being filed in its native, Excel format.

June 4, 2024

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Reply Testimony of Scott S. Johnson

LONG-TERM HEDGING
EXHIBIT 4200

REDACTED

June 4, 2024

EXHIBIT 4200 – REPLY TESTIMONY – LONG-TERM HEDGING

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and position at Northwest Natural Gas Company dba NW Natural ("NW Natural" or the "Company").

A. My name is Scott S. Johnson and I am Director of Gas Supply at NW Natural.

Q. Please describe your education and employment background.

A. I have a Bachelor's degree in Accounting and started my career working at a public accounting firm where I focused on auditing utilities. I have worked at NW Natural for 13 years in various roles including financial reporting, gas and regulatory accounting and gas supply. I have worked in gas supply for about 10 years.

Q. What is the purpose of your Reply Testimony in this proceeding?

A. The purpose of my Reply Testimony is to respond to the Opening Testimony of Anna Kim on behalf of Staff for the Public Utility Commission of Oregon ("Staff") concerning Staff's proposal to establish a sharing mechanism for gas supply hedges that exceed three years in duration (Staff/1100, Kim).

Q. Please summarize your Reply Testimony.

A. In my testimony, I:

- Provide relevant background regarding long-term hedges, the Commission's previous long-term hedging orders, and the incorporation of stipulated long-term hedging guidelines into the Commission's Natural Gas Portfolio Development Guidelines;
- Provide relevant background regarding increased pricing and volatility at Pacific Northwest gas trading hubs; and

- Respond to Staff's policy proposal, which the Company believes would require it to absorb 10 percent of the "above market"[1] costs for those long-term hedges that exceed either five percent of "total [gas] costs,"[2] or gas volumes.[3]

II. BACKGROUND

Q. Please define hedging.

A. Hedging is defined as reducing risk. It includes activities that reduce risk or that convert one type of risk to another deemed more tolerable. To qualify as hedging, an activity should be expected to produce a measurable offset to risk relating to an asset, liability, committed transaction, or probable forecasted transaction. A "long-term" hedge is considered to be three years or longer.

Q. Please explain how hedging benefits customers.

A. The use of hedging strategies and derivative structures is intended to allow the Company to reduce commodity price, exchange rate, and interest rate risks (market risks). NW Natural's internal policy is intended to prevent speculative risk. Speculative risk is defined as any risk that is engaged in for reasons other than to reduce market or credit risk, including transactions engaged in solely for the purpose of profiting from market movements. Hedging activities are considered speculative if they increase the Company's exposure to market risk. Speculative risk also includes normal market making where the expectation is simply to profit

[1] In her testimony, Ms. Kim defines "above-market" costs as the premium paid for the hedge that is above the forward price curve for the natural gas market. Staff/1100, Kim/7.

[2] Staff/1100, Kim/6.

[3] NW Natural/4201, Johnson.

from the bid-ask differences. Proper hedging using derivatives should decrease net exposures of the Company to market risk. Hedging with a goal of reducing market risk and avoiding speculation benefits utility customers by helping to provide price stability.

Q. Please summarize the Commission's previous decision concerning long-term hedges.

A. The Commission has considered long-term hedging in the past. In NW Natural's 2014 Integrated Resource Plan ("IRP"), the Company proposed to increase its long-term hedging. Staff opened an investigation into that specific issue (UM 1720). During that investigation, the parties "engaged in several workshops to address a variety of issues related to the LDCs' use of long-term hedges."[4] However, "efforts to draft uniform guidelines proved unsuccessful due to the diversity in available hedging instruments and the optionality of the duration and timing of hedges."[5] The Commission "accept[ed] the parties' unanimous conclusion that the diversity and optionality of hedging instruments preclude the ability to develop a uniform set of principles."[6] Instead of developing a uniform set of principles, the parties agreed that a natural gas utility may choose to meet with stakeholders to explain a long-term hedge and stakeholders may provide written comments within 30 days of such a meeting.[7]

[4] *In the Matter of NW Natural Gas Co, dba NW Natural, Investigation into Long-Term Hedging Policy*, Docket No. UM 1720, Order No. 18-019, at 2 (Jan. 18, 2018).

[5] *Id.*

[6] *Id*.

[7] *Id.* at 2.

Q. Was this meeting-and-comment process adopted by the Commission?

A. Yes. In 2018, the Commission approved changes to the Natural Gas Portfolio Development Guidelines that incorporated the meeting-and-comment process summarized above.[8] The Natural Gas Portfolio Development Guidelines list what Oregon natural gas utilities should consider in assembling their natural gas portfolio, as well as a process for stakeholder review and the development of annual Purchase Gas Adjustment ("PGA") filings to recover commodity costs. In the order incorporating the meeting-and-comment process for long-term hedges, the Commission accepted Staff's recommendation to not adopt "a 'one size fits all' approach"[9] to long-term hedges. The Commission agreed with Staff that such a narrow approach is not appropriate given "the diverse hedging instruments available and the optionality of the duration and timing of hedges."[10] Therefore, any long-term hedge should be evaluated on its own merits, not through generic rules or rate sharing mechanisms.

Q. Has NW Natural used the meeting-and-comment process concerning long-term hedges?

A. Yes. The Company has used the process once in January 2024 in response to a specific fundamental market opportunity at the Sumas trading hub. Due to

[8] *In the Matter of the Public Utility Commission of Oregon, Modifications to Natural Gas Portfolio Development Guidelines*, Docket No. UM 1286, Order No. 18-144 (May 1, 2018).

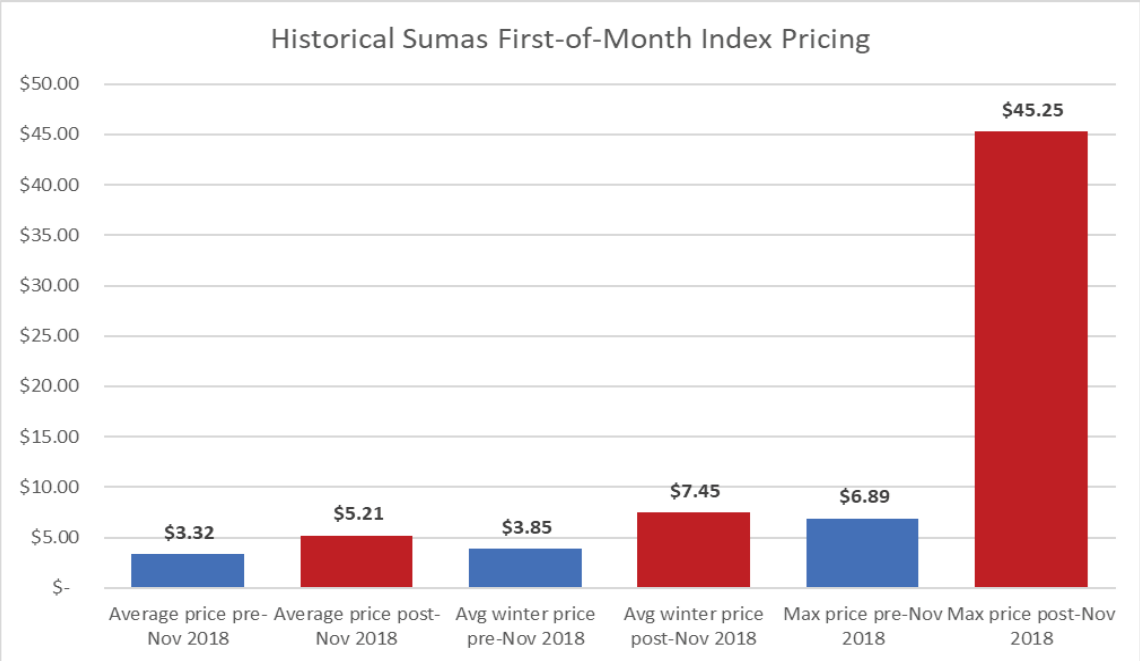
[9] *Id.* at Attach. A, at 3.

[10] *Id.*

changing market conditions, however, the Company ultimately decided against entering the long-term hedge.

Q. Please explain the increased pricing environment at Pacific Northwest gas trading hubs that you have recently observed.

A. The supply-demand balance of western natural gas markets from which NW Natural procures gas has become much more volatile, exposing market participants to much higher prices. Since the long-term hedge NW Natural previously discussed with stakeholders was at Sumas, I will focus on the Sumas market in this testimony. As shown in the table below, since November 2018, Sumas first-of-month index prices averaged $5.21/Dth annually, $7.45/Dth in the winter, and peaked at $45.25/Dth. For the 10 years prior to this most recent five-and-one-half year period, Sumas first-of-month index prices averaged $3.32/Dth annually, $3.85/Dth in the winter, and peaked at $6.89/Dth.



First-of-month index prices do not tell the full picture as daily pricing has seen even higher prices with average daily Sumas prices peaking at $159.27/Dth in 2019, $46.29/Dth in 2022 and $21.77/Dth in 2024.

Q. Please explain the potential benefits of long-term hedges to mitigate the risk of increased customer rate volatility.

A. Customer bills experience less volatility when hedging is part of the portfolio. As longer-term hedges are layered into a portfolio, it further decreases customer bill volatility. Most of the bill volatility reduction is accomplished with a portfolio of hedges up to three years in duration. There can be fundamental market instances when it would be beneficial to hedge longer than a three-year duration. Since Order No. 18-144 was issued, however, NW Natural has only executed hedges that were three years or less.

More recently, the supply-demand balance in the Pacific Northwest has been tightening, leading to higher volatility and prices as I just discussed . **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[redacted] **[END CONFIDENTIAL]**

III. RESPONSE TO STAFF'S LONG-TERM HEDGING PROPOSAL

Q. Before addressing the merits of Staff's long-term hedging proposal, please clarify whether NW Natural is seeking either cost recovery of any long-term hedges or policy changes concerning long-term hedges in this proceeding.

A. NW Natural is not seeking cost recovery of any long-term hedges in this proceeding, nor is it seeking any policy changes concerning long-term hedges. Any costs associated with purchased gas, including any potential long-term hedges, are recovered through the PGA, not a general rate case. In addition, NW Natural has not executed a long-term hedge over the last 10-plus years. The proposed long-term hedge recently discussed with stakeholders would not meet Staff's proposed thresholds for inclusion in its proposed cost-sharing mechanism because that hedge would not have exceeded either five percent of total gas costs or five percent of total gas demand.[11]

[11] Staff has been inconsistent as to whether its proposed threshold is five percent of total gas costs or five percent of total gas volumes. Staff/1100, Kim/6 references total gas costs. Staff's response to a NW Natural data request references total gas demand. Confidential NW Natural/4201, Johnson.

Q. Do you believe it is appropriate to address long-term hedging in a general rate case proceeding?

A. No, I do not. It is inappropriate to design a cost-sharing mechanism for long-term hedges in this proceeding because the Commission has already found such hedges to be diverse and, therefore, ill-suited to generic rules or guidelines, as I have described in the previous section of my testimony. In addition, there are procedural issues with Staff's proposal. When NW Natural previously explored pursuing long-term hedges in its 2014 IRP, it led to dockets where all Oregon natural gas utilities, including Cascade and Avista, could participate (UM 1720 and UM 1286). From a procedural perspective, this is important because any generic cost-sharing mechanism approved by the Commission in this docket would likely be applied to Avista and Cascade as well. This docket, however, is a general rate case where other natural gas utilities do not typically intervene (and have not intervened in this particular case). Therefore, NW Natural does not believe it is appropriate to address long-term hedging here, particularly because it is not linked to a specific request for cost recovery or a policy proposal made by NW Natural.

Q. If Staff nonetheless decides to pursue long-term hedging in this proceeding, please explain its cost-sharing proposal.

A. Staff's proposal is not clear, and the Company is unsure how it would be implemented based on Staff's testimony and follow-up data requests. However, it is our understanding that Staff intends for the Company to absorb 10 percent of the "above market" costs of certain sized long-term hedges. In other words, Staff

would build in an automatic 10 percent penalty for long-term hedges that the Company enters into regardless of the underlying prudency of the hedge.

Q. Has Staff adequately explained what long-term hedges are subject to its sharing proposal?

A. No. Staff has not adequately explained which long-term hedges are subject to the sharing proposal. In testimony, Staff states that its sharing proposal would apply if the cost of long-term hedges exceeds five percent of forecasted gas costs.[12] In a response to a data request, Staff states that its sharing proposal would apply if long-term hedges exceed five percent of gas demand.[13] Therefore, it is not clear how the sharing proposal would apply or why Staff is inconsistent regarding its proposal. The Company understands this proposal to be limited to financial commodity hedges and not include foreign exchange or interest rate swaps, for example.

Q. Staff would require sharing of "above market"[14] costs. Is it clear why "above market costs" should be used?

A. No, it is not. For "above market" costs, it is important to recognize that natural gas markets are less liquid further out in the future and the premium is mainly driven by the liquidity of a specific market. We would expect a liquidity premium to be present in all long-term hedges, but that it would be larger in less liquid markets. The Company is having difficulty interpreting the intended signal from Staff of

[12] Staff/1100, Kim/6.

[13] Confidential NW Natural/4201, Johnson.

[14] Staff/1100, Kim/6.

proposing a penalty tied to the liquidity premium of a given natural gas market or why that liquidity premium should dictate how much NW Natural can recover from its customers in rates regardless of the underlying prudency of the hedge. Rather, Staff's proposal functions as an automatic 10 percent penalty on all long-term hedges.

Q. Is it clear how Staff's automatic 10 percent penalty balances the interests of the Company and its customers?

A. No. Staff does not explain how its automatic 10 percent penalty balances the interests of the Company and its customers. Put quite simply, if NW Natural's long-term hedge benefits customers, then the Company would recover 90 percent of the "above market costs" (i.e., the premium paid for the hedge that is above the forward price curve for the natural gas market). Staff makes no attempt to justify why an action to mitigate commodity cost volatility should not be allowed cost recovery if it can be shown to be a prudent decision.

Q. Is it clear why Staff is seeking to change established Commission policy on long-term hedges?

A. No. Staff has pointed to no changes in circumstance since the meeting-and-comment process was adopted in Order No. 18-144. Nor does it address why it is adopting a one-size-fits-all approach that both the Commission and stakeholders

considered during the long-term hedging investigation and then abandoned due to the diversity of long-term hedges.[15]

Q. Is it clear how Staff's proposal minimizes risk for customers?

A. No. Staff has failed to explain why its proposal incentivizes gas supply procurement that minimizes risk for customers. Contrary to its stated intention, Staff's proposal may in fact subject customers to greater risk by disincentivizing long-term hedges that promote rate stability.

Q. Did you seek clarification of Staff's proposal through data requests?

A. Yes, we did seek clarification, which was helpful in certain instances, but it confused other matters further. In NW Natural Data Request No. 10g, Staff clarified that: "The Company should enter into hedges only when the Company believes it is worth the risk of losing ten percent relative to the alternative of not hedging."[16] I would contend that as designed, there is no sharing of risk. The Company would simply take a loss for 10 percent of the "hedge premium", so there is no risk calculus at play. NW Natural would effectively incur a penalty for any long-term hedge executed.

In Staff's response to NW Natural DR 10j: "Staff assumes the Company would choose hedges that would have a neutral or positive financial impact to the

[15] *In the Matter of NW Natural Gas Co., dba NW Natural, Investigation into Long-Term Hedging Policy*, Docket No. UM 1720, Order No. 18-019, at 2 (Jan. 18, 2018).

In the Matter of the Public Utility Commission of Oregon, Modifications to Natural Gas Portfolio Development Guidelines, Docket No. UM 1286, Order No. 18-144 (May 1, 2018).

[16] Confidential NW Natural/4201, Johnson.

Company."[17] We concur with Staff's assumption and note that this proposal would never offer that outcome, since a penalty is a negative financial impact.

Q. Despite some aspects of Staff's proposal being unclear, do you believe you have a general understanding of what Staff is recommending?

A. Yes. Although certain details are unclear, it is apparent that NW Natural would simply take a punitive loss upon executing any long-term hedge, even if it were in the best interest of customers. Imposing a penalty would not incentivize the Company to execute long-term hedges, even when the transaction is in the best interest for customers. Instead, Staff's proposal would have the likely impact of causing the Company to never enter into a long-term hedge, exposing customers to long-term price risk.

Q. Staff states that it is making a proposal in response to a meeting that NW Natural called in January 2024 concerning long-term hedges. Please explain why NW Natural decided to call that meeting.

A. As was noted earlier in my testimony, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Q. How did Staff characterize that meeting?

A. Staff stated that it **[BEGIN CONFIDENTIAL]** [redacted]

[17] *Id.*

[redacted] **[END CONFIDENTIAL]**

Q. Do you agree with this characterization?

A. No. The volumes are stated in the Company's presentation. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

[18] Staff/1100, Kim/5.

Q. Despite your disagreement with Staff's characterization of the meeting, it nonetheless is the case that Staff felt that it could not evaluate NW Natural's hedging strategy and make a recommendation. Given Staff's findings, does it logically follow that Staff should make a long-term hedging proposal in this proceeding?

A. Not at all. As I have stated earlier in my testimony, NW Natural decided to not pursue the long-term hedge in question due to changing market conditions. Since NW Natural has not entered into a long-term hedge and, therefore, is not seeking cost recovery or policy changes regarding such hedges, Staff's proposal is unnecessary, especially given the Commission's previous findings that the diversity of long-term hedges precludes a one-size-fits-all approach. Moreover, even if NW Natural entered into that hedge, it would not meet the threshold set by Staff for inclusion into its proposed cost-sharing mechanism (i.e., it is less than five percent of both total gas costs and demand). While NW Natural appreciates the time and effort that Staff have spent on long-term hedges, its proposal is a flawed solution to a problem that does not currently exist.

Q. Does this conclude your Reply Testimony?

A. Yes, it does.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Exhibit of Scott S. Johnson

LONG-TERM HEDGING
EXHIBIT 4201

REDACTED

June 4, 2024

UG 490– PUC Responses to NWN Second Set of Data Request 10 with CONFIDENTIAL data and CONFIDENTIAL DR 16
Page 1

Date: May 9, 2024

TO:

Eric Nelsen
Northwest Natural Gas
220 NW Second Avenue
Portland, OR 97209

Lisa Rackner or Jocelyn Pease
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FROM: Anna Kim, Staff

OREGON PUBLIC UTILITY COMMISSION
Docket No. UG 490 – NWN Data Request No 10.

Data Request No 10:
Referring to Staff/1100, Kim/5, "Staff proposes 90/10 sharing on costs of long-term hedges that exceed five percent of total gas purchases."
a. Is the five percent proposal "per year"? Please explain.
b. Is the five percent threshold based on individual long-term hedges or cumulative long-term hedges? Please explain.
c. Is the five percent threshold based on an annual total gas purchase calculation? Please explain.
d. Please provide Staff's analysis for determining the threshold of five percent of total gas purchases.
e. Staff/1100, Kim/7, Line 4 states that Staff "proposes that long-term hedges above five percent of total retail load be presumed reasonable and prudent by evidence of the fact that the Company bears ten percent of the "above market" cost of the contract." Please explain whether Staff's proposed "five percent" threshold would be cost based, load based, or otherwise. Please explain.
f. Please provide an example of how this sharing is calculated over duration of a long-term hedge.
g. How does having the Company absorb 10% of costs of a long-term hedge help ensure that the Company acts in a manner that is in the best interests of both customers and the utility?
h. Please provide any long-term analysis of gas markets relied on by Staff to develop its proposal.
i. Please provide Staff's analysis for determining the 10% sharing level that the Company would absorb under Staff's proposal.
j. Please provide Staff's analysis of the financial impact on the Company of this Staff proposal.
k. Please provide Staff's proposed regulatory process for the 90/10 long-term hedge sharing mechanism.
l. Given that the Company procures gas supplies at several supply points with highly variable pricing, how does this proposal account for pricing at these specific basins?

UG 490– PUC Responses to NWN Second Set of Data Request 10 with CONFIDENTIAL data and CONFIDENTIAL DR 16
Page 2

m. Given that prices at AECO are often around one-third of Sumas prices, how does triggering this mechanism based on price make more sense than triggering based on volumes or another metric?

CONFIDENTIAL Staff Response No 10:

a. Yes. Five percent of forecasted gas demand.
b. Cumulative of hedges on an annual basis in which they are executed.
c. See a.
d. Staff does not believe the sharing mechanism is necessary to protect customers for cumulative annual hedges that are less than five percent of purchased gas costs. Cumulative annual hedges below this amount will have no presumption of reasonableness and no sharing.
e. See a.
f. The above-market cost would be calculated at time of purchase for the entire contract. The above-market cost would be paid over time within the PGA for each year these hedges are executed.
g. Sharing the costs of the hedge will provide some incentive to the Company to align the interests of the Company and customers. The Company should enter into hedges only when the Company believes it is worth the risk of losing ten percent relative to the alternative of not hedging. Staff chose a percentage value equal to the PGA sharing alternative of 10 percent to align those values.
h. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**
i. As noted in (g), Staff proposes ten percent sharing to be consistent with sharing of other costs in the Purchased Gas Adjustment (PGA).
j. With 90/10 sharing, Staff assumes the Company would choose hedges that would have a neutral or positive financial impact to the Company.
k. Staff proposes using the existing annual PGA process.
l. Costs can be compared to the basin in which the hedge is placed.
m. A percentage of expected load has a higher likelihood of transparency than on market forecasts.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 490

NW Natural

Reply Testimony of John D. Frankel

PROMOTIONAL ACTIVITIES
EXHIBIT 4300

June 4, 2024

EXHIBIT 4300 – REPLY TESTIMONY – PROMOTIONAL ACTIVITIES

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and position with Northwest Natural Gas Company dba NW Natural ("NW Natural" or "Company").

A. My name is John D. Frankel. I am the Director of Marketing. As the Director, I am responsible for overseeing various administrative functions at NW Natural involving marketing, customer service and trade ally development. In my role, I am accountable for strategic planning, leadership of the marketing teams, and development of residential, industrial, and commercial marketing programs.

Q. Please summarize your educational background and business experience.

A. I received a Bachelor of Science degree in Business Administration from Oregon State University in 1986. I have been employed by NW Natural since 2005 and have been in my current position since March 2022. During my career, I have held various management positions in marketing, merchandising, operations, purchasing, and customer service.

Q. What is the purpose of your Reply Testimony?

A. The purpose of my Reply Testimony is to respond to adjustments related to promotional and marketing activities proposed by Public Utility Commission of Oregon Staff ("Staff") witness Luz Mondragon, and Coalition[1] witnesses Nora Apter of the Oregon Environmental Council ("OEC") and Meredith Connolly of Climate Solutions.

[1] The Coalition includes the Coalition of Communities of Color, Climate Solutions, Verde, Columbia Riverkeeper, Oregon Environmental Council, Community Energy Project, and Sierra Club.

Q. Please provide a summary of your testimony.

A. In my testimony, I will:

- Review the promotional expenses that NW Natural has withdrawn from this rate case in response to data requests;
- Remove further promotional expenses in response to parties' Opening Testimony; and
- Explain why the remaining costs challenged by Staff and the Coalition are prudent and beneficial for customers and should be recoverable under the Commission's rules.

II. BACKGROUND REGARDING PROMOTIONAL ACTIVITIES AND CONCESSIONS

Q. Please review the definitions of promotional activities and concessions.

A. The Commission's rules distinguish between promotional activities and promotional concessions. Promotional activities are those actions intended to increase or prevent a decrease of energy or service used by prospective customers and inducing a person to use the energy utility's service instead of a competing form of energy. [2] A promotional concession is consideration (usually in the form of a rebate or discount) granted by the utility to any person with the object of inducing that person to use the utility service. [3]

[2] OAR 860-026-0010.

[3] OAR 860-026-0015.

Q. For context, please provide your understanding regarding the Commission's rule governing promotional activities and concessions.

A. I understand that OAR 860-026-0020(1) provides:

> All promotional activities and concessions shall be just and reasonable, prudent as a business practice, economically feasible and compensatory, and reasonably beneficial both to the energy or large telecommunications utility and its customers. The cost of promotional activities and concessions must not be so large as to impose an undue burden on the energy or large telecommunications utility's customers in general and must be recoverable through related sales stimulation within a reasonable time.

Q. Did NW Natural consider these requirements when determining what promotional activities to include in this case?

A. Yes. As I explain below, the expenses included in this case benefit the Company and its customers in a variety of ways. The costs are modest, consistent with the amounts NW Natural has included in past rate cases, and support the Company's provision of safe and reliable service and growth.

Q. Did NW Natural seek to recover expense associated with promotional concessions in this case?

A. No. The Company has removed expense for promotional concessions from its request for cost recovery. Prior to filing this case, NW Natural removed expense from account 10178 for corporate identity, other contract work, and dealer relations in the amount of $151,363. The Company also removed $289,153 for promotional activities and advertising campaigns related to customer acquisition.

Q. Through discovery, did NW Natural identify any promotional activities and concessions expense that should be removed from its initial request?

A. Yes. Those expenses were described in the Company's response to Coalition Data Request No. 72, and total $41,014.70 of Test Year expense.

Q. Is the Company accepting any of the proposed adjustments recommended by Staff and the Coalition?

A. Yes. As detailed below, we have identified other transactions of which the Company will not seek cost recovery.

Q. Please provide the total dollar amount that NW Natural is proposing to remove from cost recovery associated with promotional activities, as updated in this Reply Testimony.

A. As explained below, NW Natural is removing $118,897 in promotional activities (after Oregon allocation).

III. REPLY TO STAFF AND THE COALITION

Q. Please summarize Staff's position regarding the Company's promotional activities.

A. Staff witness Mondragon reviewed the Company's Customer Service and Information; Sales Expense (Customer Service) in FERC Account Nos. 907-916, excluding 909 and 913 (advertising).[4] Staff comments that overall, expense in these categories have declined since 2021, and suggests that it may be the result of the Company incorporating the feedback received in the prior rate case and

[4] Staff/200, Mondragon/8.

making changes to charge to non-recoverable cost centers.[5] Staff proposed reductions to FERC Accounts 908 (Customer Assistance Expense) and 912 (Demonstration and Selling Expense), resulting in a proposed adjustment of $108,457 system-wide or $95,858 Oregon-allocated. Staff also proposed to further reduce the Test-Year Customer Service and Information Sales Expense by $5,810 to account for Staff's proposed Consumer Price Index ("CPI") escalation.

Q. Do you address the CPI escalation adjustment in your testimony?

A. No. The issue is addressed in the Reply Testimony of Company witness Mr. Davilla, NW Natural/3500, Davilla.

Q. Does Staff detail the expenses that are specifically proposed to be removed?

A. Yes. Staff's Figure 7[6] in its Opening Testimony has identified adjustments by the Company's cost center.

Q. What is Staff's rationale for the adjustment?

A. Staff asserts that customers receive little benefit from event sponsorships, Home Building Association fees, home tours, building industry events, and other related activities, and thus they do not satisfy the criteria for rate recovery under OAR 860-026-0020(1).

[5] Staff/200, Mondragon/13.

[6] Staff/200, Mondragon/15.

Q. In response to Staff, why do you generally believe that these activities benefit customers?

A. Resilience, comfort, and fuel choice are important considerations for Oregonians. Increasingly, customers seek natural gas service as a cost-effective way to heat their homes and water, cook, and in some cases drive backup power generation. Having reliable gas service offers the peace of mind that residents need in circumstances where power outages become more prevalent. As such, reasonable and prudent expenditures on promotional and marketing activities are the foundation of our support for the community of trade allies that assist our mutual customers and help to provide reliable energy service in the region.

Q. Please explain how NW Natural's support for its community of trade allies benefits customers.

A. Trade association support and the sponsorship of builder home shows benefits customers by providing them, as well as the general public, information about gas amenities. Additionally, community events provide an opportunity to educate our customers and the general public about the gas system, gas appliances, and NW Natural's decarbonization efforts.

These activities are much more complex than the terms marketing and promotion imply. They involve a varied assortment of stakeholders who engage NW Natural during the construction process, which includes builders, developers, HVAC contractors, fireplace dealers, plumbers, remodelers, architects, and engineers, as well as the actual commercial and residential end-use customers who are adding natural gas service.

It is important for the Company to maintain strong relationships with the various tradespeople who assist our mutual customers. Through NW Natural's engagement with these groups, the contractors and partners who collaborate with NW Natural are trained, properly insured, certified, and fully informed about NW Natural processes. Having a well-trained, fully informed network of independent trade partners (including new construction) is beneficial to NW Natural's customers.

Q. Upon further review of the transactions in Staff's adjustments, does NW Natural continue to seek cost recovery of all of the transactions?

A. No. The Company will no longer seek recovery of several transactions.

Q. Please summarize by cost center the transactions that NW Natural no longer seeks to recover compared to Staff/200 Figure 7.

A. Please see Table 1 below.

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TABLE 1

FERC	Cost Center	NWN Removed in Data Request	NWN to remove in NWN/4300	Total NWN to Remove	Mondragon Figure 7 reduction	Difference
908		**$1,995**	**$1,888**	**$3,883**	**$11,848**	**$7,965**
908	10102	$0	$540	$540	$3,682	$3,142
908	10103	$0	$0	$0	$47	$47
908	10161	$1,995	$1,348	$3,343	$8,119	$4,776
912		**$25,348**	**$11,801**	**$37,149**	**$96,610**	**$59,461**
912	10104	$5,000	$0	$5,000	$57,355	$52,355
912	10163	$20,348	$198	$20,546	$27,609	$7,063
912	10165	$0	$2,089	$2,089	$2,132	$43
912	10179	$0	$1,381	$1,381	$1,381	$0
912	10180	$0	$4,427	$4,427	$4,427	$0
912	10185	$0	$3,706	$3,706	$3,706	$0
		$27,343	**$13,689**	**$41,032**	**$108,458**	**$67,426**

In summary, Staff witness Mondragon's testimony asserts that $108,457 (from Test Year) should be excluded. Of that amount and from these cost centers, the Company has already committed to removing $27,343 in response to data requests in the case. Through additional review in response to Staff's Opening Testimony, the Company agrees to withdraw $13,689 from its filing. The total withdrawn from the filing is $41,032 (Oregon allocated).

Q. Please summarize the Coalition's position regarding the Company's expense associated with promotional concessions.

A. The Coalition notes that NW Natural has indicated that it does not seek to recover costs for any of its promotional concessions from customers, but argues that the

Company nonetheless seeks cost recovery for certain promotional activities.[7] The Coalition recommends a disallowance of $115,307 in costs associated with promotional concessions, which are comprised of the following:

- $23,000 in costs related to the Street of Dreams (in various Cost Centers and G/L accounts including Other Contract Work for $11,463, Corporate Identity for $6,154, Mileage Reimbursement for $648, Dealer Relations for $4,083, Misc accounts for $250) (all Oregon allocated);
- $19,300 (Oregon allocated) associated with showcasing natural gas products during home demonstration events, and for its meeting costs with homebuilders associations and the Building Industry Association; and
- $73,007 associated with promotional concessions that NW Natural disclosed in discovery were inadvertently included in its request and committed to removing from its request (Oregon allocated).

Q. Is the Coalition correct that NW Natural identified $73,007 of expense associated with promotional concessions that will be removed from the case?

A. No. It appears that the Coalition is including both the Base Year and the Test Year expense in its proposed adjustment. Only the Test Year expense will be removed, which totals $41,015. NW Natural is removing $41,015 from the Company's request for cost recovery.

[7] Coalition/200, Apter-Connolly/56.

Q. How do you respond to the Coalition's proposed adjustments concerning the Street of Dreams and demonstration and selling expense?

A. Although the Company provided an explanation justifying cost recovery for these expenses in response to discovery, the Company is removing from its request the roughly $23,000 in Street of Dreams-related expense in this rate case.

Q. Of the remaining transactions that the Coalition argued should not be recovered, how does the Company respond?

A. Of the $19,300 of costs the Coalition proposed to be removed as outlined in Coalition/209, Apter-Connolly, the Company agrees to remove $12,768 of the Oregon allocated amount, but disagrees with the remaining exclusions. One item, totaling $1,763 on an Oregon allocated basis ($1,995 on system basis) related to the outdoor gas pizza oven, is being double counted by the Coalition as this is already being excluded in adjustments the Company agreed to in Coalition DR 72.

After removing the double count, the Company believes that the three expense items totaling $5,552 actual or $4,897 on an Oregon allocated basis are justified. As explained in OPUC DR 334 and above in the response to Mondragon Figure 7, these expenses include $1,250 for membership in a Portland realtor association, $2,757 for an HVAC and hearth industry breakfast meeting, and $1,545 for catering for a builder trade group luncheon meeting that provided safety awards to homebuilders. All three expenses are important in building and maintaining the partnership and collaboration with the community of allies that serve our mutual customers. They are reasonable and prudent expenses that

should be recoverable. Please see Table 2 below for a breakdown of the Company's removal of transactions in response to the Coalition's testimony.

TABLE 2

Coalition challenges to Promotional Activities	NWN/4300 Remove from cost recovery	Coalition/200	Difference
Street of Dreams support	$22,448	$22,448	$0
subtotal	**$22,448**	**$22,448**	**$0**
Parade of Homes sponsor fee	$7,500	$7,500	$0
Salem Tour of Homes sponsor fee	$7,000	$7,000	$0
Realtor Assoc member fee	$0	$1,250	$1,250
Dealer breakfast meeting expense	$0	$2,757	$2,757
Builder safety award lunch meeting expense	$0	$1,545	$1,545
subtotal	**$14,500**	**$20,052**	**$5,552**
Gas pizza oven demo equipment (base year)	$0	$1,995	$1,995
Gas pizza oven demo equipment (test year)	$2,185	$2,185	$0
Gas tankless water heater demo equipment (base year)	$0	$19,998	$19,998
Gas tankless water heater demo equipment (test year)	$21,909	$21,909	$0
Dealer advertising coop - Home Fire (base year)	$0	$5,000	$5,000
Dealer advertising coop - Home Fire (test year)	$8,460	$8,460	$0
Dealer advertising coop - Lisac's (base year)	$0	$5,000	$5,000
Dealer advertising coop - Lisac's (test year)	$8,460	$8,460	$0
subtotal	**$41,014**	**$73,007**	**$31,993**
total	**$77,962**	**$115,507**	**$37,545**

Q. Does this conclude your Reply Testimony?

A. Yes.

NW Natural®

Rates & Regulatory Affairs
UG 527
NW Natural Alternative Rate Mechanism
Data Request Response

Request No.: UG 527 CUB DR 35

Please explain, and provide any supportive documentation, the discrepancy in disconnection data listed in Docket RO 16 Q4 report for November and December 2025 (139 disconnects in November and 213 in December), and the Company's response in CUB DR 32 stating:

> "From November 15 through December 31, 192 bill discount participants were disconnected for non-payment."

How were less households found to be incorrectly disconnected than what is listed in RO 16 reports? Especially if for all of December the moratorium was supposed to be in place, and there were 213 disconnects in that month alone?

Response:

This difference is the result of an unperceived nuance in the RO 16 data query used for the metric of the number of bill discount participant disconnections. Also, the 192 amount is a system number and includes Washington customers.

The metric of 192 customers disconnected provided in the Company's response to UG 527 CUB DR 32 was derived by querying how many customers were on the bill discount program **at the time of disconnection**.

The metric for RO 16 reporting was derived by querying how many Oregon customers who were disconnected for non-payment were also in the bill discount program that month, **but not necessarily at the time of the disconnection**. Because it is very common for customers to enroll in the bill discount program after they are disconnected – for example, when calling to get reconnected, the CSRs will ask if they would like to self-certify for the bill discount program – the query for the RO 16 report metric will be higher. This is because it will include disconnects for customers that were not in the bill discount program at the time the disconnection occurred.

In reconciling these query parameters, an additional nuance was identified in that the 192 impacted customers inadvertently included only those customers in the bill discount program whose bill discount participation did not change in the period between when the disconnection was scheduled and when the disconnection was completed. However, the number of impacted customers should have also included those

customers who had changes in their bill discount enrollment in the several days' time that may occur between the disconnection being scheduled and the disconnection being completed. For example, a customer may have had their enrollment period end during this interim period and re-enrolled accordingly. Taking into account this nuance in the data query, an additional 22 customers were impacted, for a total of 214 customers on a system basis, or 198 customers on an Oregon basis. Given this, the Company provides the following original and amended count of impacted customers:

Original count

	Nov	Dec	Total
OR	41	135	176
WA	4	12	16
Total	45	147	192

Corrected count

	Nov	Dec	Total
OR	47	151	198
WA	4	12	16
Total	51	163	214

Of the 22 additional impacted customers, all but one were reconnected (the majority were same day or next day). Any reconnection fees are being refunded and all of the impacted customers will receive the $150 bill credit. NW Natural left a voicemail with the one customer who has not reconnected to contact us to be reconnected at no charge.

Due to the updated count of impacted customers, NW Natural will provide supplemental responses to UG 527 CUB DRs 31, 34, 36, and 37 to add the details for the additional 22 impacted customers.

Both of the data query nuances discussed above will be addressed in future RO 16 reporting to more accurately reflect the number of customers disconnected for non-payment that were bill discount participants at the time of disconnection.

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UG 527/UG 528

OPENING TESTIMONY OF BOB JENKS
ON BEHALF OF THE OREGON CITIZENS' UTILITY BOARD

CUB 200

March 18, 2026

Mist Depreciation
Applying Retired Asset Policy to Mist GC 600 Retirement

Q. Please state your name, occupation, and business address

A. My name is Bob Jenks. I am the Executive Director of the Oregon Citizens' Utility Board (CUB). My business address is 610 SW Broadway, Ste. 400 Portland, Oregon 97205.

Q. Please describe your qualifications.

A. My witness statement is provided in Exhibit CUB/102.

Q. What is the purpose of this Joint Testimony?

A. In this opening testimony CUB discusses the Mist assets, update accumulated depreciation for Mist assets, and applying the Commission's retired asset policy (RAP) to the Mist GC 600 retirement.

Q. Are you sponsoring any exhibits?

A. Yes.

Exhibit 201	*In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision*, Docket No. UG 520, CUB Opening Testimony (April 2, 2025)
Exhibit 202	*In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision*, Docket No. UG 520, Joint Testimony in Support of First Partial Stipulation (July 10, 2025)
Exhibit 203	NWN Response to CUB DRs
Exhibit 204	CUB calculations based on NWN Response to CUB DR 16 att.
Exhibit 205	*In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision*, Docket No. UG 520, CUB Exhibit 103
Exhibit 206	*In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision*, Docket No. UG 520, NWN Exhibit 1402

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I. INTRODUCTION

Q. What is NWN asking for as it relates to Mist

A. NWN is requesting to replace the Mist GC600 Turbine Compressor. The Mist 600 replacement is related to the Mist GC500 Turbine Compressor Replacement Project addressed in UG 520.[1] As NWN testifies, "Like the GC500 unit, the GC600 unit, installed in 2001-2002 and having over 48,000 hours of operation, has exceeded its useful life expectancy."[2] Additionally, NWN is proposing Mist Main Power Feed Replacement Project and the Mist Well Separator Replacement Program. This program will replace the wells over five years. The first series of Mist Well Separators is scheduled to be replaced by October 2026, and this is the project for which the Company is seeking cost recovery in this proceeding.[3]

Q. What does CUB recommend as it relates to Mist?

A. As discussed below, CUB recommends $446,599 to account for accumulated depreciation of Mist assets. CUB also recommends applying the Commission's retired asset policy (RAP) to the Mist replacements consistent with the stipulated outcome of UG 520.

[1] NWN/200 Kizer-Karney-Pipes-Fellon/9.
[2] *Id.* at 11.
[3] *Id.* at 19-20.

II. MIST DEPRECIATION

Q. Please discuss how depreciation fits into an ARM?

A. As depreciation occurs, the remaining outstanding investment or ratebase is reduced, this in turn reduces the return that is applied to that ratebase, and it reduces taxes since the ROE component of rate of return represents net income which is taxed by the federal and state government and customers pay the taxes. Typically, between rate cases, there is regulatory lag on updating depreciation (accumulated depreciation), just as there is regulatory lag on adding new investment to rates. Since the regulatory lag in accumulated depreciation is in shareholders' interest, and the regulatory lag on new investment is in customers' interest, these lags can be viewed as offsetting.

When a utility files an ARM to add new capital investment in order to increase ratebase, it is imperative that it also update depreciation which reduces ratebase. Otherwise, customers will be paying rates that reflect an inflated ratebase. And charging customers for phantom ratebase violates Oregon's used and useful principle.[4]

While NWN claims that the ARM includes offsets to capital additions, including updating accumulated depreciation,[5] it was limited to IT&S capital investments for FERC accounts 303.1, 303.7, and 391.2.[6] NWN did not update accumulated depreciation for Mist assets even though the Company is adding additional, new investments to Mist.

[4] Pursuant to ORS 757.355, a utility may not include in rates the costs of plant "not presently used for providing utility service to the customer."
[5] *See* NWN/100 Kravitz-Walker/2.
[6] *See Id.* at 15.

Q. Is this adjustment within the scope of this proceeding?

A. Yes, the Commission has not established limits on the scope of ARM proceedings. The order in UE 435, however, provides supporting guidance for inclusion of this adjustment. There the Commission emphasized that it would only approve the use of the Seaside tracker ARM "if, and only if, it achieves an appropriate balance between customers and the company, correcting some of the negative consequences of single-issue ratemaking."[7] The Commission continued, noting it expected the Seaside ARM " to balance regulatory lag by truing up depreciation upon the inclusion of Seaside in rate base."[8] Under this guidance, including this adjustment within the scope is essential for use of the ARM to recover costs as it provides the opportunity that this proceeding will result in a balanced rate adjustment mechanism and just and reasonable rates.

That said, NWN did not include it in its proposal, but CUB does not believe that that limits our ability to raise this issue. Unlike UE 455 and UE 459, there is no MOU in this proceeding that defines the content of what parties can address in this proceeding. There is nothing that limits our testimony and evidence to the discrete items identified by NWN. If a utility is allowed to constrain the issues that CUB and other parties review, then it is using the ARM to make ratemaking more one-sided than it already is.

In addition, in its advice filing that started this docket, it described the purpose of the ARM as:

[7] Order No. 24-454 at 45.
[8] *Id.*; *See* also Order No. 25-417 at 4.

> The purpose of NW Natural's application for an alternative rate mechanism ("ARM") is to recover the costs of a limited subset of capital additions through a new base rate tariff, Schedule 123. Importantly, the ARM includes offsets to these capital additions, including retirements and **updating accumulated depreciation**, to ensure a balanced approach to ratemaking for the mechanism.[9]

Updating accumulated depreciation to offset the new capital additions is clearly within the purpose of the proceeding and should not be limited to the accounts that NWN proposed.

Q. What is NWN adding to Mist ratebase?

A. NWN is adding three new capital investments to the Mist Group. NWN uses group depreciation of assets at Mist and these new investments are being added to the Mist Group[10]. The three assets being added are:

Figure 1: Mist additions[11]

Mist Additions	**Amount Added to Ratebase (Oregon allocated)**
Mist GC600 Turbine Compressor Replacement	$11,100,000
Mist Main Power Feeder Replacement	$3,900,000
Mist Well Separator Replacement	$1,000,000
Total	$16,000,000

NWN's ratebase as of December 31, 2025, for Mist assets is $212,317,206.[12] This includes two months of depreciation after the rate effective date of their last GRC. CUB estimates that the ratebase that is currently in rates is $213,024,930.[13] Under NWN proposal, this new ratebase will be added to rate base established in 2025, rather than the

[9] *See* NWN Advice Filing 25-25, p 1 *(emphasis added)*.
[10] CUB/203 Jenks/1-2.
[11] *See* NWN/200 Kizer-Karney-Pipes-Fellon/ 18-22.
[12] CUB/203 Jenks/3-4.
[13] CUB/204 Jenks.

ratebase that will exist on the rate effective date of this case which CUB estimated will be $208,785,734.[14]

Q. What is the effect of accounting for accumulated depreciation?

A. The annual depreciation of Mist assets was approximately $4,239,196.11 in 2025.[15] If this is adjusted to account for another 12 months of depreciation, the depreciation expense is reduced to $4,154,836.11, which reduces revenue requirement by $84,360.[16] Updating the accumulated depreciation also reduces the Company's return on these assets. Because customers pay the income taxes that are applied to the company's net income (pre-tax ROE), the return must be adjusted for taxes. CUB estimated that the pre-tax return is $362,239.[17]

In sum, CUB recommends that NWN's revenue requirement be reduced by $362,239.31 plus $84,360 or $446,599 to account for accumulated depreciation.

Q. Is that the limit of CUB's adjustment for accumulated depreciation?

A. At this time that is what CUB is proposing. CUB is still reviewing whether other projects the Company describes as discreet projects or public work projects require updates to accumulated depreciation in order to avoid customers being charged for ratebase that is not used and useful.

[14] CUB/204 Jenks.
[15] *Id.*
[16] *Id.*
[17] *Id.*

III. RETIRED ASSET POLICY APPLIED TO MIST GC 600

Q. What is the retired asset policy?

A. As discussed in UG 520, the retired asset policy (RAP) is the culmination of the outcomes of the Trojan proceeding and subsequent Commission decisions interpreting Oregon's used and useful law.[18] Our UG 520 testimony has been included as CUB Exhibit 201 and goes into the background of the RAP.[19] In sum, the RAP recognizes that pursuant to ORS 757.355 Oregon only allows a utility to recover from customers the costs that are associated with assets that are used and useful in providing service to customers. After removing the undepreciated value from rate base, ORS 757.140 provides for the recovery of undepreciated utility investments, including retired plant, when the Commission determines that the retirement is due to ordinary wear and tear, casualties, acts of God, acts of governmental authority or the retirement is in the public interest.[20] In this instance the Commission has discretion to make the utility whole by permitting recovery of its original capital investment, along with an interest rate that represents the time value of money, but the utility is not allowed to earn a higher rate on equity.[21] The RAP derived from Order No 20-473 and the outcome appeals of the retired Trojan nuclear power plant's undepreciated costs.[22] Order No. 20-473 made clear that the use of this policy applies to retirements even when the utility uses group depreciation.[23]

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[18] CUB/201Jenks/13-18.
[19] *See id.* 14-22.
[20] *See* UE 374, *In the Matter of PACIFICORP, dba PACIFIC POWER, Request for a General Rate Revision* Order No. 20-473, 91-92 (Dec. 18, 2020).
[21] CUB/201 Jenks/14.
[22] UM 989, *This filing implements the settlements entered into by the Citizens Utility Board, OPUC Staff, and PGE to remove the Trojan Investment and other regulatory assets and liabilities from the Company's balance sheet*, Order No. 00-601 (Sept. 29, 2000).
[23] Order No. 20-473 at 83-84.

Q. How does UG 527 compare to UG 520 as it relates to these Mist compressor retirements?

A. The Mist GC 500 was installed in 1998, and Mist GC 600 was installed in 2001-02.[24] The Compressors are in FERC account 354.[25] In the depreciation study included with NWN UG 520 filing, the assets in FERC account 354 depreciate over 50 years.[26] In both cases, NWN's replacement of Mist Compressors involve retirement and replacement of assets. As NWN did in UG 520, NWN has again proposed to keep the undepreciated amounts of the retiring assets in rate base. As CUB explained in UG 520 and above, leaving unrecovered balance associated with the retired Mist assets in rate base is contrary to ORS 757.355, which prohibits a utility from earning a return on property that is not used and useful. In UG 520, CUB argued retirement and replacement of GC 500 is in the public interest, and therefore NWN is entitled to interest at the time value of money, but not a return on the investment.

Q. What should be removed from rate base to account for Mist GC 600 retirement?

A. GC 600 was installed in 2001-02[27] and NWN states it will be removed by October 2026. This reflects an actual useful life of 24 years, rather than the depreciable life of 50 years.[28] CUB looked at the PUC order from UG 132, which was the rate case following the beginning of the useful life of the GC 500. In that case, the Commission approved adding $27,322,000 in rate base to account for new investments at Mist.[29] Since Mist GC 600 will have depreciated for 24/50 years of its depreciable life, using this same figure for Mist GC

[24] CUB/201 Jenks/19 (citing UG 520 /NWN/100 Palfreyman-Kravitz/14).
[25] CUB/205 Jenks/1.
[26] CUB/206 Jenks.
[27] CUB/201 Jenks/19.
[28] NWN Initial Filing, *UG 527*; *NWN OPUC Advice No. 25-25*, at 1 (Nov. 25, 2025).
[29] UG 132, *In The Matter Of The Application Of Northwest Natural For A General Rate Revision*, Order No. 99-697, Appendix D, page 5 (Nov. 12, 1999).

600, CUB estimates its unrecovered Oregon capital investment upon retirement will be $14,207,440.

Q. What was the outcome of UG 520 as it relates to these Mist compressor retirements?

A. In our UG 520 opening testimony, under the RAP CUB recommended NWN remove the undepreciated balance of Mist GC 500 from its group depreciation account in rate base (FERC Account 354) and placed in a regulatory asset, where it would be amortized over 23 years at 4.499 percent, representing the time value of money.[30] In its reply testimony NWN estimated that the undepreciated portion of the GC 500 compressor upon its retirement would be approximately $11.1 million.[31]

The stipulation followed this same mechanism but with different figures. In the first partial stipulation, the Stipulating Parties agreed that NW Natural will remove $11.1 million, representing the net book value of the GC 500 Mist Compressor, from FERC Account 354, resulting in a reduction to revenue requirement of $1.378 million. The Stipulating Parties further agreed that the $11.1 million will be placed in a regulatory asset and recovered over a period of eight years through a separate base tariff schedule to be filed with the Company's compliance filing in UG 520. The Stipulating Parties agree to use a 4.499 percent interest rate for the regulatory asset. The amortization of the regulatory asset is $1.683 million per year through the separate rate schedule.[32] The Commission accepted this stipulation.[33]

[30] CUB/201 Jenks/20-21.
[31] CUB/202 Jenks/32.
[32] *Id.* at 32-33.
[33] *See* Order No. 25-420.

Q. What accounted for the difference between CUB's estimate in UG 520 of the unrecovered Oregon capital investment and that estimated by NWN?

A. In its UG 520 reply testimony, NWN stated CUB's calculation "overstates the undepreciated balance by not taking into account cost of removal and salvage value, and for the actual accumulated depreciation over the years as the depreciation rate has changed."[34] NWN then stated the undepreciated balance of components of GC 500 that are being replaced is $11.1 million as not all of the related assets are being replaced.[35] The parties agreed to use $11.1 million for the stipulation.[36] While CUB recommends removing $14,207,440 from rate base to represent the 26 years of estimated useful life remaining in rate base, CUB is open to supported adjustments from the Company to account for removal and salvage value, changed depreciation rate, etc.

Q. What does CUB recommend here?

A. Applying the RAP to the Mist GC 600 here, CUB recommends removing $14,207,440 from rate base. Subsequently, based on RAP and the terms of the stipulation in UG 520, CUB recommends $14,207,440 be placed in a regulatory asset and recovered over a period of eight years at 4.499 percent through a separate base tariff schedule to be filed with the Company's compliance filing in UG 527.

[34] UG 520/NWN/3000 Spanos-Wilson-Kravitz/20.
[35] *Id.*
[36] CUB/202 Jenks/32.

IV. CONCLUSION

Q. Please summarize your recommendations.

A. Through applying the Commission's Retired Asset Policy, CUB recommends removing the undepreciated $14,207,440 from rate base and placing it in a regulatory asset to be recovered over a period of eight years at 4.499 percent through a separate base tariff schedule to be filed with the Company's compliance filing in UG 527.

Note that this is a summary of our recommendation. The summary should not be read in isolation, but with our testimony as a whole.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UG 520

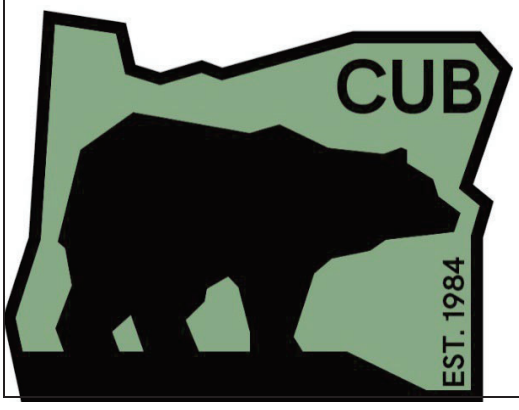
In the Matter of	)
	)
NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL,	)
	)
Request for a General Rate Revision.	)
	)
	)

OPENING TESTIMONY

OF THE

OREGON CITIZENS' UTILITY BOARD

April 2, 2025



UG 520/CUB/100
Jenks/1

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UG 520

In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision.	)	OPENING TESTIMONY OF THE OREGON CITIZENS' UTILITY BOARD

Q. Please state your name, occupation, and business address.

A. My name is Bob Jenks. I am the Executive Director of the Oregon Citizens' Utility Board (CUB). My business address is 610 SW Broadway, Ste. 400 Portland, Oregon 97205.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in exhibit CUB/101.

Q. What is the purpose of your testimony?

A. I respond to Northwest Natural's ("NWN's") Opening testimony and make recommendations regarding ROE, Capital Structure, the treatment of undepreciated investment in Mist Compressors, the treatment of undepreciated investment in IT&S, the treatment of stranded costs due to electrification, and CUB's concerns with OLGA given recent changes to LIHEAP. In addition, I discuss issues related to group depreciation, and depreciation studies generally.

A table of contents for my testimony is as follows:

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Q. Are you sponsoring exhibits in this proceeding?

A. Yes. I am sponsoring five exhibits. Exhibit 101 is my witness qualifications. Exhibit 102 contains data responses pertaining to group depreciation of the Mist Compressors. Exhibit 103 contains a data response pertaining to undepreciated investment. Exhibit 104 concerns LIHEAP. Exhibit 105 includes copies of the hyperlinked articles and websites included in this testimony.

I. INTRODUCTION

Q. What is Northwest Natural (NWN) requesting in this case?

A. NWN is requesting a rate increase on November 1, 2025, of 6.5% for single family homes and 6.7% for multi-family buildings[1]. NWN lists several factors as drivers of this rate increase:

- Mist Compressors[2]
- Modernizing IT&S Systems[3]
- Seismic Upgrades to Regional Resource Centers[4]
- Distribution System and Storage Investment[5]
- Meter Modernization[6]
- Depreciation Rates[7]

Q. Do you agree that these items are the drivers of the case?

A. Yes and no. While CUB agrees that these elements are included in the case and make up much of the $62,064,430 increase[8], we also recognize that NWN did not list its proposed increase in ROE and its proposed increase to the equity component of the capital structure as major drivers. NWN is proposing to increase its ROE from 9.4% to 10.4% and increase the equity component of its capital structure from 50% to 52%.[9] Both of these changes increase returns to NWN's shareholders. As

[1] UG 520 – NWN Executive Summary, Exhibit A, p 2.
[2] UG 520 – NWN Executive Summary, p. 4
[3] *Id.*
[4] *Id.* at 5.
[5] *Id.*at 6.
[6] *Id.* at 7.
[7] *Id.*
[8] UG 520 – NWN Executive Summary, Exhibit A.
[9] UG 520 – NWN Executive Summary, p. 3.

the chart below shows, this increase in shareholder return is more than $16 million. Because shareholder returns come out of net income which is taxed at a 27% combined federal and state tax rate[10], the cost to customers for this additional requested shareholder return is more than $20 million or 33.2% of the overall rate hike.

Figure 1 – Effect of Increase in Shareholder Return

	Current ROE and Capital Structure	Proposed ROE and Capital Structure
Rate Base[11]	2,293,722,494	2,293,722,494
Equity Component[12]	1,146,861,247	1,192,735,697
ROE[13]	107,804,957	124,044,512
Increase in ROE		16,239,555.26
tax rate (27%)[14]		4,384,679.92
total cost		20,624,235.18
% of overall increase		33.2%

The proposed increase in returns to shareholders accounts for more than 33% of the proposed increase in this case, so it must be considered a major driver of this case.

Q. How does this increase fit into the broader issue of affordability?

A. This increases effects affordability in multiple ways. The first is how this increase contributes to the increase that customers will receive on November 1, 2025. And the second is the cumulative increase that customers have had from a series of rate increases.

Q. How does this increase contribute to the November 1 increase?

[10] UG 520 – NWN, 1500/Walker/16.
[11] UG 520 – NWN, 1601/Wyman.
[12] UG 520 – NWN Executive Summary, p 3.
[13] *Id.*
[14] UG 520 – NWN, 1500/Walker/16.

A. NWN is proposing a rate increase of 6.5% to 6.7% for residential customers[15]. But this will not be the only rate adjustment that affects customers on November 1, 2025. NWN has designed this rate increase to go into effect at the same time as the PGA, which has two major components: 1) Projected gas costs for usage after November 1, 2025, and a true up for gas costs consumed between November 1, 2024, and November 1, 2025. In addition, NWN has filed a deferred account to track the cost of tariffs on Canadian natural gas.[16] Because the PGA true-up of actual gas costs includes a sharing mechanism, NWN deferral would remove the price increase on gas caused by US implemented tariffs from the PGA and allow recovery with no sharing.

The problem is that as CUB writes this testimony, we have no idea what the combined increase between this case, and the PGA and the tariff deferral will be on November 1. Should CUB be proposing a rate mitigation adjustment, just in case the combined increase reaches a level of rate shock?

Q. The second concern for affordability is the accumulation of rate increase that NWN has been putting on its customers. Please explain this concern.

A. Since 2020, this is NWN's 4th general rate increase. Customers saw general rate increases in 2020, 2022, 2024 and now 2025. In addition, customers have had to absorb increases in the commodity cost. Looking back at the 2020 rate case, NWN's testimony showed that without that increase residential customers would be

[15] UG 520 – NWN, Executive Summary, Exhibit A, p 2.
[16] *See* UM 2369, *In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Application for Authorization to Use Deferred Accounting for Tariffs on Imported Natural Gas from Canada* (Jan. 31, 2025).

expected to pay $391 million in revenue and use 398 million therms[17], for a rate of 98 cents per therm. After this case, NWN is projecting that residential customers will contribute $676 million in revenue and use 416 million therms for a rate of 1.62[18]. This represents a 65% increase, since before a rate increase went into effect in November 2020.

II. ROE AND CAPITAL STRUCTURE

A. ROE

Q. Does CUB support NWN's request for 10.4% ROE?

A. No. Such a figure is out-of-line with other regulated utilities in the state and is not supported by the Company's own ROE analysis. CUB is recommending a ROE of 9.24%. The Commission made clear in the recent PGE rate case that frequent rate cases protect utilities from regulatory lag, reduce utility risk, and should be reflected in a lower ROE.

Q. What is NWN's reasoning for requesting a higher ROE?

A. NWN cites two reasons. First, it claims that long term interest rates have increases "substantially" from the "historic lows of 2020[19]. Second, it claims that environmental policy in the Pacific Northwest had increased the "perceived" risk of investing in the Company[20].

[17] UG 388, *In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision*, NWN, Wyman/1101 and Wyman/1102.
[18] UG 520, NWN, Wyman/1601 and Wyman/1602.
[19] UG 520, NWN, 100/Palfreyman-Kravitz/28.
[20] *Id.*

Q. How do you respond to the argument that long term interest rates have increased from their historic lows?

A. It is true that in 2020, that the height of the COVID pandemic had an effect on economic conditions, including long-term interest rates and unemployment statistics. It was in April of 2020 that unemployment approached 15%[21]. CUB agrees that COVID had significant impact on the economy in 2020. But as the economy returned to more normal conditions, long-term interest rates have been fairly stable. The chart below shows 10 year treasury rates for the last 3 years.

Figure 2: Yield on 10-year Treasury Bonds[22]

Today yields on 10-year treasury bonds are at nearly the same level as they were in November 2024 when NWN last general rate case went into effect and are only slightly above the yields from November 2022 when NWN rates went into effect from the 2022 general rate case. NWN's current ROE was reasonable in 2022 and 2024.

[21] US Bureau of Labor Statistics, April 2020 unemployment rate was 14.8.
[22] Yield on 10-year Treasury Bonds, (March 25, 2025), https://ycharts.com/indicators/10_year_treasury_rate

Q. How do you respond to NWN's argument that environmental policy creates additional risk in the Pacific Northwest?

A. I disagree. NWN sells methane, a fossil fuel. As the world responds to climate change there is a need to reduce the combustion of fossil fuels. This is true in the Pacific Northwest and everywhere else in the world. There is no doubt that this creates a risk for companies whose main business is marketing fossil fuels. In the Pacific Northwest Oregon and Washington are advancing policies that attempt to address carbon emissions that are the cause of climate change. But these policies do not increase the risk of a gas utility like NWN, they reduce the investment risk of a gas utility like NWN. Let's look at two examples, line extension allowances and renewable natural gas.

Line Extension Allowances

In the 2022 rate case, the Commission approved a phase out of NWN's line extension allowance (LEA)[23]. This is a subsidy that the Company provides to home builders to connect new homes to the natural gas network. But the service pipe that is a major element of the LEA has a depreciable life of as long as 60 years[24]. Because of climate change and the need to reduce the use of fossil fuels, there is doubt whether many of the new homes that are being connected will still be purchasing the gas commodity decades from now. There is a clear investment risk associated with investing in service pipes that may not be used and useful for the entirety of their depreciable lives. Because in Oregon, utility investors are not

[23] UG 435, *In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision,* Order No. 22-388 (Oct. 24, 2022).
[24] UG 520, NWN, 1402/Spanos/ 53.

allowed to earn a return on undepreciated property that is no longer used and useful, LEAs place a risk on utility investors. Rather than increase investor risk, the phase out of the LEA reduced the investor risk.

Renewable Natural Gas

NWN touts renewable natural gas (RNG) as part of the solution to the climate change challenge of fossil fuels and has made several investments in RNG[25]. But renewable natural gas is significantly more expensive than fossil gas. Without policies that recognize the need to address climate change, NWN would be unable to justify bringing higher priced RNG into its resource mix. The environmental policies that NWN cites are lowering the risk of investing in RNG.

Climate change presents a huge challenge and investment risk to gas utilities. By addressing climate change through a series of government policies, Oregon is actually reducing the investment risk associated with a gas utility.

Q. Please explain how NWN's analysis fails to support a 10.4% ROE.

A. NWN has extensive testimony on ROE and proposes a variety of models to forecast the ROE that is necessary to attract capital, including DCF, CAPM and equity risk premium. While it is not unusual for utilities to look at a variety of models for estimating ROE, for more than 20 years Oregon's preference has been a multi-state DCF model. Oregon first began primarily relying on this model in 2001[26] and in December 2024, reiterated that it is the method the Oregon Commission has

[25] *See* CUB Exhibit 105, NW Natural, Fueling a renewable energy future, (April 2, 2025), https://www.nwnatural.com/about-us/environment/renewable-natural-gas.
[26] UE 115, *PGE's proposal to restructure and reprice its services in accordance with the provisions of SB 1149*, Order No. 01-777 (Aug. 31, 2001).

"primarily relied" upon[27]. NWN used a multi-stage DCF model and the results of that model do not support an increase to the Company's ROE.

Figure 3: Results of NWN Multi-Stage DCF model

	Gas Proxy Group	Combined Proxy Group
30-day average	8.51%	8.45%
90-day average	8.66%	8.62%
180-day average	8.85%	8.85%

Q. What does CUB recommend for NWN's ROE?

A. In its recent decision in UE 435, the Commission reduced PGE's ROE because of financial pressures on customers and a recognition that frequent rate cases reduce shareholder risk[28]. As discussed above, NWN has had 3 rate cases in the last 4 years, and after this rate case, their rates to customers will have increased by more than 60% since 2020. The same conditions that the PUC was concerned with in the PGE case exist here. PGE's ROE was reduced by 16 basis points from 9.5% to 9.34%[29]. CUB recommends a similar reduction of 16 basis points, from 9.4% to 9.24%.

[27] *See* UE 435, *In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Request for a General Rate Revision*, Order No. 24-454 at 11 (Dec. 20, 2024).
[28] *See* Id. at 12.
[29] *Id.*

B. Capital Structure

Q. What is Northwest Natural's proposal for capital structure and does CUB support it?

A. NWN proposes to increase the amount of equity in its capital structure, moving from a 50/50 capital structure to a capital structure of 52% equity and 48% debt[30].

Q. What is CUB response to this proposed increase in the equity component?

A. Oregon has historically relied on a hypothetical capital structure of 50% equity and 50% debt. The Commission recently reasserted the policies behind this historic position:

> Using a hypothetical capital structure for ratemaking-regardless of whether the actual proportion of equity to debt is lower than the 50/50 hypothetical or higher than the 50/50 hypothetical-provides a consistent regulatory signal that a balanced structure supports the long-term best interests of utility ratepayers[31].

In some previous cases CUB proposed that utilities should provide an analysis to demonstrate that the capital structure of the utility is the best mixture of cost and risk[32]. Equity is more expensive than debt, but equity has a lower risk than debt. During the aftermath of the Great Recession, when the Federal Reserve was holding interest rates low to stimulate the economy, CUB argued that it was time to move away from assuming a 50/50 capital structure. If the policies of the federal reserve kept borrowing costs artificially low, then it could make sense for utilities to take on a bit more risk to reduce borrowing costs. But CUB was unable to convince other

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[30] UG 520 – NWN Executive Summary, p 3.
[31] UE 435, *In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Request for a General Rate Revision*, Order No. 24-454 at 13.
[32] UE 294, *In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Request for a General Rate Revision*, CUB/100/Jenks-McGovern/20-26; *see also* UG 325, *In the Matter of AVISTA CORPORATION, dba AVISTA UTILITIES, Request for a General Rate Revision*, CUB/100/McGovern/28.

stakeholders and never achieved any traction on changing this historic practice. That combined with the Commission's very recent reiteration of its historic practice has led CUB to accept the historic practice of using a hypothetical 50/50 capital structure.

Q. Does this historic practice benefit customers?

A. During the Great Recession with interest rates held artificially low, CUB believed changing historic practices would provide a customer benefit and CUB and believed that utilities should provide analysis that they are using a capital structure that balances cost and risk. Today, interest rates are not being used to stimulate a recessionary economy and NWN is proposing to increase the equity component to reflect its forecasted equity component over the next 12-24 months[33]. In this case moving away from a 50/50 hypothetical structure would harm customers.

Q. What is CUB's recommendation for Capital Structure?

A. As noted above, in the most recent PGE rate case, the Commission stated its preference for a hypothetical 50/50 capital structures "regardless" of whether the actual capital structure varied from this amount[34]. NWN does not provide good reasons to depart from this Commission precedent. CUB recommends a capital structure of 50% equity and 50% debt.

Q. Please summarize your recommendations to the Commission.

A. CUB recommends a 9.24% ROE and a 50/50 Capital Structure.

[33] UG 520 – NWN, 400/Nelson/70.
[34] *See* UE 435, *In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Request for a General Rate Revision*, Order No. 24-454 at 13.

III. RETIRED ASSETS, MIST COMPRESSORS, AND STRANDED COSTS

A. Oregon's Approach to Retired Assets

Q. What are your concerns about retired assets, depreciable lives, group depreciation and stranded costs?

A. NWN's replacement of Mist Compressors involve retirement, and replacement of assets. Oregon has established policies around retirement of utility assets. CUB is concerned that NWN seems to believe that group depreciation allows for an exemption from these policies.

Q. What is Oregon's policy regarding retired assets?

A. Generally, Oregon only allows a utility to recover from customers costs that are associated with assets that are used and useful in providing service to customers. An exception to this used and useful approach is when the Commission finds that an asset is retired in the public interest. In this circumstance, the utility is made whole by being allowed to recover its original capital investment, along with an interest rate that represents the time value of money, but the utility is not allowed to earn a higher rate on equity.

CUB supports a policy of limiting recovery of retired property to instances where the Commission finds that retirement is in the public interest and disallows the application of the utility's return on equity to the undepreciated investment. This is a good policy that balances the interests of utilities and customers. Utilities only profit from investments that are productive and benefit customers, but utilities are

made whole and allowed to recover their initial investment in assets when that retirement provides a benefit. In effect, this policy shares the stranded cost risk of assets being removed before the end of their useful lives between customers and shareholders. It also helps temper the incentive that utilities have to make capital investments and to depreciate those investments over long periods of time.

Q. Please explain.

A. Utilities profits are driven by three inputs: capital investments, the depreciation period, and the return on equity. A utility finances a capital investment with a mixture of debt and equity, which combined make up the rate of return. Each year they charge customers their rate of return multiplied by the undepreciated investment. This creates an incentive to make capital investments, and it creates an incentive to depreciate capital investments over the longest period of time that can be justified because profits are increased by the size of the undepreciated investment. For example, a $100 million investment in software might have a 10-year useful life, but if a utility had the option of depreciating it over a 10-year or a 20-year life, a 20-year life would increase the earned return on equity from the investment from $27 million to $51 million.

Figure 4: Depreciable Lives and ROE example

Year	10 year (ave. ratebase)	ROE	20 year (ave. ratebase)	ROE
1	95	5.1376	95	5.1376
2	85	4.5968	90	4.8672
3	75	4.056	85	4.5968
4	65	3.5152	80	4.3264
5	55	2.9744	75	4.056
6	45	2.4336	70	3.7856
7	35	1.8928	65	3.5152
8	25	1.352	60	3.2448
9	15	0.8112	55	2.9744
10	5	0.2704	50	2.704
11			45	2.4336
12			40	2.1632
13			35	1.8928
14			30	1.6224
15			25	1.352
16			20	1.0816
17			15	0.8112
18			10	0.5408
19			5	0.2704
	Total	27.04		51.376

Q. How does the risk of stranded costs impact depreciation incentives?

A. Offering some counter to these depreciation incentives is the risk of stranded costs. As I explained above, the Company loses the opportunity to earn a return on equity when an investment is retired and it has to make the case that the retirement was in the public interest. This creates an incentive for a utility to ensure that the depreciable lives of assets are realistic. And it reinforces the matching principle where regulation wants to match the benefits of an investment with the costs.

Q. How does group depreciation affect this?

A. Group depreciation should not affect this. Investments are either used and useful or not used and useful. And the policies that apply to retired investments apply when an investment is no longer used and useful regardless of group depreciation. NWN,

however, argues that group depreciation means the Company no longer has to be concerned about undepreciated investment in retired assets[35]. In CUB Exhibit 102, Staff asks NWN whether the Mist Compressors that are being retired are fully depreciated. NWN responds that the compressors are depreciated at the group level rather than at the individual asset level and that because depreciation is done at the group level, rather than the individual level, any undepreciated amounts will stay in the group account[36]. According to the Company "some assets are retired before expectation and others after expectation"[37]. In other words, ratepayers could be paying for annual depreciation and a rate of return on the undepreciated amounts of retired assets that are no longer used and useful because these stray amounts remain lumped in the group depreciation bucket.

Q. Has the Commission ruled on how group depreciation affects retired property?

A. Yes. In docket UE 374, the Commission addressed this exact issue as it related to PacifiCorp's replacement of traditional meters with AMI meters. PacifiCorp, like NWN, argued that because the company uses group depreciation the company did not have to worry about undepreciated investment in individual meters when they were replaced. The Commission flatly rejected that argument[38]:

> Pursuant to ORS 757.355, a utility may not include in rates the costs of plant "not presently used for providing utility service to the customer." The meters replaced during the company's AMI roll out, completed this year, are no longer in service to customers. Although PacifiCorp argues that removal of the replaced meters is contrary to the company's use of group

[35] *See* CUB Exhibit 102.
[36] *Id.*
[37] *Id.*
[38] *See* UE 374, *In the Matter of PACIFICORP, dba PACIFIC POWER, Request for a General Rate Revision* Order No. 20-473, 88-92 (Dec. 18, 2020).

> depreciation, the scale of replacements, 85 percent of the company's meters, is distinguishable from the gradual replacement and retirements of individual units over time. Additionally, because the company now seeks to include all of the new AMI meters in rate base, it is appropriate to remove the replaced meters in determining rate base in this proceeding….
>
> We agree with Staff that the company should have sought to accelerate depreciation for these meters ahead of their retirement if it hoped to earn its rate of return on this plant balance. ORS 757.140 provides for the recovery of undepreciated utility investments, including retired plant, when the Commission determines that the retirement is in the public interest. The company demonstrated benefits of replacing its existing meters with AMI, including those incorporated into rates in this case. We find that the retirement of the existing meters as part of the AMI installation to be in the public interest. Accordingly, we adopt AWEC's proposal to remove the undepreciated balance of the company's old meters from rate base, to be recovered through a regulatory asset. We find no additional adjustment is required to adjust depreciation expense. AWEC provided a calculation of the net book value of retired meters to be removed from rate base of $16,126,628. Staff agrees with AWEC's calculation. We adopt AWEC's proposal to establish a regulatory asset and find AWEC's calculated estimate of the net book value of $16,126,628 should be amortized over 10 years. Because we determined that early retirement of the meters is in the public interest, PacifiCorp is entitled to interest at the time value of money, but not a return on the investment.[39]

Q. Is CUB proposing a new policy?

A. No. The policy that came out of Order No 20-473 is the Retired Asset Policy that was applied to the retired Trojan nuclear power plant[40]. Order No 20-473 made clear that the use of this policy applies to significant retirements even when the utility uses group depreciation.[41]

[39] *Id.* at 91-92.
[40] UM 989, *This filing implements the settlements entered into by the Citizens Utility Board, OPUC Staff, and PGE to remove the Trojan Investment and other regulatory assets and liabilities from the Company's balance sheet*, Order No. 00-601 (Sept. 29, 2000).
[41] *See* UE 374, *In the Matter of PACIFICORP, dba PACIFIC POWER, Request for a General Rate Revision* Order No. 20-473 (Dec. 18, 2020).

B. Applying the Retired Asset Policy to Mist Compressors

Q. Is there undepreciated investment in the Mist Compressors?

A. CUB believes the answer is yes. The two Mist Compressors were installed in 1998 and 2001-02[42]. The Compressors are in FERC account 354[43]. In the depreciation study included with NWN filing, the assets in FERC account 354 depreciate over 50 years[44]. This is consistent with the previous depreciation study[45]. NWN would not answer a data request from the Staff on whether the individual compressors were fully depreciated, citing group depreciation[46]. The FERC account associated with the group depreciation has a net plant balance of $21,070,537 on an Oregon allocated basis.

This case is focused on replacing the GC 500, which was installed in 1998[47] and will be removed by October 2025[48]. This reflects an actual useful life of 27 years, rather than the depreciable life of 50 years. CUB looked at the PUC order from UG 132, which was the rate case following the beginning of the useful life of the GC 500. In that case, the Commission approved adding $27,322,000 in rate base to account for new investments at Mist[49]. This is the best estimate CUB has as to the initial capital investment. Since it has depreciated for 27/50ths of its depreciable

[42] UG 520 – NWN, 100/Palfreyman-Kravitz/14.
[43] CUB Exhibit 103.
[44] UG 520 – NWN, 1402/Spanos/52.
[45] UM 2312, *In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Updated Depreciation Study*, NWN, Depreciation Study, page VI-5.
[46] CUB Exhibit 102.
[47] UG 520 – NWN, 500/Kizer-Johnson/31.
[48] UG 520 – NWN, 500/Kizer-Johnson/45.
[49] UG 132, *In The Matter Of The Application Of Northwest Natural For A General Rate Revision*, Order No. 99-697, Appendix D, page 5 (Nov. 12, 1999).

life, CUB estimates its unrecovered Oregon capital investment upon retirement will be $14,753,880.

Q. Is CUB opposing recovery of this $14.8 million?

A. No. CUB believes that NWN makes a reasonable case that this compressor needs to be replaced[50]. While NWN did not include a request to find that the current Mist Compressor is being retired in the public interest, CUB makes that request here. Per the Retire Asset Policy, this request allows the Company to recover its capital investment but not earn its return on the plant.

Q. Why is CUB recommending the Mist Compressor be retired in the public interest?

A. Mist is an underground storage facility for natural gas and NWN uses it to meet winter demand on its system. This allows the Company to avoid the expense of purchasing additional firm capacity on interstate pipelines. CUB believes that NWN makes a reasonable case that the compressor needs to be replaced to support operations at Mist. CUB is not opposing retiring and replacing the compressor.

Q. How is CUB recommending this amount be recovered?

A. In the same manner as the PacifiCorp metering investment discussed above. NWN should remove $14.8 million from FERC account 354 and recover it through a regulatory asset. The PacifiCorp regulatory asset was amortized over 10 years. The remaining depreciable life of this assets is 23 years. While CUB is recommending sticking with the 23-year amortization period, we recognize that the Commission may want to shorten that period.

[50] UG 520 – NWN, 500/ Kizer-Johnson/30-45 and NWN, 505/Kizer-Johnson.

In the PacifiCorp case, UG 132, to determine an interest rate that reflected the time value of money, the Commission used a blended rate, composed of the "company's currently authorized cost of debt and Treasury bond yields.[51]" In this case, NWN is proposing 4.687% for the weighted average cost of debt[52]. The yield on a 10-year Treasury bond is 4.31%[53]. Therefore, the blended rate (50% of each) is 4.499.

This is not a huge adjustment. NWN is proposing a return on equity of 10.4%, a equity component of 52% and a cost of debt of 4.687%[54]. Applying this ROE and capital structure, along with a combined federal/state tax rate of 27%[55], creates a pretax return of $1.35 million. Creating a regulatory asset and using a blended rate of 50% debt and 50% 10-year treasuries, would reduce the overall return to $752,000 for an overall revenue requirement reduction of $598,000. But this adjustments importance is greater than its test year value. NWN claims this retirement is due to the compressors being at the end of their *useful* lives, but they are only about halfway through their *depreciable* lives. As a reminder, a utility can earn more on an asset the longer the utility stretches the depreciation life of that asset. The Company could have earned its full rate of return on the asset if it had accelerated depreciation, i.e., if it had shortened the depreciation life, before the plant was retired. Instead, because the Company used a depreciation life longer than the useful life of the compressor, the Company is left with $14.8 million in

[51] *In the Matter of PACIFICORP, dba PACIFIC POWER, Request for a General Rate Revision* Order No. 20-473 at 91-92 (Dec. 18, 2020).
[52] UG 520 – NWN, 1508/Walker/1.
[53] U.S. 10 Year Treasury Note, (March 25, 2025), https://www.marketwatch.com/investing/bond/tmubmusd10y?countrycode=bx.
[54] UG 520 – NWN, 1508/Walker/1.
[55] UG 520 – NWN, 1500/Walker/19.

undepreciated investment, which, under the Retired Asset Policy should no longer have a return on equity. By removing the earning opportunity from unproductive retired assets, the Commission is creating an incentive for the company to match useful lives with depreciation and minimize stranded costs.

CUB is recommending:

1. That the retirement of the Mist Compressor in October 2025 be found to be in the public interest.

2. That NWN remove $14.8 million from FERC account 354 and place it in a regulatory asset; and

3. That the regulatory asset should be amortized over 23 years with an interest rate of 4.499%, representing the time value of money.

C. Applying this Policy to the IT&S system

Q. What is NWN proposing with respect to its IT&S system?

A. NWN proposes to recover investments to replace end-of-life information technology and services ("IT&S") system.[56] This includes replacing "decades old" SCADA systems with new equipment and cloud-based services.[57] As we have seen with the Mist Compressors, just because the Company describes the old systems as at their end-of-life, this does not mean that they are at the end of the depreciable life.

[56] NWN Executive Summary, page 4.
[57] *Id.* at 4-5.

CUB recommends similar treatment for these assets:

1. That the retirement of the IT&S system be found to be in the public interest.

2. That NWN remove any undepreciated investments associated with the retired IT&S system from its rate base accounts and place them in a regulatory asset; and

3. That the regulatory asset should be amortized over 23 years with a interest rate of 4.499%, representing the time value of money.

D. Applying this Policy to Stranded Costs from Electrification

Q. Explain the issue with applying this policy to stranded costs from electrification?

A. The role of electrification in decarbonizing our economy has been discussed in recent rate cases, IRPs, and the Gas Fact Finding investigation. Anecdotal evidence (i.e., I know people who have electrified their home and discontinued gas service) suggests electrification is happening, though at a level that is less than new customer growth. But as customers electrify, what happens to the assets that are left behind? This becomes significant if electrification accelerates.

The service pipe, for example, serves a single customer. If that customer discontinues gas service then the service pipe is no longer used and useful. It becomes a retired asset. In this case NWN is proposing to reduce the depreciable lives of service pipes from 65 to 60 years. This means that new service pipes will have amortization that lasts until 2085. In light of climate change and Oregon

public policies to address climate change, it is unlikely that a broad fossil fuel gas system will be delivering methane to hundreds of thousands of households in 2085. While the current policy of phasing down the line extension allowance policy (LEA) reduces the potential for stranded costs for new service lines, there is a legacy of decades of service pipes in the ground now with decades of depreciation left.

Q. What is your recommendation with regards to applying the Retired Asset Policy to household electrification?

A. Under NWN's application of group deprecation, as households electrify and leave the system, the unamortized investment will remain in the group depreciation account and be financed at the utility's rate of return by the customers who are left. At its extreme, this means the last customer on the system will be responsible for paying all of the rate base for all of the pipes that are no longer used and useful but are part of the group depreciation account.

Of course, if electrification does cause the gas system to shrink, it may be that the service pipes are not the only assets that become no longer used and useful. It is important for the Commission to reassert Oregon's policy on retired plant. Currently, NWN has little incentive to limit new investment in long-term assets and little incentive to match the depreciable lives with the actual expected useful lives.

While the Commission has directed the Company to consider non-pipe alternatives[58], the Company has little incentive to invest in non-pipe alternatives. Applying Oregon's retired plant policy to NWN will help align the Company incentives with its customers' interests – a system filled with stranded costs will be harmful to both – and non-pipe alternative will reduce risk for both shareholders and customers.

Applying this policy requires that when customers leave the system and their service pipe (or other capital assets) are no longer useful, that the remaining undepreciated capital investment directly associated with that customer, and only that customer, be moved into a regulatory account, so it can be recovered at the time value of money. This requires tracking the beginning of service for each customer address, so the undepreciated investment can be calculated.

Reducing carbon is the public policy adopted by Oregon and reflected in HB 2021, and the CPP and likely future additional policies. Because electrification of households will reduce carbon emissions, CUB recommends that the Commission find that electrification is in the public interest and direct NWN to place plant that is retired due to electrification in a regulatory asset where it will earn interest at the rate of 4.496 %.

[58] LC 79, *In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, 2022 Integrated Resource Plan*, Order No 23-281 (Aug. 2, 2023).

IV.DEPRECIATION

A. Moving Away From Group Depreciation

Q. How does NWN depreciate its assets?

A. As discussed above, the Company uses the "Group Depreciation Method" for most assets, even large assets like the Mist Compressors.[59] Under the Group Depreciation Method, the service life and net salvage characteristics are estimated for each depreciable group.[60] The total cost of the group is spread out over the useful life of the entire group.[61] When the Company conducts a depreciation study, it reassess the useful life and salvage value of the assets in each group, including retirements, and adjustments to depreciation rates.[62]

Q. What is CUB proposing?

A. CUB is concerned about continuing to use group depreciation does not allow for the kind of insight now necessary into the lives of individual assets. Knowing the specific undepreciated investment in the Mist Compressors would have facilitated applying the retired asset policy. Instead of group depreciation, CUB would like to see the Company use unbundled individualized asset depreciation for assets that have significant cost, or assets that have long depreciable lives. This would allow stakeholders to scrutinize stranded costs.

[59] UG 490, *In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision*, Staff/1000 Dyck/10 (citing Staff/1002, NWN Response to DR 415).
[60] UG 520 – NWN, 1400/Spanos/5.
[61] UG 490, *In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision*, Staff/1000 Dyck/10 (citing Staff/1002, NWN Response to DR 415).
[62] *Id.*

In undertaking its depreciation studies, the Commission has tasked NWN with addressing "accelerated depreciation or other adjustments to asset depreciation schedules as a possible tool to mitigate uncertainty about decarbonization pathways and manage potential future risks to customers."[63] Likewise, even without a pathway, NWN's gas customers are electrifying. The value left on the system as customers chose to fuel switch and as Oregon's regulators adopt decarbonization pathways will leave behind stranded assets, that is, assets that are no longer used ahead of their useful life. Whichever pathway we follow, there is the potential for serious financial implications for the Company's captive ratepayers. By using group depreciation, we are limited in our ability to assess and mitigate against this financial impact. That is, group depreciation does now allow us to scrutinize which assets may be no longer used but are otherwise impacting their group's service life and net salvage characteristics.

Q. How does this accounting impact the depreciation of assets in rates?

A. Group depreciation is a simpler accounting method, but assets depreciate regardless of whether they are in group depreciation or depreciate individually. The difference is not in the depreciation of assets but in how we track that depreciation. Group depreciation came about in the days when utility accounting was done by hand on paper. Today, we have computers, software, digital tools and the ability to be more sophisticated in our tracking of asset depreciation.

Q. Has the Commission ever requested that NWN adjust its depreciation method to account for the uncertainty of decarbonization?

[63] UM 2214, *In the Matter of Northwest Natural Gas Company, dba NW Natural, Updated Depreciation Study*, Order No. 22-322 at 3 (Sep 7, 2022).

A. Yes, in in Order No. 22-322 on NWN's depreciation study filed at the end of 2021, the Commission explained that parties may seek to evaluate accelerated deprecation or other adjustments to asset depreciation schedules as a "tool to mitigate uncertainty about decarbonization pathways and manage potential future risks to customers." The Commission then directed NWN to include testimony in its subsequent depreciation study addressing accelerated depreciation.[64] NWN filed a new depreciation study in January 2024 in docket no. UM 2312, but NWN did not file testimony addressing accelerated depreciation.[65] Instead, NWN argued filing the new depreciation study in January 2024 rather than 2027 was responsive to the Commission's directive.[66] According to NWN, the depreciation study reflected the actual operations and depreciable lives of the assets on its system to enable the company to "begin [] discuss[ing] the justifications for, and impacts of, accelerated depreciation."[67] In testimony, NWN did not propose accelerated depreciation "due to the near term rate pressure of increasing depreciation expense in this filing to reflect the useful lives of its assets but is open to a discussion in a future proceeding."[68] The Company added that it was "not attempting to foreclose that discussion in a future filing appropriate for considering whether a disciplined approach to gradually increase depreciation expense to mitigate potential future uncertainties—while balancing intergenerational equity between today's customers and tomorrow's customers—is a reasonable approach for NW Natural and its

[64] *Id.*
[65] *See* UM 2312, *In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Updated Depreciation Study*, Order No. 24-302 at 3 ("NW Natural states that to be responsive to the Commission's directive, the company filed this depreciation study now, rather than wait until 2027.").
[66] *Id.*
[67] *Id.*
[68] *Id.*

customers."[69] In the UM 2312 order adopting the stipulation on the revised depreciation rates, the Commission reiterated its directive that the Company to include testimony addressing how the Company could use deprecation as a tool to mitigate customer risk in its next deprecation study.[70] Nonetheless, in the latest study, UM 2363, NWN has again declined to discuss depreciation of the gas system in the context of decarbonization of the gas system. Instead, NWN again filed a new depreciation study. In shortening the lives of certain assets in this latest study, NWN states that "it is very important to have our depreciation rates reflect the actual operations and depreciable lives of the assets on our system."[71] It's important to note that the Commission did not direct NWN to file these back-to-back depreciation studies. Nor does the law require back-to-back studies nor did the prior stipulations. The Commission directed testimony on accelerated depreciation, and in lieu of that, the Company undertook a new study.

Q. What happened in UM 2312, NWN's last depreciation study?

A. In January 2024, NWN filed a new depreciation study with the Commission, docketed as UM 2312. NWN used these depreciation rates proposed in depreciation study in UG 490. AWEC performed a detailed review of the depreciation study in that docket, noting that changes to the depreciation rates were key drivers of the rate

[69] UM 2312, *In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Updated Depreciation Study*, NW Natural's Updated Depreciation Study, cover letter at 2 (Jan. 2, 2024).
[70] UM 2312, *In the Matter of Northwest Natural Gas Company, dba NW Natural, Updated Depreciation Study*, Order No. 22-322 at 3 (Sep 7, 2022).
[71] UM 2363, *In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Updated Depreciation Study*, cover letter at 2 (Dec. 30, 2024).

increases in UG 490.[72] In August, the Commission adopted the stipulation entered into by NWN, Staff, AWEC in UM 2312. In doing so, NWN agreed to use the revised depreciation rates, as presented in the stipulation, as the basis for its depreciation rates in UG 490 effective November 1, 2024.[73] The stipulation provided that the revised depreciation parameters set forth in the stipulation would be used until the effective date of the company's next depreciation study.[74] Then, in December of 2024, NWN filed a new depreciation study.

Q. What has NWN proposed in the latest depreciation study?

A. Rather than discuss the concerns raised by the Commission related to stranded costs and mitigating risk, the Company seems to be doing nearly-annual depreciation studies and slowly reducing the depreciable lives of assets. Effectively, the company is accelerating depreciation to reduce the risk of stranded costs, but without admitting that this is what it is doing, and without any discussion of those risks, and what depreciable lives make sense in the context of climate change and electrification. For example, this new study reduces the depreciable lives of service pipes from 65 to 60 year[75]. This reduces the stranded cost risk of electrification, but only slightly. A better approach would be testimony that discusses the risks associated with electrification, how that affects the useful life of assets, and in the context of electrification what should be established as the useful life. Because of

[72] UM 2312, *In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Updated Depreciation Study*, Order No. 24-302 at 2 (Aug. 29, 2024).
[73] *Id.*
[74] *Id.*
[75] *See* UG 520 – NWN, 1402 Spanos/53; UM 2312, *In the Matter of Northwest Natural Gas Company, dba NW Natural, Updated Depreciation Study,* NWN, Depreciation Study at VI-7.

the rate impact of shortening useful lives, phasing in new useful lives could be used to mitigate ratepayer impact.

NWN's approach of having nearly annual depreciation studies may be a method to phasing in shorter depreciable lives but doing it in this manner removes context and disconnects the rate increases associated with accelerating depreciation from the benefit of such depreciation – reduced risk of stranded costs.

Q. What is the cost of these depreciation studies?

A. In UG 490, the proposed cost to customers from updating depreciation rates based on the study was $35,403 million, or 22.85% of the proposed Oregon revenue requirement, surpassing capital projects, which were 21.27% of the proposed Oregon RR.[76] There is no doubt that reducing depreciable lives increases the rates to customers. But it is unclear how these costs fit into a strategy of reducing the risk associated with electrification and climate change.

Q. Should customers continue to see nearly annual rate hikes associated with new depreciation studies?

A. No. Asking customers to bear higher costs, without explaining how these increased costs provide benefits, should be rejected.

[76] *See* UG 490, *In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision*, Staff/100 Muldoon/11 (chart shows the Rate Case Cost Drivers of UG 490).

V. LIHEAP AND OLGA

Q. What is LIHEAP?

A. LIHEAP is the Low-Income Home Energy Assistance Program. It is funded by the federal government and "provides critical short-term aid" to low-income households[77] for the cost of heating or cooling their homes. In FY 2022, Oregon received $34 million in LIHEAP funding[78]. It is a critical piece of this country's social safety net. In Oregon it is administered through county Community Action Programs, such as the Community Action Team that serves Columbia, Clatsop and Tillamook Counties[79]. From CUB's experience, LIHEAP plays a vital role in providing emergency relief to customers who cannot afford their bills and helps prevent disconnection of vulnerable families.

Q. What is OLGA?

A. OLGA is the Oregon Low-Income Gas Assistance program[80]. It is funded by NWN customers through a surcharge to the bills of residential customers[81]. Like LIHEAP, it is administered through local Community Action Programs[82].

Q. What is your concern with LIHEAP and OLGA?

A. OLGA was created to supplement LIHEAP.[83] LIHEAP and OLGA work together to help prevent shut offs by providing crisis support to low income households facing unaffordable bills. The two programs have the same income qualifications

[77] *See* CUB Exhibit 104.
[78] *Id.*
[79] CUB Exhibit 105, *Utility Assistance*, Community Action Team (April 2, 2025), https://cat-team.org/cat/utility-assistance.
[80] RO 10, *Qualified Project Reports per OAR 860-200-0200*, NWN, Oregon Low-Income Gas Assistance Program (OLGA) Annual Report for the 2023-2024 Program Year
[81] *Id.*
[82] *Id.*
[83] *Id.*

and are generally administered by the same agencies[84]. CUB is concerned that the current federal administration and Congress may reduce or eliminate LIHEAP funding before next winter. This concern was further validated on April 1, 2025, when the entire LIHEAP federal staff were terminated, despite there being a remaining $387 million in funds that had yet to be allocated for the year[85]. Mark Wolfe, the executive director of the National Energy Assistance Directors Association, noted that this action would likely grind LIHEAP programing to a halt[86]. If this or worse comes to be, the current level of OLGA funding will likely be insufficient to meet the emergency heating needs of low-income NWN households. There may be a need to increase OLGA funding. But this creates a ratecase timing issue. While the extent of the problem will likely be known when the Commission makes an October decision in this case, it is not known today and may not be known when rebuttal testimony is written.

Q. Does CUB have a recommendation regarding LIHEAP and OLGA?

A. At this time, we do not. CUB is talking to other stakeholders and may have a contingency proposal to make in rebuttal testimony.

[84] CUB Exhibit 105, Energy Assistance, Yamhill Community Action Partnership (YCAP), https://yamhillcap.org/energy

[85] CUB Exhibit 105, Nick Valencia et al., 'It's a bloodbath': Massive wave of job cuts underway at US health agencies, CNN Health (April 1, 2025, updated April 2, 2025, 11:06 AM EDT), https://www.cnn.com/2025/04/01/health/staff-cuts-at-federal-health-agencies-have-begun/index.html

[86] *Id.*

VI. CONCLUSION

Q. Please summarize your recommendations to the Commission.

A. Below is a numbered list here of recommendations made in testimony for easy reference:

1. ROE and Capital Structure:
9.24% ROE and a 50/50 Capital Structure.

2. Mist Compressor:
That the retirement of the Mist Compressor in October 2025 be found to be in the public interest.

That NWN remove $14.8 million from FERC account 354 and place it in a regulatory asset; and

That the regulatory asset should be amortized over 23 years with an interest rate of 4.499%, representing the time value of money.

3. IT&S System
That the retirement of the IT&S system be found to be in the public interest.

That NWN remove any undepreciated investments associated with the retired IT&S system from its rate base accounts and place them in a regulatory asset; and

That the regulatory asset should be amortized over 23 years with a***n*** interest rate of 4.499%, representing the time value of money.

4. Electrification

That the Commission find that electrification is in the public interest and direct NWN to place plant that is retired due to electrification in a regulatory asset where it will earn interest at the rate of 4.496 %.

Q. Does this conclude your testimony?

A. Yes.

UG 520/CUB/101
Jenks/1

WITNESS QUALIFICATION STATEMENT

NAME: Bob Jenks

EMPLOYER: Oregon Citizens' Utility Board of Oregon

TITLE: Executive Director

ADDRESS: 610 SW Broadway, Suite 400
Portland, OR 97205

EDUCATION: Bachelor of Science, Economics
Willamette University, Salem, OR

EXPERIENCE: Provided testimony or comments in a variety of OPUC dockets, including UE 88, UE 92, UM 903, UM 918, UE 102, UP 168, UT 125, UT 141, UE 115, UE 116, UE 137, UE 139, UE 161, UE 165, UE 167, UE 170, UE 172, UE 173, UE 207, UE 208, UE 210, UE 233, UE 246, UE 283, UG 152, UM 995, UM 1050, UM 1071, UM 1147, UM 1121, UM 1206, UM 1209, UM 1355, UM 1635, UM 1633, and UM 1654. Participated in the development of a variety of Least Cost Plans and PUC Settlement Conferences. Provided testimony to Oregon Legislative Committees on consumer issues relating to energy and telecommunications. Lobbied the Oregon Congressional delegation on behalf of CUB and the National Association of State Utility Consumer Advocates.

Between 1982 and 1991, worked for the Oregon State Public Interest Research Group, the Massachusetts Public Interest Research Group, and the Fund for Public Interest Research on a variety of public policy issues.

MEMBERSHIP: National Association of State Utility Consumer Advocates
Board of Directors, OSPIRG Citizen Lobby
Telecommunications Policy Committee, Consumer Federation of America
Electricity Policy Committee, Consumer Federation of America
Board of Directors (Public Interest Representative), NEEA

UG 520/CUB/102
Jenks/1

NW Natural®

Rates & Regulatory Affairs

UG 520

NW Natural Request for a General Rate Revision

Data Request Response

Request No.: UG 520 OPUC DR 403

By October 2025, will the compressors be fully depreciated?

Response:

The premise of the question does not reflect how assets are depreciated. Utilities follow group depreciation for all assets which is presented in the Company's 2023 Depreciation Study and has been followed for many years. Compressor Equipment are listed in FERC Accounts 354, 368 or 377. The Mist compressors are recorded in Account 354. Group depreciation provides for proper recording of assets into similar or like assets in order to establish proper recovery of all assets consistent with their life characteristics. Therefore, all assets in an account or group are depreciated at the group level rather than at the individual asset level. Additionally, the accumulated depreciation is recorded and maintained at that group or account level. Given the accumulated depreciation is maintained at the group or account level, when the compressors are retired, the amount of the retired plant as well as any associated net salvage will be credited to accumulated depreciation impacting the group or account rather than any individual asset recorded within the account. Consequently, some assets are retired before expectation and others after expectation. The remaining life technique ensures all assets within an account are fully depreciated no more, no less.

UG 520/CUB/102
Jenks/2

NW Natural®

Rates & Regulatory Affairs
UG 520
NW Natural Request for a General Rate Revision
Data Request Response

Request No.: UG 520 OPUC DR 404

If not, how will the remaining book value of the old compressors be accounted for?

Response:

Please refer the response provided to UG 520 OPUC DR 403 related to the explanation of group depreciation. As stated in the referenced response, once the compressor(s) are retired from service, the original cost of the asset is credited to plant-in-service for the account and also accumulated depreciation along with any net salvage value associated with the retirement of the asset. Given the full value of the asset has been credited to both plant-in-service and accumulated depreciation, the remaining service value (original cost and net salvage) of the account is recovered over the remaining life of the remaining assets within the account or group. The annual depreciation expense and rate are calculated considering the ratio of the accumulated depreciation (book reserve) to plant in order to ensure all investment is fully depreciated within the account.

UG 520/CUB/103
Jenks/1

NW Natural®

Rates & Regulatory Affairs
UG 520
NW Natural Request for a General Rate Revision
Data Request Response

Request No.: UG 520 OPUC DR 402

What will be the net plant balance at the end of 2024?

Response:

We are assuming this is asking for the net plant balance for FERC account 354 where the asset costs of the Mist gas compressors are held. The net plant balance of FERC account 354 at the end of 2024 is $23,685,406, or $21,070,537 on an Oregon allocated basis.

A LIGHT FOR THOSE IN NEED:
LIHEAP Enters a Fifth Decade of Service

May 2022

SERVING NEIGHBORS IN NEED

On Saturday mornings, Cincinnati resident Kim Navaro prepares herself for her next shift as a volunteer for St. Vincent de Paul. In the Greater Cincinnati region, St. Vincent de Paul is one of several organizations that help families in need connect with assistance programs, including rent, food, and utilities.

Navaro, who has been a volunteer since November 2020, has to ready herself for the Saturday process. At exactly 12:30pm, all of the individuals that she and other volunteers have previously screened during earlier phone calls—typically more than 100 people each week—will dial into the assistance line. The first 15 people who get through to the volunteers on duty will receive as much help as St. Vincent de Paul can provide them. The rest will have to hang up and try again at 12:30pm the following Saturday.

"The demand for assistance has increased significantly because of the pandemic," Navaro says. "We hear from so many families who are struggling because of job losses due to COVID, single moms who have to stay home with children because school isn't in session, and adult children who stay home to care for their parents."

According to Navaro, the volume of calls and the needs of individuals have increased so much and overwhelmed local organizations like St. Vincent de Paul that it's nearly impossible to keep up. St. Vincent serves a wide range of people, from 18-70+ years of age, who are falling behind on utility bills and other standard expenses. When possible, the organization issues up to $300 in funds directly to Duke Energy, the local utility provider, to help the individual get caught up on their outstanding bills or avoid a shutoff to protect the health and wellness of these families in need.

"They're so grateful for the help," Navaro said. "They're good people, and a lot of them are working as hard as possible to get current on all of their bills. They have a real uphill battle. On a local level, it's hard to witness our neighbors at such desperate points. They don't know where else to turn."

The COVID-19 pandemic exacerbated challenges that America's low-income households have face for decades: increasingly difficult choices about how to use limited funds for household necessities. Built to address this crisis, the Low Income Home Energy Assistance Program (LIHEAP) celebrated its 40th year as an assistance program in 2021. The program is widely supporting by numerous organizations across the nation, including government officials, nonprofit social service agencies, and the two leading expert organizations: the National Energy Assistance Directors Association (NEADA) and the National Energy & Utility Affordability Coalition (NEUAC). And yet in its 40th year, the nation saw a program that is increasingly essential and continually underfunded. There exists an immense need to expand LIHEAP to support the millions of households, including those feeling the deep and lingering impacts of a global pandemic.

LIHEAP: 40 YEARS OF SERVICE

The Dilemma of 'Heat-or-Eat'

Across the United States, low-income households have to make difficult and critical decisions about how to use their available income every month. For many Americans, their wages put them in or near the poverty line. In 2022, a four-person household met the federal poverty guideline with an annual income of $27,750. The reality is that for these households, making decisions about paying rent and utilities, buying groceries, paying for transportation is often a difficult and scary decision. Without enough money to pay for all bills each month, these families often face the 'heat-or-eat' dilemma: deciding whether to put food on the table or keep a home safe with proper heating and cooling.

Since its inception in 1981, the LIHEAP has been on a mission to help families avoid this emotional and stressful dilemma. The program delivers critical short-term aid to our most vulnerable neighbors, including the working poor, individuals with disabilities, and the elderly living on fixed programs.

Extensive academic research has documented the broader impact of energy assistance, from the "heat-or-eat" dynamic seen in many lower-income households, to the health effects on children. LIHEAP continues to be critical in protecting millions of struggling American families. This is especially true during the peak winter heating and summer cooling seasons, when energy bills can comprise nearly 30 percent of a low-income household's monthly income, especially in substandard housing.

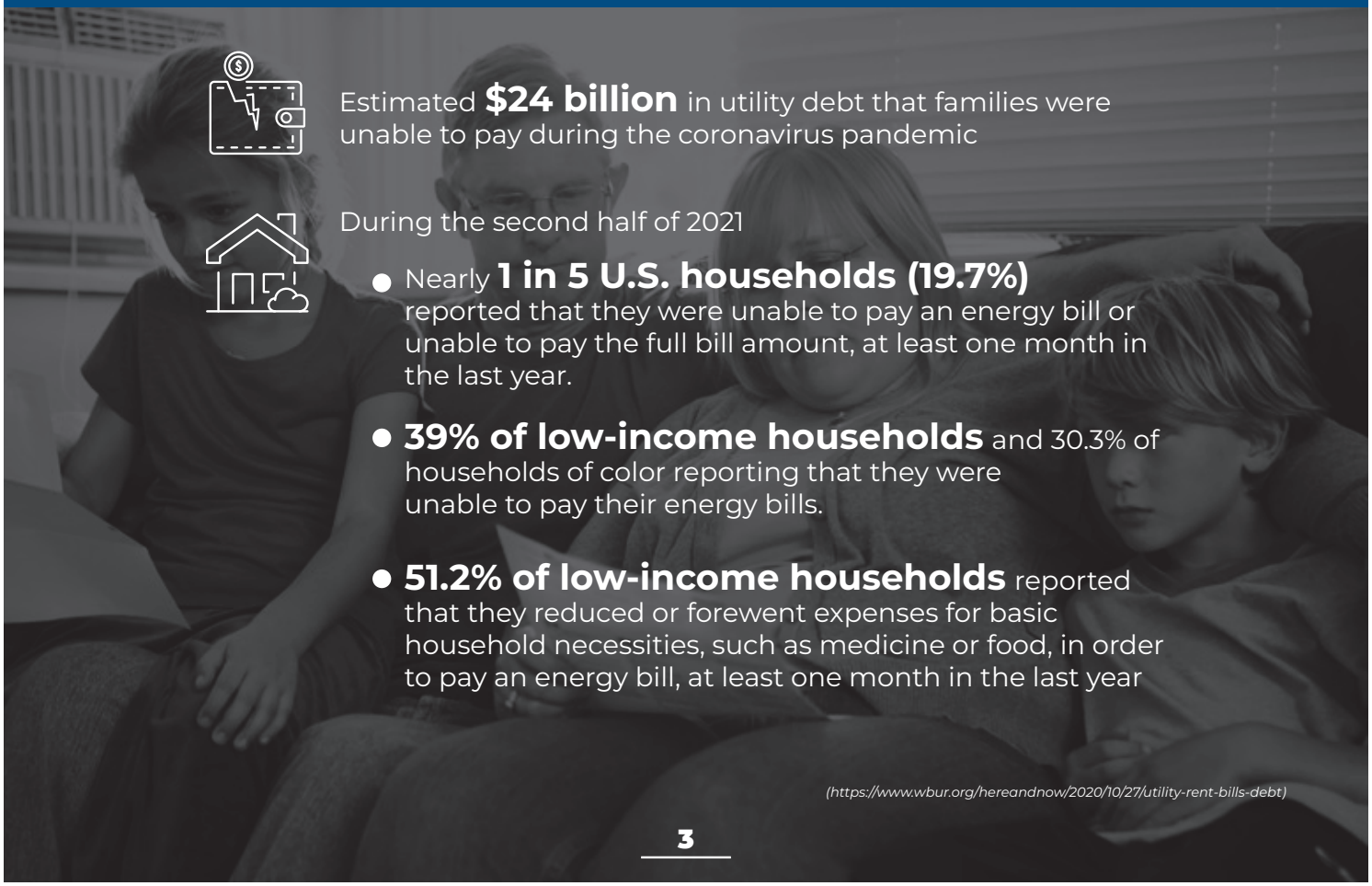
LIHEAP IN THE AGE OF COVID

LIHEAP, by design, serves households that qualify as low income. According to the LIHEAP Clearinghouse, an information source managed by the U.S. Department of Health and Human Services, states must set LIHEAP income eligibility standards within themaximum and minimums as established by law. Today, this LIHEAP statute determines that a household must have an income that "does not exceed the greater of 150 percent of the federal poverty guideline or 60 percent of the state median income level."

The COVID-19 pandemic brought a new economic crisis to American homes, in particular low-income homes. The official poverty rate in 2020 was 11.4%, up one percentage point from 2019 and the first increase in national poverty in five consecutive years, as reported by the U.S. Census Bureau. In 2020, nearly 37.2 million Americans lived in poverty, which is 3.3 million more Americans than in 2019. Black Americans continued to have the highest poverty rate of 19.5% in 2020, and Hispanics had a poverty rate of 17.0%. In addition, the median household income dropped 2.9% from 2019 to 2020, the first statistically significant decline since 2011.

What all of these statistics create is a high-level snapshot of very real, very personal challenges that millions of Americans face every day. The challenges existed before the pandemic, and they will exist after, too. But what can change is the way we address the need from external programs like LIHEAP. The critical nature of this program was demonstrated in many ways, but perhaps most telling was the shutoff moratoria in 2020 and 2021. Lawmakers and decision-makers united to protect what they knew was essential: living environments that are properly heated and cooled for the safety of those who reside inside.

As such, in May 2021, the inarguable necessity of LIHEAP funds was demonstrated by an additional $4.5 billion in supplemental funding. These funds were released for FY2021 under the American Rescue Plan of 2021 "for additional funding to provide payments" for LIHEAP.



Estimated **$24 billion** in utility debt that families were unable to pay during the coronavirus pandemic

During the second half of 2021

- Nearly **1 in 5 U.S. households (19.7%)** reported that they were unable to pay an energy bill or unable to pay the full bill amount, at least one month in the last year.
- **39% of low-income households** and 30.3% of households of color reporting that they were unable to pay their energy bills.
- **51.2% of low-income households** reported that they reduced or forewent expenses for basic household necessities, such as medicine or food, in order to pay an energy bill, at least one month in the last year

(https://www.wbur.org/hereandnow/2020/10/27/utility-rent-bills-debt)

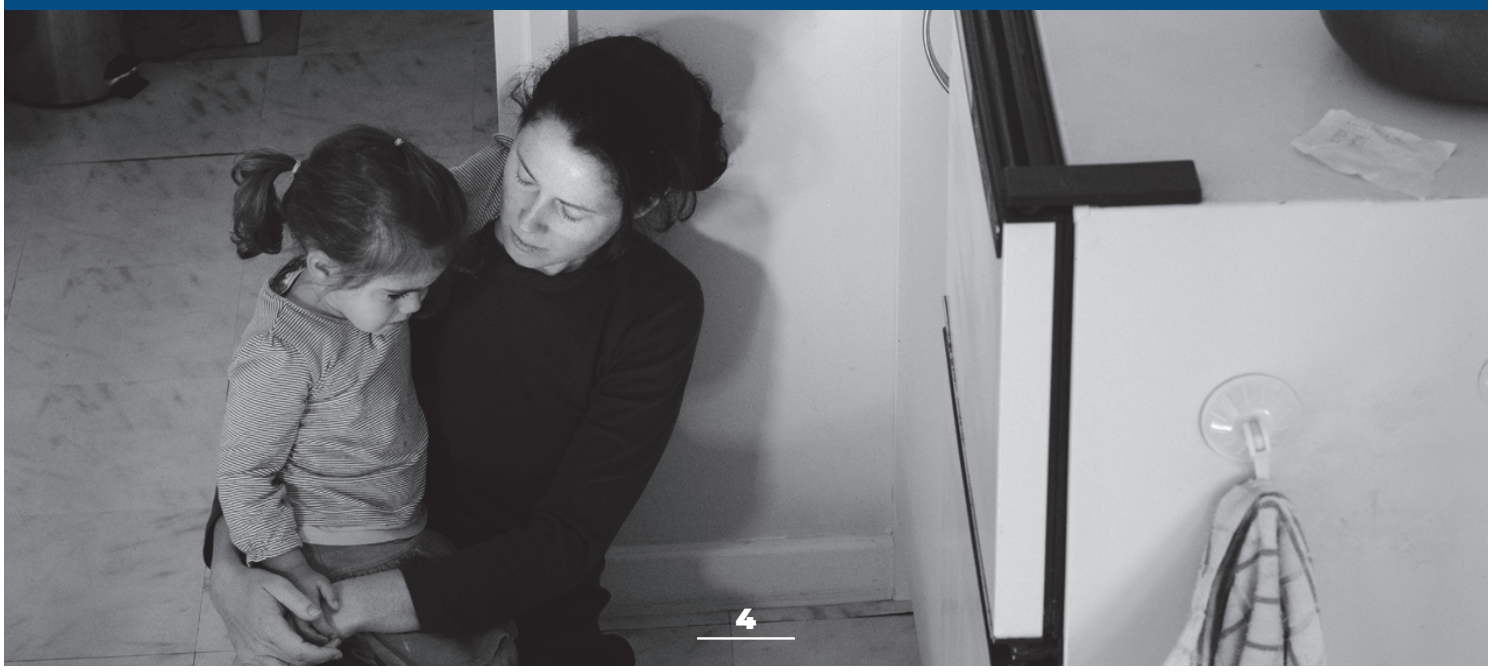
In a 2016 report by Pew Charitable Trusts, nearly 71 percent of Americans surveyed indicated an inability to save money because of unexpected expenses, with more than 26 percent of individuals reporting that this inability to save happens most months or just about every month. When paired with an economic downturn as seen during the COVID-19 pandemic, saving money is no longer the most pressing financial concern for many low-income households. Rather, simply paying bills for daily needs, like utilities and food, becomes the primary focus for many individuals.

With 1 in 5 of all U.S. households (18.6%) reporting that they kept their home at a temperature that felt unsafe or unhealthy for at least one month in the past year, the pandemic-era pressure creates a troubling outlook for low-income households. Indeed, the same report found that 1 in 4 households of color (24.6%) and 1 in 3 low-income households (32.1%) reported that they kept their home at a temperature that felt unsafe or unhealthy, at least one month in the last year.

As low-income households experience increasing pressure to finance core needs, temporary funding from LIHEAP becomes a method by which families are able to maintain safe household environments, particularly for those families with children, seniors and individuals with disabilities. And despite the increase in emergency funding during the pandemic, no long-term solutions have yet been put into place to further—and more thoroughly—meet the growing needs of low-income households.

Even as the nation recovers from pandemic and employment numbers rise, low-income families are left with less flexibility in their spending. In March 2020, state-mandated or voluntary utility shut-off moratoria were in place for 51% of the U.S. population (167 million people). The moratoria put in place in 2020 and 2021 were temporary measures to prevent shut-offs, but when they were lifted, low-income families faced growing bills and mounting debts amounting to more than a year's worth of utility bills that are left outstanding. In 2021, it is estimated that 3.4 million were disconnected from energy.

How do we, as a nation, justify the acknowledgement that utilities are essential elements of creating safe living environments; and yet, when it comes to funding the program that addresses this issue for low-income households, no action is taken to meet the need? Where do people like Kim Navaro, the local volunteer for Cincinnati's St. Vincent de Paul Society, tell individuals to go next?

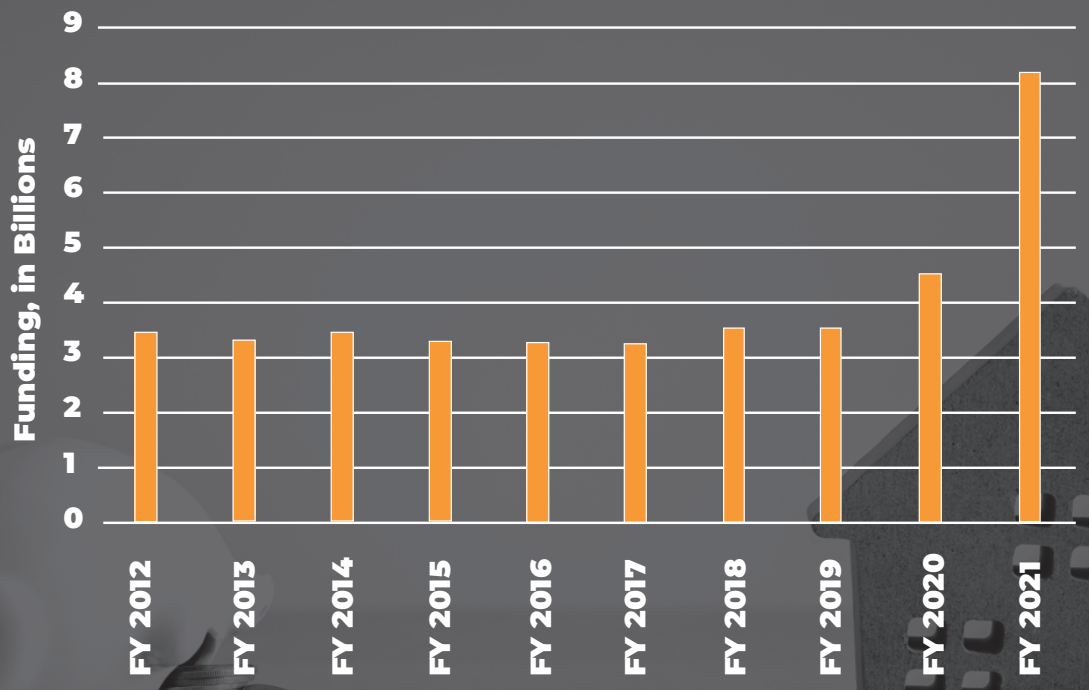


HOW LIHEAP WORKS

LIHEAP is one of the most critical components of the social safety net. The program provides heating and cooling assistance to roughly 6.7 million households. It is an exceptionally efficient and targeted program, with state block grants flowing to local agencies with specific clients on a short-term basis to prevent utility shutoffs or assistance with heating and cooling bills.

LIHEAP has nurtured a very positive, effective partnership between the federal government, state governments and the private sector. By leveraging private dollars to supplement federal dollars, LIHEAP has proven that successful relationships can exist between the government, businesses, gas and electric utilities and community based social service organizations.

Ten Years of LIHEAP Funding



This chart reflects Federal contributions only. State/local and philanthropic dollars are pooled with Federal money to complete the funding pool.

Initial FY 2022 Funding Release of LIHEAP Block Grant Funds to States and Territories under the Extending Government Funding and Delivering Emergency Assistance Act (Public Law 117-43)

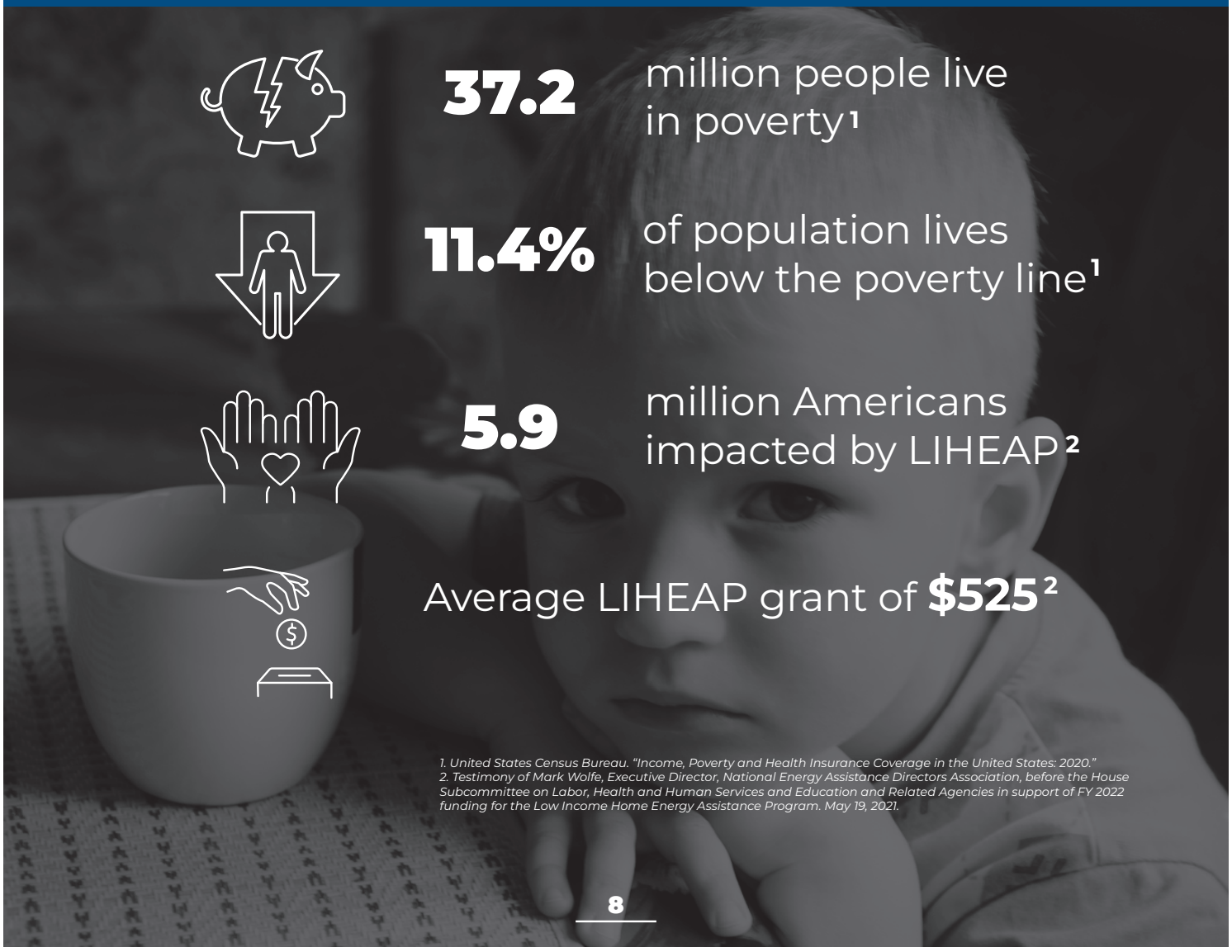
STATE/TERRITORY	NOVEMBER 1, 2021 RELEASE	TRIBAL SET-ASIDES	TOTAL RELEASE NOVEMBER 1, 2021 (INCLUDING TRIBAL AWARDS)
Alabama	$56,405,838	$342,537	$56,748,375
Alaska	$10,212,167	$7,196,715	$17,408,882
Arizona	$26,214,830	$1,252,113	$27,466,943
Arkansas	$29,809,772		$29,809,772
California	$179,228,041	$701,495	$179,929,536
Colorado	$53,827,678		$53,827,678
Connecticut	$65,781,165		$65,781,165
Delaware	$12,187,981		$12,187,981
District of Columbia	$10,333,336		$10,333,336
Florida	$89,843,962	$14,126	$89,858,088
Georgia	$71,046,573		$71,046,573
Hawaii	$4,719,389		$4,719,389
Idaho	$18,929,749	$965,850	$19,895,599
Illinois	$155,362,999		$155,362,999
Iowa	$49,844,374		$49,844,374
Kansas	$33,327,874	$40,500	$33,368,374
Kentucky	$51,647,205		$51,647,205
Louisiana	$50,324,254		$50,324,254
Maine	$35,028,729	$1,329,119	$36,357,848
Maryland	$69,851,450		$69,851,450
Massachusetts	$120,460,943	$181,239	$120,642,182
Michigan	$146,524,923	$963,903	$147,488,826
Minnesota	$106,248,005		$106,248,005
Mississippi	$33,175,107	$67,841	$33,242,948
Missouri	$75,090,892		$75,090,892
Montana	$19,256,528	$4,081,082	$23,337,610
Nebraska	$29,208,738	$16,200	$29,224,938
Nevada	$12,899,075		$12,899,075
New Hampshire	$25,192,436		$25,192,436
New Jersey	$112,665,012	$53,812	$112,718,824
New Mexico	$18,984,981	$977,004	$19,961,985
New York	$340,099,314	$184,620	$340,283,934
North Carolina	$96,321,906	$1,862,049	$98,183,955

STATE/TERRITORY	NOVEMBER 1, 2021 RELEASE	TRIBAL SET-ASIDES	TOTAL RELEASE NOVEMBER 1, 2021 (INCLUDING TRIBAL AWARDS)
North Dakota	$19,265,767	$6,086,686	$25,352,453
Ohio	$140,491,616		$140,491,616
Oklahoma	$38,316,431	$5,322,835	$43,639,266
Oregon	$33,704,628	$597,571	$34,302,199
Pennsylvania	$182,800,266		$182,800,266
Rhode Island	$21,871,003	$37,444	$21,908,447
South Carolina	$45,075,485	$9,392	$45,084,877
South Dakota	$17,374,542	$3,215,307	$20,589,849
Tennessee	$66,094,438		$66,094,438
Texas	$149,493,827		$149,493,827
Utah	$23,370,922	$331,148	$23,702,070
Vermont	$18,882,628		$18,882,628
Virginia	$88,899,086		$88,899,086
Washington	$57,425,673	$2,141,723	$59,567,396
West Virginia	$28,716,292		$28,716,292
Wisconsin	$95,638,461		$95,638,461
Wyoming	$9,029,976	$460,935	$9,490,911
Total to States	**$3,316,831,060**	**$38,439,244**	**$3,355,270,304**
Total to All Tribes	**$38,439,244**		
Territories			
American Samoa	$278,797		$278,797
Guam	$611,253		$611,253
Northern Mariana Islands	$212,305		$212,305
Puerto Rico	$15,172,934		$15,172,934
Virgin Islands	$578,007		$578,007
Total to Territories	**$16,853,296**		**$16,853,296**
GRAND TOTAL	**$3,333,684,356**	**$38,439,244**	**$3,372,123,600**

While states, local governments, utilities and charitable organizations have demonstrated their capacity to develop programs to address some energy assistance needs, collectively these programs cannot meet the demand for energy assistance, and this need continues to grow.

In his testimony before the House Subcommittee on Labor, Health and Human Services and Education and Related Agencies in support of FY 2022 funding for the Low Income Home Energy Assistance Program, Mark Wolfe, Executive Director of the National Energy Assistance Directors Association, noted that FY2021 funding levels enabled the "program to serve about 5.9 million households or about 16.7 percent of eligible households. About 70 percent of these households have at least one vulnerable and at-risk member who is elderly or disabled or have a child under the age of six." The average grant, Wolfe noted, was about $525 per family.

Most notably, Wolfe testified on the importance of LIHEAP for low-income families, who spend a disproportionate amount of their income (17.3%) on energy bills, which is more than five times the rate for non-low-income houses.



1. United States Census Bureau. "Income, Poverty and Health Insurance Coverage in the United States: 2020."
2. Testimony of Mark Wolfe, Executive Director, National Energy Assistance Directors Association, before the House Subcommittee on Labor, Health and Human Services and Education and Related Agencies in support of FY 2022 funding for the Low Income Home Energy Assistance Program. May 19, 2021.

PROGRAM COMPONENTS

Basic Energy & Crisis Assistance

Federal funding is determined each Fiscal Year through the Congressional Appropriations process, beginning with the Labor HHS Appropriations Subcommittees in the House and Senate. The program itself is administered by U.S. Department of Health and Human Services. Program funds are allocated via block grants determined by a statutory formula. States may spend only 10 percent of allocated funds on administrative costs and may transfer up to 15 percent (25 percent with an approved waiver) of costs to support weatherization efforts. The remaining funds are passed on to low-income households through direct grants.

LIHEAP has been operating under an annual authorization of up to $5.1 billion per year, although the program has only been fully funded in the Appropriations process once in its history. In moments of crisis – including the pandemic – supplemental funds have been pooled with traditional Appropriated funds to create a larger funding pool.

The LIHEAP statute authorizes HHS to assist eligible households in meeting the costs of home energy, which are defined as a source of heating or cooling in residential dwellings. Households are eligible under Federal standards when incomes do not exceed the greater of 150 percent of the poverty level for their state or 60 percent of the state median income. However, states may set income limits as low as 110 percent of the poverty level. The law requires benefits to be targeted to households with the highest energy costs in relation to income and household size.

The Emergency Contingency Fund

The Emergency Contingency Fund historically was used to supplement regular appropriations because some winters are worse than others, summers can be accompanied by prolonged heat waves and emergencies in certain regions may require flexibility in meeting needs beyond the formulas established under the program.

Congress permanently authorized emergency contingency funding at $600 million in FY1994, and they have remained authorized at that same level. Although overall appropriations have declined, Congress has not provided contingency funds in recent budget cycles in an effort to provide states more certainty around the amount of formula funds that would be available in each program year. However, program advocates have clarified the overarching need for all funding available to be directed to state programs. This distribution of funds allows states and organizations to better assist individuals households in need who qualify for the program. In both FY2020 and FY2021, the emergency contingency fund was $0.

Weatherization

States may allocate up to 15 percent of their basic grant allocation for low-cost residential weatherization or other energy related repair and up to 25 percent if they meet certain conditions and obtain a waiver from HHS. The weatherization program reduces the heating and cooling costs for low-income families by improving the energy efficiency of their homes and thereby improves their health and safety.

Planning for Distribution

Federal spending is designed to work under a fairly coherent process: the White House presents a budget blueprint to Congress; House and Senate Appropriations Committees determine spending levels for each Federal program; then these are all reconciled into spending bills that fund the government. Unfortunately, this process, known as "regular order," has not functioned in well over a decade. Instead, every year Congress passes a series of continuing resolution, known generally as a CR, as a means to keep government running while Congress and the White House finalize spending levels for the rest of the fiscal year.

For LIHEAP Administrators, this creates a particular challenge, as there can be significant uncertainty about how much funding will be available during the critical winter months.

Cold weather states traditionally spend more than 70 percent of the LIHEAP funds during the first two quarters of the federal fiscal year. While policymakers informally established a special "seasonality" consideration for LIHEAP and other programs that use their funds disproportionately during this period, the continuing resolution still affects states' ability to plan properly until there is certainty in the final level appropriated.

Another approach would be to return to the "Advanced Funding" model that was in place until FY2002. Advanced Funding sets funding levels a full year in advance, meaning program administrators would have much more time to accurately plan how to spend their state allocation.

MEETING THE NEED

Elderly, Disabled, Children

Many households receiving heating assistance include elderly residents, individuals with disabilities, and/or children. According to data released by HHS and reported by the Congressional Research Service, of all households served by LIHEAP, approximately 29 percent had at least one member 60 years of age or older; 31 percent had at least one member with a disability; and 23 percent included at least one child five years of age or younger.

Native American Tribes

As of FY2014, 153 Native American tribes and tribal organizations located in 22 states received funding through LIHEAP. The funds come out of the gross allotment for each state. Several tribes can form a consortium to administer the funds. The FY2014 tribal set-aside from regular block grant funds was nearly $5 million.

Veterans

Veterans make up nearly 20 percent of all recipients of LIHEAP funds. According to the U.S. Census Bureau's 2015 American Community Survey, there are approximately 1.3 million Veterans living in poverty. More than half a million of these Veterans also have a disability, which further complicates their ability to get or maintain jobs for supplemental income. For decades, homelessness among Veterans has been a growing concern, and eradicating Veteran homelessness has been a leading priority for recent presidential administrations. Among several factors indicated as a method of preventing eviction, many cities' homelessness prevention programs specifically note the importance of maintaining good standing with utilities. This reinforces the ongoing need to support Veterans through important programs like LIHEAP.

$4.7 billion: the minimum level of LIHEAP funding requested to serve those in need [3]

19% of eligible households are served by LIHEAP [4]

The people affected: [4]

153 Native American Tribes
31% individuals with disabilities
29% elderly
23% children
20% veterans

3. National Energy & Utility Affordability Coalition House FY2022 Appropriations Letter.
4. LIHEAP Clearinghouse Tribal Data: liheapch.acf.hhs.gov

A Framework for the Future: Policy Recommendations

In a deeply divided Washington, DC LIHEAP is a bit of an anomaly with near universal support for its mission and respect for the practitioners who administer the program.

With that said, program experts have specific recommendations for how this deeply admired program can be even better.

Annual Funding

Put simply, LIHEAP needs a greater annual Appropriation. While program supporters acknowledge and respect new investments in core services like water and broadband, we must recognize that LIHEAP has been underfunded for years. LIHEAP experts like NEADA and NEUAC are evaluating a wide range of funding proposals, with advocates supporting a modernization efforts that could see funding requests all the way from the current authorization of $5.1 billion up to $40 billion.

The key question for policymakers is how to define eligibility. The program can continue to operate at a high level with marginal increases in Federal funding that would allow all states to maintain robust investments. Similarly, LIHEAP practitioners welcome a conversation about how LIHEAP fits into a more expansive social safety net.

The most important, non-negotiable emphasis is the need for more robust program funding across the board.

Delivery of Services

In keeping with LIHEAP's evolution from a regional to a national program, states can improve delivery of services, especially in areas where the program is relatively new. States are eager to share best practices, engage more effectively with the public, track and evaluate metrics of success and maximize LIHEAP's role in a holistic approach to households in need. Additional flexibility in how states can invest LIHEAP funds can strengthen the overall program infrastructure and maximize return on investment for our collective tax dollars.

Advanced Funding

Congress should consider reestablishing Advanced Funding for LIHEAP, giving program administrators the necessary lead time to make decisions on how to best allocate resources and engage with the public. A combination of a robustly funded multi-year commitment with flexibility to invest targeted dollars in response to economic or weather-related crises could strike a proper balance.

This report was created in support of LIHEAP.org, a website and informational resource managed by Bracy Tucker Brown and supported by a grant from Michigan Energy First.

Fueling a renewable energy future

Shifting from fossil fuels to renewable resources and new technologies is at the center of our goal to evolve our energy supply and address climate change. Do we have a lot of work ahead? Yes. We are at the beginning stages of developing renewables for the gas system.

As our nation's electric system continues to work to increase wind and solar generation from 14% annually [1], we also need to aggressively accelerate development of renewables for our pipeline networks.

A diverse energy system– with renewable electrons delivered over wires and renewable molecules delivered underground provides a hedge against potential reliability risks while supporting shared climate goals.

What is renewable natural gas?

Renewable natural gas (RNG) is not a fossil fuel and does not add more carbon dioxide into the atmosphere. RNG is derived from biogas, which is produced from decomposing organic waste from landfills, agricultural waste and wastewater from treatment facilities, that has been captured and cleaned for the pipeline. [2]

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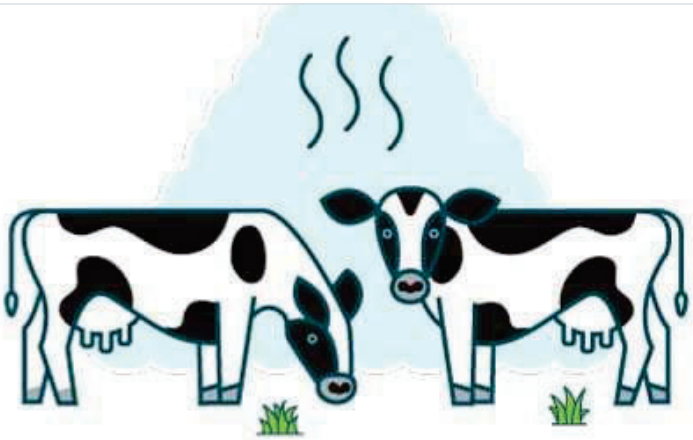

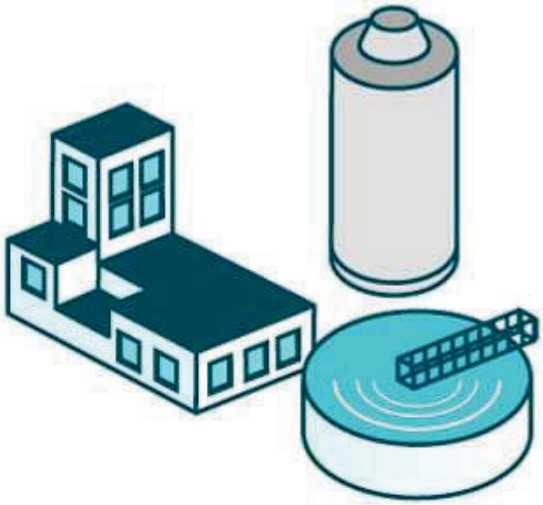

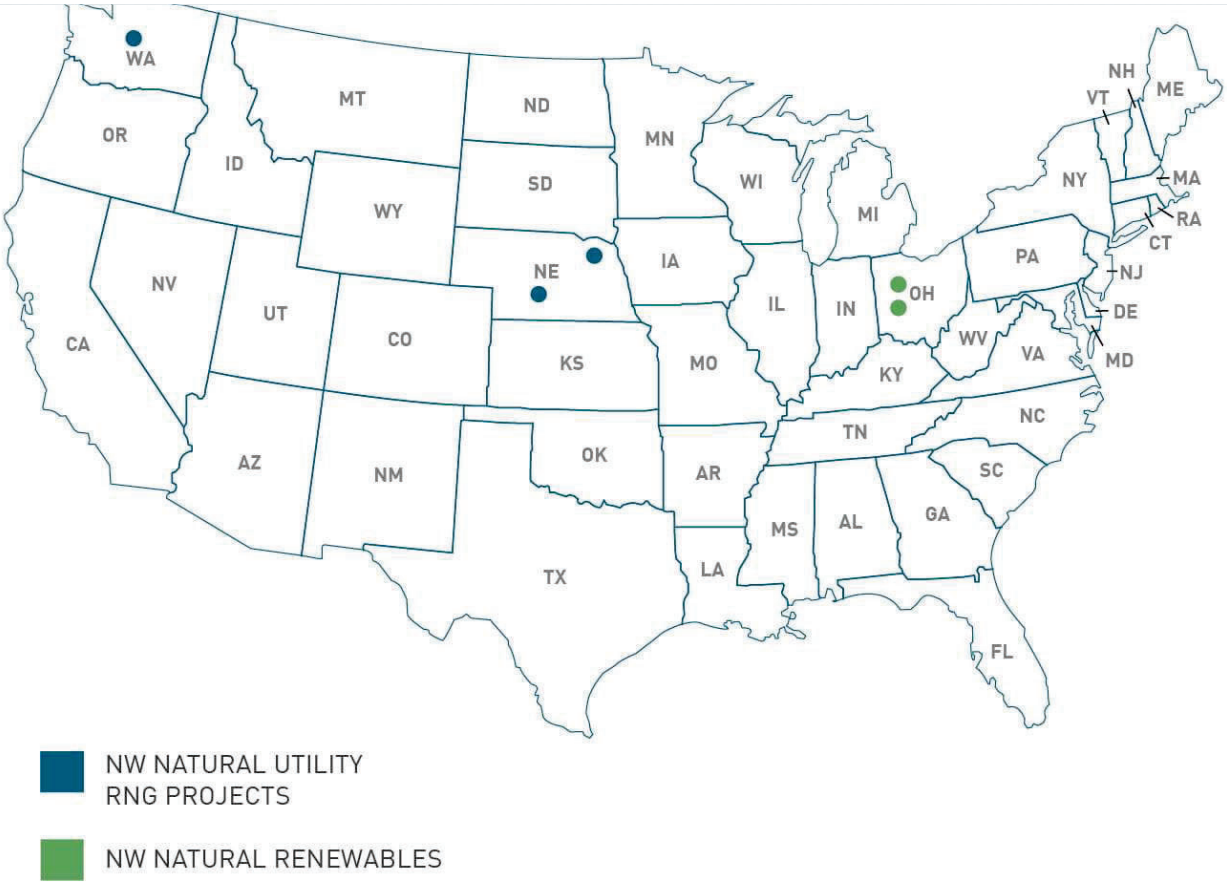

Our renewable natural gas projects

Today our system is making it possible for the first RNG projects in our region to deliver their low-carbon fuel, primarily for the transportation sector. We've also started delivering small volumes of RNG to our customers. We have a team focused exclusively on securing supplies of RNG for our customers. It's an important step on our journey to transition our business, but there's far more to do and we're going to need policy support to get there.

Agricultural Waste

Food Waste

Wastewater

Agricultural Waste

Shell New Energies: The Shell New Energies Junction City facility in Oregon uses locally sourced cow manure and excess agricultural residues to produce RNG. It began sending RNG through NW Natural pipelines in December 2021. The facility supports the local economy and helps farmers manage agricultural waste, reduce expenses and protect local air and water quality.

Food Waste

BP Products North America: NW Natural is purchasing Renewable Thermal Certificates (RTCs) generated by a facility in the Western U.S. that produces RNG from organic waste which includes food scraps, liquid waste and manufacturing food waste.

Landfill

BP Products North America: Through a long-term agreement with BP Products North America, NW Natural is purchasing the environmental attributes, or Renewable Thermal Certificates (RTCs), generated by landfills throughout the country.

Wastewater

Anew Climate: NW Natural is purchasing the environmental attributes, or Renewable Thermal Certificates (RTCs), generated by an RNG facility at a wastewater treatment plant in New York City.

MWMC: In November 2021, the Metropolitan Wastewater Management Commission's treatment plant in Eugene became the first public agency in Oregon to produce RNG. Nearly all of the biogas from the facility's anaerobic digesters that stabilize and treat solids is “scrubbed” and then injected into NW Natural's system. RNG also provides the MWMC with potential for an additional revenue source, by selling the gas and its renewable fuel credits to an off-taker that will use it for fueling vehicles.

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Senate Bill 98

Find out about the groundbreaking Oregon legislation that makes this progress possible.

SB 98 details +

Answers to customer questions about RNG

Is RNG in use today? +

Is there enough RNG? +

Is all of that RNG available now for residential gas use? +

What role does RNG play in the clean energy transition? +

What progress has been made to purchase RNG for customers? +

How has regulatory uncertainty affected NW Natural's ability to purchase RNG? +

Will NW Natural continue to pursue RNG? +

How does NW Natural evaluate where to purchase RNG from? +

Is RNG considered a "carbon neutral" or "zero-carbon" resource? +

Why is NW Natural pursuing RNG for the gas system and not electrification? +

No power? No problem.

Find out how you can depend on natural gas during a power outage.

Watch now >

No-cost, low-cost efficiency tips.

Read tips that can help you improve energy efficiency and lower your monthly bill.

See tips >

Smart Energy.

Let's work together to help address climate change.

Learn More >

Can I get gas?

Find a contractor

Use our tool to find a NW Natural preferred contractor.

Search

Register your account online.

View and pay bills, see gas use, and compare use over time.

Register

Access Information For All YCAP Services
Información de acceso para todos los servicios de YCAP

YCAP

NEED HELP?/
NECESITAS
AYUDA

ACCESS ALL YCAP SERVICES/ACCEDA A TODOS LOS SERVICIOS DE YCAP

ENERGY ASSISTANCE/ASISTENCIA ENERGÉTICA

FOOD/ALIMENTO

RENTAL ASSISTANCE/ASISTENCIA DE ALQUILER

SHELTER SERVICES/SERVICIOS DE REFUGIO

YOUTH PROGRAMS

COMMUNITY RESOURCES/RECURSOS DE LA COMUNIDAD

HAGA CLIC AQUÍ PARA VER LA VERSIÓN EN ESPAÑOL DE LA PÁGINA

ENERGY ASSISTANCE

QUESTIONS ABOUT ENERGY ASSISTANCE 503-687-1480

ENERGY ASSISTANCE HOTLINE 1-855-216-5289 EXT. 1480

Para asistencia en español, por favor de llamar 503-687-1480

Please click below to have an application mailed to you:

APPLICATION REQUEST FORM

ENERGY BILL ASSISTANCE

Energy and heating is a necessary aspect of shelter. Deficiencies in home heating pose a threat to life, health, and safety. The purpose of Energy Assistance is to provide support to eligible households to offset residential energy costs. Below are resources that may provide assistance to eligible applicants.

LIHEAP, OEAP, and OLGA require a gross annual income at or below $70,790 for a family of four. Complete income guidelines and additional requirements are available by clicking the orange buttons below the program descriptions.

STATUS OF ENERGY ASSISTANCE

LIHEAP (LOW INCOME HOME ENERGY ASSISTANCE PROGRAM)

LIHEAP is available to customers that meet the income guidelines. Assistance may be directed to the primary heat source in the home. Applications are processed on a first-come-first-served basis. Application packets are anticipated to be available the first week of October for households having either a senior (60 or older) and/or disabled household member(s). Pending funding availability, general public households will be placed on a referral list starting in December and follow the department's application release processes. Applications will continue to be accepted through the heating season until all funds have been utilized.

For additional questions or to be placed on the referral list, please call **503-687-1480**, or use the online form above to be placed on the application request list.

OEAP (OREGON ENERGY ASSISTANCE PROGRAM)

PGE customers only.
Applications are processed on a first-come-first-served basis. Please call **503-687-1480,** or use the online form above to be placed on the application request list. OEAP qualifying criteria includes income eligibility. Priority status may be given to households with no power, medical equipment or a shut-off notice. YCAP receives a monthly allocation to serve a limited number of households.

OLGA (OREGON LOW-INCOME GAS ASSISTANCE)

NWNG customers only.
Applications are processed on a first-come-first-served basis. Please call **503-687-1480,** or use the online form above to be placed on the application request list. Applications will be accepted until funds are exhausted. OLGA qualifying criteria includes income eligibility and an active

account with NWN. YCAP receives a monthly allocation to serve a limited number of households. Once these funds are spent, applications may be placed on a list until additional funding becomes available.

ELIGIBILITY INFORMATION FOR LIHEAP, OEAP, AND OLGA

WEATHERIZATION

The Weatherization program provides free weatherization services to income-eligible residents (homeowners and renters) of Yamhill County. The goal is to lower energy usage in order to lower utility costs.

Income eligible clients must be at or below 200% of Federal Poverty. Once deemed eligible for services, an energy audit will be conducted to identify and prioritize cost-effective weatherization measures.

To request an application or appointment, please call **503-687-1483**.

Weatherization measures may include:

GENERAL HEAT WASTE

Reduce air infiltration in ways such as: replace broken window pane, re-glaze windows, interior caulking, install new weather-stripping on windows and doors, and insulate water pipes.

EFFICIENCY UPGRADES

LED lighting, low-flow shower, and faucet kits.

HEATING SYSTEMS

Pressure test forced-air system, air seal and insulate supply and return duct system. Install as appropriate: flame retention burners, electronic ignition devices, and heating system repairs.

ATTIC INSULATION

Bring ventilation up to code, provide protective barriers around heat-producing devices, and insulate to cost-effective level.

WALL INSULATION

Blow loose-fill insulation into wall cavities to reduce heat loss and air infiltration.

FLOOR INSULATION

Provide vapor barrier on the ground, and install fiberglass batt insulation in the joist cavities.

WINDOWS

Based on results from the home assessment, window treatments may not be cost-effective.

SKIRTING

Install appropriate materials around the perimeter of the dwelling unit to control airflow in the

crawl space.

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ENERGY EDUCATION

Consultation with the Energy Professionals to maximize energy savings.

ELIGIBILTY INFO

CLICK HERE TO REQUEST AN ENERGY ASSISTANCE APPLICATION FORM

EASY WAYS TO REDUCE ENERGY:

Check your furnace filter. A dirty filter will make the furnace work harder, and raise your energy bill. It is a good idea to check your filter every month.

Vacuum heat registers to improve air circulation. Be sure registers are open in all rooms.

Keep furniture and drapes away from the heating registers to let air circulate. Keep interior doors open.

Use bathroom and kitchen fans to keep the humidity down and prevent the growth of mold and mildew.

Turn off lights and electronics, such as TVs and computers when not in use. A color TV or computer left on at all times can cost $7 to $10 per month.

Wash full loads of laundry. Always use cold rinse setting.

Use compact fluorescent or LED bulbs. They are four times more energy-efficient than incandescent bulbs and provide the same lighting.

Turn down the heat at night and when you are away from home

SPOTLIGHT STORY

> *Thank you so very much. Due to health problems I have been unable to work for 6 months and am caregiver to my special needs daughter. My husband's hours at work had been cut and we have gotten deeper in the hole until we almost lost our utilities. We are so thankful you provide help to the needy. God bless you for all you do and may you continue in this good work for many years.*

— Energy Client

‘It’s a bloodbath’: Massive wave of job cuts underway at US health agencies

By Nick Valencia, Brenda Goodman, Meg Tirrell, Tami Luhby and Sean Lyngaas, CNN

8 minute read Updated 11:06 AM EDT, Wed April 2, 2025

Notices about job cuts are going out to some employees at US health agencies. Kayla Bartkowski/Getty Images

CNN — A massive wave of job cuts got underway at US health agencies Tuesday, with some employees receiving early-morning emails saying their jobs were eliminated and some unable to access the building when they arrived at work.

It was not immediately clear how many employees had received notice Tuesday morning. The US Department of Health and Human Services has not responded to CNN’s request for comment.

RELATED ARTICLE

HHS cuts 10,000 employees in major overhaul of health agencies

HHS Secretary Robert F. Kennedy Jr. said last week that 10,000 full-time employees would be cut on top of thousands who had already left and probationary employees currently on leave. He said the changes would make fighting chronic disease the priority and reduce “bureaucratic sprawl.” Kennedy promised that the department would do more with less.

After weeks of worry from agency staffers, job cuts — known as a reduction in force, or RIF — were sweeping across offices at multiple agencies, hitting leadership, longtime staffers, scientists, administrators and communications staff. “It’s a bloodbath,” one US Food and Drug Administration employee said.

“These cuts to agency experts and programs leave our country less safe, less prepared and without the necessary talent and resources to respond to health threats,” Dr. Mandy Cohen, director of the US Centers for Disease Control and Prevention during the Biden administration, said Tuesday.

In a post on LinkedIn, former US Food and Drug Administration Commissioner Dr. Robert Califf said, “The FDA as we’ve known it is finished, with most of the leaders with institutional knowledge and a deep understanding of product development and safety no longer employed.” Califf told CNN on Tuesday that “If we let down our guard and don’t do a good job reviewing, we’re going to unleash some things that are really dangerous into the population. Unless there’s some super plan, there’s going to be an effect on safety, because it takes whole teams of people to monitor safety of products, and the timetables for product review will probably be delayed.”

Califf said he was dismayed to see how federal workers were being treated.

“This is a sad and inhumane way to treat people,” he said. “It’s different when you’re a company and you’re out of money and you can’t pay people, but the federal government can pay people and do things in an orderly, respectful fashion – and

RELATED VIDEO

Governor warns of loss of life amidst RFK Jr.'s major cuts at HHS

not have them end up in line trying to get to work and have their badges not work as a way to fire them."

Sens. Bill Cassidy, R-Louisiana, and Bernie Sanders, I-Vermont, of the Senate Health, Education, Labor, and Pensions Committee announced Tuesday that they were inviting Kennedy to a hearing April 10 about the restructuring of HHS.

"This will be a good opportunity for him to set the record straight and speak to the goals, structure and benefits of the proposed reorganization," Cassidy said in a statement.

Sanders was also among dozens of senators who wrote a letter to Kennedy on Tuesday to outline areas of the health care system that will be affected by the cuts and to request answers about the number of employees affected, the method of communication and any analysis on the impacts to programs and activities.

"You continue to deny visibility to the American public, despite your oft-repeated commitment to 'radical transparency.' You have promised that HHS will do more for the American people, at a lower cost to the taxpayer, yet you have not provided anything to substantiate these claims, despite repeated requests from Congress to do so," the letter says.

Kennedy said in a social media post that the agency is being "recalibrated to emphasize prevention, not just sick care."

"This is a difficult moment for all of us at HHS. Our hearts go out to those who have lost their jobs," he wrote. "But the reality is clear: what we've been doing isn't working."

Details start to emerge on cuts

The totality of the cuts was not clear Tuesday, with many workers waiting for emails — or waiting to get into buildings, uncertain whether their badges would work. Even supervisors weren't sure who was being eliminated, one senior official at the CDC said.

Cuts at the CDC slashed divisions that work on workplace health and safety, HIV, injury prevention, reproductive health, smoking and violence prevention, among others. Despite Kennedy's focus on chronic diseases, CDC employees described broad cuts at the agency's National Center for Chronic Disease and Health Promotion.

The offices at the CDC and the National Institutes of Health that handle Freedom of Information Act requests were also cut. The FDA lost many of its FOIA officers, but a few remained, including some who were working on litigation, according to a source familiar with the circumstances who spoke on the condition that they not not be named for fear of reprisal.

Several senior leaders at the CDC were reassigned to other roles, and some were told they would have to relocate. At NIH, Dr. Jeanne Marrazzo, director of National Institute of Allergy and Infectious Diseases, was also offered reassignment to the Indian Health Service and would have to move to an area such as Alaska, New Mexico or Minnesota.

RELATED ARTICLE

Is DOGE actually an agency? The answer could have major ramifications

At the Centers for Medicare and Medicaid Services, the entire Office of Equal Opportunity and Civil Rights – which handles issues of diversity, civil rights and a supportive work environment – was let go, according to a former HHS employee.

The notices sent to staffers in the office suggested that they contact the former director of the office if they had a complaint — but that director died late last year, Karen Shields, a former CMS executive, posted on LinkedIn on Tuesday morning. CNN has obtained a copy of the notice.

"The dissolution of the office is disturbing but was expected. The referral to a woman who died over four months ago is a result of a significant lack of collaboration and consultation with the career team at the agency who would have helped to prevent this disgrace," Shields wrote.

Also, CMS cut all or nearly all of the Office of Minority Health, the former HHS employee said. The website of the office, which aims to improve the health of racial and ethnic minority groups through health policies and programs, was not working Tuesday, although it had been operational as recently as Saturday, according to web archives.

The office, which was created by Congress, also focused on rural health, former CMS Administrator Chiquita Brooks-LaSure said Friday.

"We have health disparities, and we need to be measuring what is happening so that we can address those," she said, noting that the office looked at issues such as diet and diabetes.

At the FDA, staffers in the Office of New Drugs, the Office of Policy & International Engagement and the Office of Regulatory Programs were among those receiving notice. The agency's entire press office - the group that shares material with news media - received notice and was put on administrative leave, according to a person familiar with the cut who declined to be named because they weren't authorized to speak publicly about it.

RELATED ARTICLE

Job opportunities are shrinking and layoffs in the federal government just hit their highest level in four years

A RIF notice received by one FDA employee on Tuesday included performance ratings that were incorrectly low, meaning the severance pay offered was lower than it would be for the ratings they previously received, the employee told CNN.

Multiple other colleagues who received the RIF had the same issue, the FDA employee said, making them uncertain whether they should sign the inaccurate paperwork. The employee said they couldn't tell if the inaccuracy was deliberate or an honest mistake.

"Everybody's got families and mortgages and real-life concerns," the source said, speaking on the condition of anonymity because they were concerned that being named would hurt their job prospects.

Also terminated was the entire staff of the Low Income Home Energy Assistance Program, or LIHEAP, according to Mark Wolfe, executive director of the National Energy Assistance Directors Association. The program provides about $4 billion to help millions of Americans with their heating and cooling bills.

"It will definitely hamper program operations," Wolfe said, noting that he doesn't see how the agency can "allocate the remaining $387 million in funds for this year without federal staff. The program could well grind to a halt."

Staff of the HHS Administration for Children and Families – which provides support for child care, child welfare, early childhood development, family violence prevention, refugee resettlement, homeless teens and Head Start programs, among others – also received notice Tuesday.

"We're devastated for our colleagues and friends who have lost their careers, and we're really feeling primarily devastated for our programs that we care so much about. In the regional offices, we're the ones who work directly with the people — the states, the territories, the tribes, the people that we serve — and we're just abruptly cut off from that work and our relationships," said one employee in the administration who received notice Tuesday.

"Our concerns are that by gutting these offices, it can make child care less safe, less affordable."

Workforce to shrink by 20,000

HHS announced last week that its reduction in force would cut 10,000 full-time employees in addition to 10,000 employees who've left voluntarily, shrinking the workforce from about 82,000 full-time employees to 62,000. About 5,200 probationary workers who have been in their positions less than a year or two were also terminated last month. Most are on temporary administrative leave as their fate winds its way through federal courts.

HHS said last week cuts would include:

- 3,500 full-time employees at the US Food and Drug Administration, not affecting drug, medical device or food reviewers or inspectors
- 2,400 employees at the US Centers for Disease Control and Prevention
- 1,200 employees at the National Institutes of Health due to centralizing procurement, human resources and communications
- 300 employees at the Centers for Medicare & Medicaid Services

Kennedy announced the cuts as part of a sweeping reorganization that would move or cut several parts of the federal health workforce, including the creation of a new Administration for a Healthy America, which it said would combine the Office of the Assistant Secretary for Health, the Health Resources and Services Administration, the Substance Abuse and Mental Health Services Administration, the Agency for Toxic Substances and Disease Registry and the National Institute for Occupational Safety and Health.

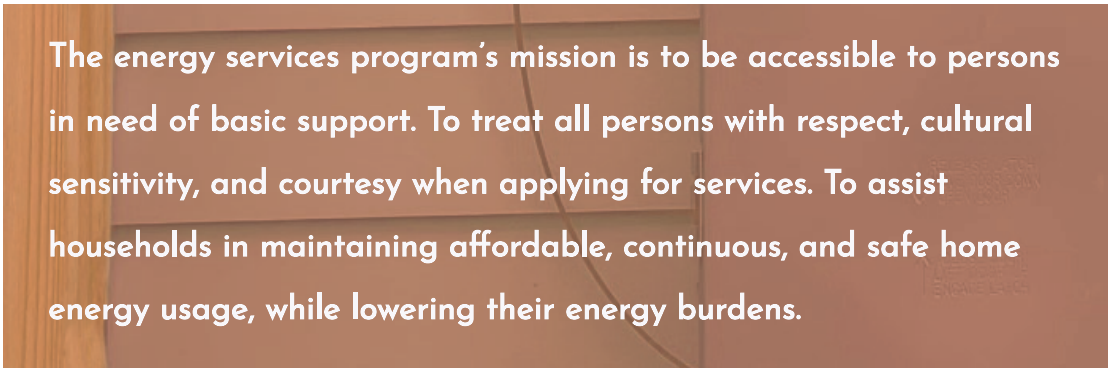
CNN's Ross Levitt and Rene Marsh contributed to this report.

Utility Assistance

Utility Assistance

Utility Assistance programs provide a variety of energy/utility bill assistance with electric, natural gas, pellets, wood, propane, oil, and furnace repair/ replacement. When funding is available, we may be able to assist with water.

Funds are available through a variety of sources. Households that are eligible to receive utility assistance also have the opportunity to attend an Energy Education workshop by our Weatherization department and could receive storm window and energy-saving kits.



Who We Serve

Our services are available to households with income levels at or below 60% of Oregon's State Median Income. Check the income guidelines for more details or reach out to your nearest office:

Energy Assistance Income Guidelines – FY2025

Household Unit Size	*Annual Gross Income*	*Monthly Gross Income*
1	$36,811	$3,067.58
2	$48,138	$4,011.50
3	$59,464	$4,955.33
4	$70,790	$5,899.17
5	$82,117	$6,843.08
6	$93,443	$7,786.92
7	$95,567	$7,963.92
8	$97,690	$8,140.83

Tillamook County

Tillamook CARES
2310 First Street, Suite 2
Tillamook, Oregon 97141
(503) 842-5261

Columbia County

Community Action Team
125 North 17th Street
St. Helens, Oregon 97051
(503) 397-3511
fax (503)397-3290
energy@cat-team.org

Clatsop County

Clatsop Community Action – CCA
364 9th St
Astoria, OR 97103
(503) 325-1400

Energy Assistance Income Guidelines – FY2025		
9	$99,814	$8,317.83
10	$101,938	$8,494.83
11	$104,062	$8,671.83
12	$106,185	$8,848.75
Each Additional Member	$2,123	$176.92

60% of State Median Income by Household Size For Use in Federal Fiscal Year 2025
Estimated State Median by Household Size-Source HHS

Energy and Utility Assistance Program Forms

- Application Checklist
- Client Satisfaction Survey
- CAT Internal Referral Form
- Medical/Unexpected Event Assistance Request
- Self-Employment Worksheet

Our Assistance Programs Include:

Low Income Home Energy Assistance Program (LIHEAP)

English

A federally funded program that supports households with energy costs for electricity, natural gas, oil, pellets, propane, and wood. It also offers assistance with minor furnace repairs or replacements, ensuring homes stay safe and warm during harsh weather.

Oregon Energy Assistance Program (OEAP)

State-funded assistance for Pacific Power customers, focusing on maintaining uninterrupted energy service for those who qualify.

OLGA & GAP Programs

These resources are designed to assist Northwest Natural customers, offering tailored support for natural gas costs.

Medical/Unexpected Events Assistance

For families facing emergencies due to medical needs or other unexpected events, this program helps cover energy bills and even water-related costs, providing a safety net during challenging times.

Energy Education

Practical advice to help families reduce energy use and costs.

Self-Help Weatherization Materials

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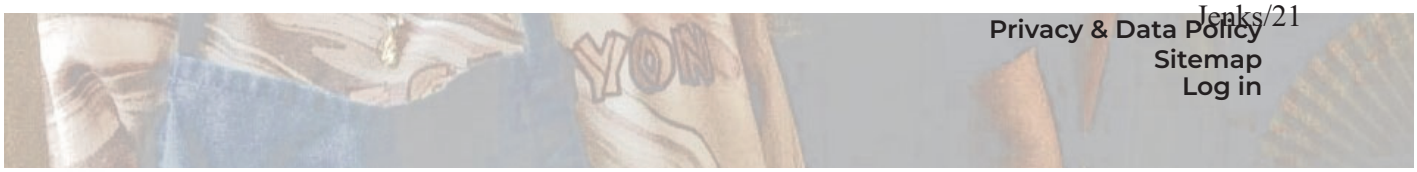

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

Stipulating Parties

Joint Testimony of Zachary Kravitz, Matt Muldoon, Bob Jenks, and Bradley Mullins

in Support of First Partial Stipulation

EXHIBIT 100

July 10, 2025

I. INTRODUCTION AND SUMMARY

Q. Who is sponsoring this testimony?

A. This testimony is sponsored jointly by Northwest Natural Gas Company, dba NW Natural ("NW Natural" or "Company"), Staff of the Public Utility Commission of Oregon ("Staff"), the Oregon Citizens' Utility Board ("CUB"), and the Alliance of Western Energy Consumers ("AWEC") (collectively, the "Stipulating Parties").

Q. Please provide your names, positions, and qualifications.

A. My name is Zachary D. Kravitz and my current position is Vice President, Regulatory Affairs and Resource Planning for NW Natural. My qualifications are provided in NW Natural/100.

My name is Matt Muldoon and I am a manager employed in the Accounting and Finance Section of the Commission's Energy Program. My qualifications are provided in Exhibit Staff/501.

My name is Bob Jenks and I am the Executive Director of CUB. My qualifications are provided in Exhibit CUB/101.

My name is Bradley Mullins and I am a consultant with MW Analytics, appearing on behalf of AWEC. My qualifications are provided in Exhibit AWEC/101.

Q. What is the purpose of this Joint Testimony?

A. This Joint Testimony describes and supports the First Partial Multi-Party Stipulation Regarding Revenue Requirement ("First Stipulation") filed in this docket on June 23, 2025. The First Stipulation resolves all issues among the Stipulating Parties, except those listed in Paragraph 3 of the Stipulation, which will continue to be litigated in this proceeding or—in the event of a future settlement in this proceeding—incorporated in a separate stipulation. The Stipulating Parties

support all terms in the First Stipulation. Climate Solutions, Coalition of Communities of Color, Verde, Sierra Club, and Oregon Environmental Council (collectively, the "Coalition") is also a party to this docket and does not join the First Stipulation, but the Stipulating Parties are authorized to represent that the Coalition does not oppose the First Stipulation.

II. BACKGROUND

Q. Please summarize the background and context of Docket No. UG 520.

A. On December 30, 2024, NW Natural filed a request for a general rate increase (the "Initial Filing"). The Company developed the case using the Test Year comprised of the 12 months ending October 31, 2026 ("Test Year") and historical base year of the 12 months ended December 31, 2024 ("Base Year").[1] The Company's Initial Filing requested a revision to customer rates that would increase the Company's annual Oregon jurisdictional revenues by $59.4 million, which would have resulted in an approximate 5.79 percent increase to current customer rates (equal to a 9.45 percent increase to current margin revenues).[2] In the Company's Reply Testimony filed on May 21, 2025, the Company updated its requested increase to Oregon jurisdiction revenues to $59.3 million.[3]

Q. Have the Stipulating Parties and the Coalition conducted discovery in this proceeding?

[1] Initial Filing, Executive Summary at 3.
[2] Initial Filing, Executive Summary at 1; NW Natural/1603, Wyman/1.
[3] NW Natural/1700, Rush-Kravitz/6; NW Natural/3200, Walker/27.

A. Yes. Since the Initial Filing, NW Natural has responded to 806 data requests from Staff, CUB, AWEC, and the Coalition, and has provided updates to its data responses during the pendency of this case.

Q. Did Staff and intervenors file testimony and propose adjustments to NW Natural's Initial Filing?

A. Yes. According to Administrative Law Judge ("ALJ") Spruce's February 14, 2025, Memorandum adopting a procedural schedule, Staff, CUB, AWEC, and the Coalition filed Opening Testimony on April 2, 2025, in which they proposed adjustments to NW Natural's Initial Filing. While each of the parties took different positions and made different arguments, collectively, they proposed adjustments to NW Natural's proposed revenue requirement, cost of capital, and rate spread and rate design, as well as certain changes to Company practices. NW Natural filed Reply Testimony on May 21, 2025, responding to the proposed adjustments and other issues raised in the parties' Opening Testimony.

Q. Have the parties to this proceeding engaged in settlement discussions?

A. Yes. All parties engaged in scheduled settlement discussions on April 22, 2025, and June 11, 2025, with settlement discussions ongoing through June 17, 2025. The parties convened an additional settlement conference on June 17, 2025. As a result of the settlement discussions, the Stipulating Parties reached a partial settlement resolving all issues in this proceeding except those issues specifically excluded from the scope of the First Stipulation under Paragraph 3 of the First Stipulation, which will continue to be litigated or—in the event of a future settlement

in this proceeding—incorporated in a separate stipulation. The First Stipulation memorializes the Stipulating Parties' agreements.

Q. Although the Coalition did not join the First Stipulation, did the Coalition participate in settlement discussions?

A. Yes. The Coalition participated in all of the settlement discussions. While the Coalition ultimately did not join the First Stipulation, the Coalition does not oppose the First Stipulation.

Q. Please provide an overview of the First Stipulation.

A. The Stipulating Parties intend the First Stipulation to be a comprehensive settlement of all revenue requirement issues in this proceeding. The First Stipulation also addresses other issues among the Stipulating Parties, including the creation of a regulatory asset associated with the retirement of the GC 500 Mist Compressor, NW Natural's agreement to file officer attestations regarding capital in service, implementation of the Company's updated depreciation rates, and a one-day modification to the rate effective date. Following the Stipulating Parties' agreement to the First Stipulation, the issues that will continue to be litigated—and, if a settlement is reached, included in a separate stipulation—are identified in Paragraph 3 of the First Stipulation.

Q. What issues are identified in Paragraph 3?

A. The issues listed in Paragraph 3 are:

a. Rate Spread (AWEC/100; Staff/1700);
b. Rate Schedule 27 (Coalition Intervenors/100);
c. Load Forecasting (Staff/1700);
d. Regulatory asset for plant retired due to electrification (CUB/100);
e. Analysis of non-pipeline alternatives (Coalition Intervenors/200);
f. Electrification and thermal energy network pilots (Coalition Intervenors/200);

g. Research and Development Reporting (Coalition Intervenors/100);
h. Oregon Low-Income Energy Efficiency ("OLIEE") program funds for electric heat pumps (Coalition Intervenors/100); and
i. Low Income Home Energy Assistance Program ("LIHEAP") funding (CUB/100).[4]

III. ISSUES COVERED BY THE FIRST STIPULATION

Q. Please describe the Stipulating Parties' positions regarding the Company's revenue requirement.

A. The Stipulating Parties agree that the total increase to NW Natural's annual Oregon revenue requirement is $21.315 million.[5] The annual revenue requirement increase is based on the Stipulating Parties' agreement that the Company's Oregon-allocated increase to annual revenue requirement shall be reduced by a total of $37.991 million from the May 21, 2025, Reply Testimony update of $59.3 million, based on the adjustments to NW Natural's Initial Filing and Reply Testimony update described in further detail below.[6]

Q. Do the Stipulating Parties agree on all the methodologies employed to determine each adjustment?

A. No. The Stipulating Parties do not necessarily agree upon all the methodologies used to determine each adjustment included in the First Stipulation. However, the Stipulating Parties believe that the agreed-upon adjustments collectively represent a reasonable settlement of the issues in the First Stipulation, and that, taken together, the adjustments result in an overall revenue requirement that will produce rates that are fair, just, and reasonable. As such, the Stipulating Parties agree that

[4] First Partial Multi-Party Stipulation Regarding Revenue Requirement at 5-6 (June 23, 2025).
[5] First Partial Multi-Party Stipulation Regarding Revenue Requirement at 2.
[6] First Partial Multi-Party Stipulation Regarding Revenue Requirement at 2-3.

the First Stipulation is in the public interest and support the Public Utility Commission of Oregon's ("Commission") adoption of its terms.

A. Cost of Capital/Capital Structure

Q. Please describe the Stipulating Parties' agreement regarding Cost of Capital.

A. In its Initial Filing, NW Natural requested a capital structure of 52 percent common equity and 48 percent long-term debt, which represented a change from the capital structure of 50 percent common equity and 50 percent long-term debt that the Commission authorized for NW Natural in Order No. 24-359 in the Company's last general rate case, Docket No. UG 490.[7] The Company requested an overall rate of return ("ROR") on rate base of 7.658 percent, based on a 4.687 percent embedded cost of long-term debt and a 10.4 percent cost of equity.[8]

In Opening Testimony, Staff proposed a target capital structure of 50 percent equity and 50 percent long-term debt, and an overall ROR on rate base of 7.025 percent "for illustrative purpose[s] only."[9] Staff's overall ROR was based on an embedded 4.749 percent cost of long-term debt and an ROE of 9.30 percent, which was the "illustrative midpoint of Staff's range of reasonable ROEs," which was from 9.0 percent to 9.6 percent.[10] AWEC recommended a capital structure of 49 percent equity and 51 percent long-term debt, and an overall ROR on rate base of 6.898 percent, based on a cost of long-term debt of 4.69 percent and an ROE

[7] NW Natural/300, Wilson/2-3; *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 490, Order No. 24-359 at 4, 6 (Oct. 25, 2024).
[8] NW Natural/300, Wilson/3.
[9] Staff/500, Muldoon/38.
[10] Staff/500, Muldoon/38-39; Staff/600, Pileggi/6.

of 9.2 percent.[11] CUB recommended a capital structure of 50 percent equity and 50 percent long-term debt, and an ROE of 9.24 percent.[12]

As a result of their settlement discussions, the Stipulating Parties agree to a ROR of 7.120 percent, which is based on a 50.0 percent common equity and 50.0 percent long-term debt capital structure, with cost of long-term debt of 4.740 percent and an ROE of 9.50 percent. This Cost of Capital results in a reduction to revenue requirement of $18.171 million.[13]

Table 1 – Cost of Capital Components

Component	Capital Structure	Component Cost	Weighted Cost
Cost of Long-Term Debt	50%	4.740%	2.370%
Return on Common Equity (ROE)	50%	9.5%	4.750%
	Rate of Return		**7.120%**

Q. Please explain why the Stipulating Parties' agreement regarding NW Natural's Cost of Capital is reasonable.

A. A capital structure of 50 percent equity and 50 percent debt maintains the capital structure last approved by the Commission in NW Natural's most recent rate case.[14] A cost of long-term debt of 4.740 percent and an ROE of 9.50 percent are compromises among the Stipulating Parties with respect to their original proposals and the modeling performed by the Stipulating Parties' respective expert witnesses. The Stipulating Parties' compromise falls within the range of

[11] AWEC/100, Mullins/1-2.
[12] CUB/100, Jenks/12.
[13] First Partial Multi-Party Stipulation Regarding Revenue Requirement at 3.
[14] Docket No. UG 490, Order No. 24-359 at 4, 6.

reasonable ROEs recommended by Staff, and although it is higher than the range recommended by AWEC and the ROE recommended by CUB, upon discussion and analysis, all Stipulating Parties agree a ROE of 9.50 percent, for the sake of settlement, and in the context of the First Stipulation as a whole, represents a reasonable settlement of the issues.

B. Cash Working Capital

Q. Please describe the Stipulating Parties' agreement regarding Cash Working Capital.

A. In the Initial Filing, NW Natural presented the results of the lead-lag study the Company performed to derive the cash working capital component of its rate base request in this case.[15] NW Natural stated that its lead-lag study showed that NW Natural's average operating revenue lag is 40.9 days and its average daily cash working capital requirement in Oregon for the Test Year is $29.4 million, which corresponds to a cash working capital factor of 3.8 percent.[16] In Opening Testimony, Staff stated that it had no concerns with how the Company calculated the revenue lag, service lag or expense lag components of its cash working capital calculation, but stated that it had a concern regarding the annual expenses the Company applied its cash working factor to, because the annual expenses the Company used to calculate cash working capital were different from the Test Year expenses in the Company's revenue requirement model.[17] Therefore, Staff recommended accepting the Company's filed cash working capital factor but

[15] NW Natural/1500, Walker/29-37.
[16] NW Natural/1500, Walker/29, 31, 36.
[17] Staff/200, Chipanera-Stevens-Mondragon/16-17.

applying it to the Test Year operating expenses in the Company's filed revenue requirement model, and adjusting those expenses in accordance with Staff's overall proposed reduction in Test Year expenses of $27.692 million set forth in Staff's Opening Testimony.[18] This reduction would have resulted in a reduction of $1.692 million to the Company's requested cash working capital allowance.[19]

CUB did not address the Company's request for cash working capital in its Opening Testimony, and AWEC's proposed adjustment to cash working capital described in its Opening Testimony was resolved as part of the black box settlement discussed below.

In its Reply Testimony, NW Natural responded to Staff's and AWEC's positions regarding cash working capital.[20] NW Natural stated it believed it was appropriate to use operating expenses and prepaid assets from the cash working capital model rather than the operating expenses used for revenue requirement and provided a reconciliation of the differences between the cash working capital model and the revenue requirement model.[21] The Company also corrected a double counting error in its cash working capital calculation and its revenue requirement, and adjusted cash working capital to reflect the adjustments made in operating expenses in NW Natural's Reply Testimony.[22] In total, the Company's adjustments in Reply Testimony reduced cash working capital by $95,658, a revenue requirement reduction of $9,578.[23]

[18] Staff/200, Chipanera-Stevens-Mondragon/18.
[19] Staff/200, Chipanera-Stevens-Mondragon/18.
[20] NW Natural/3200, Walker/5-11.
[21] NW Natural/3200, Walker/6-8.
[22] NW Natural/3200, Walker/8.
[23] NW Natural/3200, Walker/8.

As a result of their settlement discussions, the Stipulating Parties agreed to a revenue requirement reduction associated with Cash Working Capital of $49 thousand.[24]

Q. Please explain why the Stipulating Parties' agreement regarding this aspect of Cash Working Capital is reasonable.

A. The Stipulating Parties' agreement to reduce revenue requirement by $49 thousand represents a middle ground among the Stipulating Parties' different positions. This outcome represents a negotiated resolution that is informed by the Stipulating Parties' settlement discussions and review of testimony and discovery, and therefore is a resolution that is reasonable, fair, and in the public interest.

C. Land Purchase Associated with The Dalles Resource Center

Q. Please describe the Stipulating Parties' agreement regarding the land purchase associated with The Dalles Resource Center.

A. In its Initial Filing, NW Natural explained that it is relocating its resource center in The Dalles to a new location due to inadequacies with the current office building that houses the resource center.[25] This move involves the purchase of a new piece of land in 2025 to build the new facility, which NW Natural estimates to cost approximately $1.3 million.[26] In Staff's Opening Testimony, Staff recommended a disallowance of the entire $1.3 million request, based on concerns that: 1) the real estate summary provided by NW Natural's broker for the search for the new facility's location included a cost of $999,999.00 for the land acquisition, a different

[24] First Partial Multi-Party Stipulation Regarding Revenue Requirement at 3.
[25] NW Natural/600, Pipes/2, 4.
[26] NW Natural/600, Pipes/2, 6, 10.

number than the estimate in the Initial Filing,[27] and 2) that the land purchase did not meet the "used and useful" standard.[28] CUB and AWEC did not address the land purchase for The Dalles Resource Center in their Opening Testimony.

In its Reply Testimony, NW Natural responded to Staff's concerns about NW Natural's cost recovery request for The Dalles Resource Center. NW Natural explained that the land would be used and useful once the land purchase was finalized, because the land would be immediately used for equipment and materials storage, as well as other activities.[29] The Company also explained that the reason for the discrepancy between the $999,999.00 estimated land purchase cost in the broker's report and the $1.3 million provided in the Company's Opening Testimony was that the $1.3 million included costs associated with due diligence for the purchase, including preliminary planning and design work.[30]

As a result of their settlement discussions, the Stipulating Parties agreed to remove the land purchase[31] from this proceeding—which results in a reduction to revenue requirement of $90 thousand.[32]

Q. Please explain why the Stipulating Parties' agreement regarding the land purchase associated with The Dalles Resource Center is reasonable.

A. While the Company and Staff differed regarding the concerns raised in Staff's testimony, for the sake of settlement, and in the context of the First Stipulation as a whole, the Company believes that it is fair and reasonable to reduce revenue

[27] Staff/800, Bolton/15.
[28] Staff/800, Bolton/16-17.
[29] NW Natural/2200, Pipes/2.
[30] NW Natural/2200, Pipes/3.
[31] NW Natural/2200, Pipes/3.
[32] First Partial Multi-Party Stipulation Regarding Revenue Requirement at 3.

requirement by an amount commensurate with the Oregon-allocated portion of the land acquisition for The Dalles Resource Center in this proceeding. The Stipulating Parties agree that this adjustment, in the context of the First Stipulation as a whole, will result in rates that are just and reasonable.

D. Membership and Dues Expense

Q. Please describe the Stipulating Parties' agreement regarding Membership and Dues expense.

A. In its Opening Testimony, Staff recommended an Oregon-allocated Test Year disallowance to memberships and dues of $341,543 and disallowance to donations of $52,435, due to Staff's concern that some of the activities carried out by the organizations to which the Company pays memberships and dues are not necessary for utility service, primarily to promote the Company within the community, not to benefit ratepayers, or not recoverable in rates if done by the utility itself.[33] Specifically, based on Staff's review of NW Natural's responses to Standard Data Request No. 90 and Staff data requests, Staff proposed to remove the full Oregon-allocated Test Year expense for Staff-identified memberships related to economic development and civic organizations, escalated for the Test Year using the All-Urban CPI inflation factors for 2025 and 2026; 25 percent of the escalated expense for Staff-identified memberships in the Test Year related to, but not limited to, national and regional industry trade organizations; and the full amount of the Oregon-allocated escalated expense for Staff-identified donations

[33] Staff/1100, Ball/18-20.

in the Test Year.[34] CUB and AWEC did not address the Company's expense associated with Memberships and Dues in their Opening Testimony.

In its Reply Testimony, the Company responded to Staff's concerns, explaining that donations expense was removed from the Company's requested revenue requirement in this case.[35] The Company also explained why the Company's memberships in trade organizations and economic development and civic organizations benefit customers and therefore are appropriate to include in revenue requirement, and that the Company excludes from recovery the portions of membership fees that are associated with lobbying.[36]

As a result of their settlement discussions, the Stipulating Parties agreed to a reduction to revenue requirement of $350 thousand for Membership and Dues Expense.[37]

Q. Please explain why the Stipulating Parties' agreement regarding Membership and Dues expense is reasonable.

A. Although the Stipulating Parties do not necessarily agree regarding the extent to which NW Natural's customers benefit from the Company's memberships and dues expenses, the Stipulating Parties do agree that a reduction to revenue requirement of $350 thousand—which is nearly equivalent to the full amount of the adjustment recommended by Staff in Opening Testimony—is a reasonable resolution for settlement purposes. The Stipulating Parties believe that this

[34] Staff/1100, Ball/19-20.
[35] NW Natural/2900, Davilla/16-17.
[36] NW Natural/2900, Davilla/14-16.
[37] First Partial Multi-Party Stipulation Regarding Revenue Requirement at 3.

adjustment, in the context of the First Stipulation as a whole, will result in rates that are just and reasonable.

E. Meals and Entertainment Expense

Q. Please describe the Stipulating Parties' agreement regarding Meals and Entertainment expense.

A. In the Initial Filing, the Company included expenses associated with employee meals and entertainment, awards, gifts, airfare, lodging, and travel expenses in the Test Year. In Staff's Opening Testimony, Staff reviewed what Staff characterized as the Company's "[Operations and Maintenance (O&M)] non-payroll transactional expenses" to identify "O&M non-payroll discretionary expenses" such as "meals and entertainment, awards, recognition, gift cards, coffee, and refreshments."[38] Staff recommended excluding 50 percent of transactions that it deemed "discretionary" and of benefit to both shareholders and customers, based on the Commission's adoption of 50/50 cost sharing in docket UE 197.[39] In total, Staff recommended reducing the Company's non-labor O&M expenses by $410,487.[40] CUB and AWEC did not address the Company's meals and entertainment expense in their Opening Testimony.

In its Reply Testimony, the Company responded to Staff, explaining that the General Ledger Account that Staff reviewed to arrive at its meals and entertainment adjustment included some categories of costs that were not discretionary, such as permits, meal tickets, and the 2024 Pipeline and Hazardous

[38] Staff/1100, Ball/21-22.
[39] Staff/1100, Ball/21 (citing *In the Matter of Portland General Electric Company, Request for a General Rate Revision*, Docket No. UE 197, Order No. 09-020 (Jan. 22, 2009)).
[40] Staff/1100, Ball/23.

Materials Safety Administration ("PHMSA") Assessment Fee to the Portland LNG facilities, and therefore the adjustment was overinclusive.[41] The Company also stated that it disagreed with Staff with respect to whether expenses such as employee awards and gifts, or refreshments and meals, should be deemed prudent and fully recoverable expenses.[42] The Company stated that although it disagreed with Staff's adjustments for meals and entertainment, awards, gifts, airfare, lodging, and travel, the Company would narrow the issues in the case by removing its request for amounts in these categories other than the amounts associated with the Company's safety jackpot program, meal tickets, and the 2024 LNG PHMSA fee, which the Company explained were non-discretionary.[43] In total, the Company removed $224,280 in its Reply Testimony.[44]

As a result of their settlement discussions, the Stipulating Parties agreed to a reduction to revenue requirement of $68 thousand for Meals and Entertainment Expense.[45]

Q. Please explain why the Stipulating Parties' agreement regarding Meals and Entertainment is reasonable.

A. Although the Stipulating Parties do not necessarily agree regarding whether expenses in this category should be subject to cost sharing, they agree that their resolution of this issue through an adjustment of $68 thousand is fair and reasonable. The Stipulating Parties' adjustment takes account of the Company's

[41] NW Natural/2900, Davilla/23-26.
[42] NW Natural/2900, Davilla/24-27.
[43] NW Natural/2900, Davilla/27-28.
[44] NW Natural/2900, Davilla/27-28.
[45] First Partial Multi-Party Stipulation Regarding Revenue Requirement at 4.

previous narrowing of its cost recovery request for meals and entertainment expenses in its Reply Testimony as well as the Stipulating Parties' interest in reaching a negotiated resolution. The Stipulating Parties believe that, in the context of the First Stipulation as a whole, this adjustment will result in rates that are just and reasonable.

F. D&O Insurance Expense

Q. Please describe the Stipulating Parties' agreement regarding D&O Insurance expense.

A. NW Natural included directors and officers ("D&O") insurance premiums in the Test Year.[46] In Staff's Opening Testimony, Staff recommended permitting the Company to recover a projected amount for its 2025-2026 D&O insurance policy renewal by escalating the Company's 2024-2025 Oregon-allocated D&O insurance premium by 1.3 percent and then disallowing 50 percent of the resulting amount, which Staff asserts is standard Commission policy.[47] Staff's method would result in a downward adjustment of $729,015 to the Company's D&O Insurance expense.[48] AWEC also recommended 50/50 cost sharing between shareholders and ratepayers for NW Natural's D&O insurance costs based on AWEC's understanding of Commission policy.[49] AWEC calculated a $51,539 reduction to revenue requirement as a result of its adjustment.[50] CUB did not address D&O premiums in its Opening Testimony.

[46] *See* NW Natural/1300, Davilla/13-14.
[47] Staff/1100, Ball/13-14.
[48] Staff/1100, Ball/13.
[49] AWEC/100, Mullins/40.
[50] AWEC/100, Mullins/40.

In its Reply Testimony, the Company responded both to Staff and AWEC's 50 percent sharing proposal as well as Staff's use of a 1.3 percent escalation to arrive at a D&O insurance premium amount.[51] The Company explained that it disagreed with the premise that customers receive only a partial benefit from the Company's D&O insurance expense, because D&O insurance is a necessary cost of doing business and a prudent expense.[52] The Company also explained that, because the Company already removed D&O liability expenses allocated to non-utility business units, the remaining amounts should be fully recovered.[53] The Company also provided an update concerning updated estimates it had received from its D&O insurance broker for the Company's D&O premiums for its 2025-2026 renewal.[54] Based on the updated estimates the Company received from its broker, NW Natural reduced its request for D&O insurance costs from the amount in the Initial Filing.[55]

As a result of their settlement discussions, the Stipulating Parties agreed to a reduction to revenue requirement of $312 thousand for D&O Insurance expense.[56]

Q. Please explain why the Stipulating Parties' agreement regarding D&O Insurance is reasonable.

A. The Stipulating Parties' agreed reduction to D&O insurance expense is a reasonable compromise between Staff's and AWEC's position and the Company's

[51] NW Natural/2900, Davilla/58-61.
[52] NW Natural/2900, Davilla/61.
[53] NW Natural/2900, Davilla/61.
[54] NW Natural/1900, Wilson/28-29.
[55] NW Natural/1900, Wilson/29.
[56] First Partial Multi-Party Stipulation Regarding Revenue Requirement at 4.

position. Although the Stipulating Parties do not necessarily agree with respect to whether D&O insurance premiums should be subject to cost sharing, they do agree that their agreed reduction to revenue requirement is a reasonable and fair compromise that results in just and reasonable rates.

G. Wages and Salaries, FTE Adjustments, Incentives, Payroll Taxes, Depreciation Expense

Q. Please describe the Stipulating Parties' agreement regarding Wages and Salaries, FTE Adjustments, Incentives, Payroll Taxes, and Depreciation Expense.

A. NW Natural projected having 1,249.1 gas utility Full-Time Employees ("FTEs") in the Test Year[57] and included $132.902 million for wages and salaries associated with Oregon-allocated FTEs[58] and $9.653 million for pay-at-risk[59] in the Test Year. To mitigate the size of its rate request, the Company did not seek recovery of the costs of pay-at-risk for Company officers in this proceeding.[60] Staff recommended a reduction to rate base of $3.725 million associated with the capital components of Staff's adjustments to wages and salaries, FTEs, and incentives, and a reduction to O&M of approximately $6.062 million associated with the non-rate base components of wages and salaries, FTE, and incentives, in addition to corresponding adjustments to payroll tax expense and depreciation expense.[61] AWEC recommended removing 75 percent of employee incentives from the Company's O&M expenses and removal of the capital portion of employee

[57] NW Natural/1000, Rogers/20-21.
[58] NW Natural/1000, Rogers/6.
[59] NW Natural/1000, Rogers/12.
[60] NW Natural/1000, Rogers/8.
[61] Staff/1200, Dyck/3-23.

incentives from rate base, resulting in a reduction to revenue requirement of approximately $4.627 million.[62] CUB did not address wages and salaries, FTE adjustments, incentives, payroll taxes, and depreciation expense in its Opening Testimony. The Company filed Reply Testimony responding to Staff and AWEC's Opening Testimony regarding employee and officer compensation.[63]

As a result of their settlement discussions, the Stipulating Parties agreed to a reduction to rate base of $2.971 million, resulting in a reduction to revenue requirement of $270 thousand. The Stipulating Parties also agreed to a reduction to O&M expense equivalent to a $4.698 million reduction to revenue requirement. Combined, these adjustments result in a total reduction to revenue requirement of $4.968 million.[64]

Q. Please explain why the Stipulating Parties' agreement regarding Wages and Salaries, FTE Adjustments, Incentives, Payroll Taxes, and Depreciation Expense is reasonable.

A. The Stipulating Parties' agreement to reduce revenue requirement by $4.968 million in total—based on a reduction to rate base of $2.971 million and a reduction to expense of $4.698 million—is a reasonable compromise of the Stipulating Parties' differing interpretations of Commission precedent and different analytical approaches to calculating projected FTEs, as well as costs and expenses for wages, salaries, and incentives. The Stipulating Parties' agreement is a middle ground among the Stipulating Parties' different viewpoints and corresponding

[62] AWEC/100, Mullins/33.
[63] *See* NW Natural/2500, Rogers.
[64] First Partial Multi-Party Stipulation Regarding Revenue Requirement at 4.

adjustments that they proposed in their filed testimony. As the agreement represents a reasonable negotiated outcome, the Stipulating Parties believe the adjustment results in just and reasonable rates in the context of the First Stipulation overall.

H. Advertising Expense

Q. Please describe the Stipulating Parties' agreement regarding Advertising Expense.

In the Initial Filing, NW Natural requested $1.521 million for Category A (customer communications) advertising expense for the Test Year, which was approximately $160 thousand, or $0.22 per customer, in excess of the level presumed just and reasonable under OAR 860-026-0022(3)(a).[65] The Company explained that it believed the portion of its Category A expense request above the amount presumed just and reasonable under OAR 860-026-0022(3)(a) should be recoverable, because this amount was on par with the amounts presumed reasonable for electric utilities in NW Natural's service territory based on the revenue-based formula, due to differences in revenue structure between gas and electric utilities.[66] The Company also explained that it had requested Category A expense above the amount presumed reasonable under OAR 860-026-0022(3)(a) because of additional targeted communications and outreach for the Company's bill discount program.[67] The Company also requested $900 thousand for Category B advertising expense in the Test Year.[68] NW Natural did not seek recovery of any

[65] NW Natural/1100, Beck/1-3; NW Natural/2600, Beck/2.
[66] NW Natural/1100, Beck/3-4
[67] NW Natural/1100, Beck/6-8.
[68] NW Natural/1100, Beck/13.

expenses in Category C (corporate imaging), Category D (political/non-utility advertising), or Category E (energy efficiency/consideration advertising related to a program approved by the Commission).[69]

In Staff's Opening Testimony, Staff recommended a reduction to Category A expense of $159,697, or the amount beyond the level presumed reasonable under OAR 860-026-0022(3)(a).[70] Staff stated it "appreciates the Company's point that the difference in revenue structure between natural gas and electric utilities results in a disparity on a per customer basis with regard to advertising expense," but explained that Staff does not view this disparity as a sufficient grounds for finding the Company's Category A advertising expense above the amount presumed reasonable to be recoverable.[71] AWEC and CUB did not address advertising expense in their Opening Testimony.

In its Reply Testimony, the Company responded to Staff's Opening Testimony regarding advertising expense and made a correction to the allocation of Category A and Category B expense. By moving the cost of legally mandated customer notices from Category A to B, NW Natural revised its request for Category A to $1.485 million, or $2.10 per customer, and revised its request for Category B to $936 thousand.[72]

As a result of their settlement discussions, the Stipulating Parties agreed to a reduction to revenue requirement of $123 thousand for Advertising Expense.[73]

[69] NW Natural/1100, Beck/2.
[70] Staff/1400, Moore/5.
[71] Staff/1400, Moore/4-5.
[72] NW Natural/2600, Beck/22.
[73] First Partial Multi-Party Stipulation Regarding Revenue Requirement at 4.

Q. Please explain why the Stipulating Parties' agreement regarding Advertising Expense is reasonable.

A. The Stipulating Parties continue to have different views regarding whether the disparity between gas and electric utilities under the revenue-based approach to advertising expense in OAR 860-026-0022(3)(a) is informative with respect to whether Category A spending amounts are just and reasonable. However, the Stipulating Parties agree that their adjustment, which would remove from revenue requirement the amount of NW Natural's revised Category A request above the amount presumed reasonable, is a fair compromise between the Stipulating Parties' different positions for settlement purposes. The Stipulating Parties believe that this adjustment results in rates that are just and reasonable in the context of the First Settlement as a whole.

I. Leasehold Improvements

Q. Please describe the Stipulating Parties' agreement regarding Leasehold Improvements.

A. NW Natural's Initial Filing requested to include $17.317 million in Oregon-allocated Test Year rate base for leasehold improvements, primarily associated with the Company's headquarters at 250 Taylor.[74] This represented a $1.279 million decrease to the amount approved for leasehold improvements in the Company's last rate case.[75] Staff stated in its Opening Testimony that it had reviewed testimony, orders, and workpapers regarding this issue; issued DRs; and was "awaiting responses to DRs and may have an adjustment once the analysis is

[74] NW Natural/1500, Walker/27; NW Natural/1501, Walker/1.
[75] NW Natural/1502, Walker/1.

complete."[76] AWEC stated that it disagreed with the Company's methodologies for calculating non-plant balances, including leasehold improvements, but did not recommend a specific adjustment to leasehold balances.[77] CUB did not address leasehold improvements in its Opening Testimony.

As a result of their settlement discussions, the Stipulating Parties agreed to a reduction to rate base of $49 thousand for leasehold improvements, which results in a reduction to revenue requirement of $4 thousand.[78]

Q. Please explain why the Stipulating Parties' agreement regarding Leasehold Improvements is reasonable.

A. The Stipulating Parties' modest reduction to rate base to reach an agreed resolution to the leasehold improvements issue is reasonable, considering that none of the Stipulating Parties proposed a specific adjustment for leasehold improvements in Opening Testimony. In the context of the First Stipulation as a whole, the Stipulating Parties believe their adjustment is a fair and reasonable resolution that will result in rates that are just and reasonable.

J. Retirement of GC 500 Mist Compressor

Q. Did the Stipulating Parties agree to a revenue requirement adjustment related to the retirement of the GC 500 Mist Compressor?

A. Yes. As a result of their settlement discussions, the Stipulating Parties agreed to a cost recovery arrangement associated with the retirement of the GC 500 compressor, which is described in greater detail in Section III.O below. The

[76] Staff/200, Chipanera-Stevens-Mondragon/24.
[77] AWEC/100, Mullins/29.
[78] First Partial Multi-Party Stipulation Regarding Revenue Requirement at 4.

Stipulating Parties' agreement results in a reduction to revenue requirement of $1.378 million.[79] As addressed further in Section III.O below, the Stipulating Parties believe this adjustment is reasonable.

K. Test Year Plant Additions and Other Miscellaneous Adjustments

Q. Please describe the Stipulating Parties' agreement regarding Test Year Plant Additions and Other Miscellaneous Adjustments.

A. The Company calculated Utility Plant in Service during the Test Year by using a 13-month Average-of-Monthly-Averages (AMA) approach and including all capital additions in the forward test year, including those associated with customer additions (mains, services, and meters), as well as recurring replacement of capital assets, and larger planned projects through the Test Year.[80] The Company also proposed to roll forward accumulated depreciation through the Test Year, and lowered its gross plant and accumulated depreciation amounts for the Test Year to reflect forecasted asset retirements.[81]

In Opening Testimony, Staff disagreed with including all Test Year capital additions in rate base, based on Staff's interpretation of ORS 757.355(1).[82] Staff proposed excluding all Test Year capital additions from rate base except for growth-related capital additions on the basis that including growth-related capital additions was responsive to the Commission's orders regarding rate base calculation method in Docket Nos. UE 433 and UE 435, Staff's view that growth-related capital investment is predictable, and because of the system benefit of new revenues from

[79] First Partial Multi-Party Stipulation Regarding Revenue Requirement at 4-5.
[80] NW Natural/1500, Walker/25.
[81] NW Natural/1500, Walker/25.
[82] Staff/200, Chipanera-Stevens-Mondragon/8.

new customers causing the growth-related capital additions.[83] As a result of Staff's adjustment, Staff recommended a reduction to revenue requirement of approximately $10.1 million at the Company's requested cost of capital, or between $9.2 million and $9.6 million at Staff's proposed cost of capital range.[84]

In its Opening Testimony, AWEC recommended that plant additions and retirements occurring subsequent to the rate effective date not be considered in NW Natural's revenue requirement, based on AWEC's interpretation of ORS 757.355.[85] The impact of AWEC's proposal would be to reduce revenue requirement by $13.099 million.[86] In addition to the treatment of rate base, AWEC raised several other revenue requirement issues, which were resolved through the black box adjustment, including adjustments to cash working capital, directors' and officers' fees and expenses, stock incentives, miscellaneous operations and maintenance expenses and other adjustments.

In its Reply Testimony, NW Natural responded to Staff's and AWEC's testimony regarding rate base methodology, including by explaining why the Company believed that the guardrails in its rate base methodology, such as the moderating effect of a large capital investment portfolio and the AMA approach, addressed Staff's and AWEC's concerns about consistency with ORS 757.355.[87]

As a result of their settlement discussions, the Stipulating Parties agreed to a black box reduction to revenue requirement of $7.2 million, which

[83] Staff/200, Chipanera-Stevens-Mondragon/8-10.
[84] Staff/200, Chipanera-Stevens-Mondragon/10.
[85] AWEC/100, Mullins/24.
[86] AWEC/100, Mullins/24.
[87] NW Natural/3100, Dane/3-35.

comprehensively addressed Test Year Plant Additions and other miscellaneous issues and adjustments raised in the proceeding.[88]

Q. Please explain why the Stipulating Parties' agreement regarding Test Year Plant Additions and Other Miscellaneous Adjustments is reasonable.

A. Although the Stipulating Parties do not agree with respect to rate base calculation method, the Stipulating Parties do agree that a black box adjustment of $7.2 million to resolve their differences of opinion concerning rate base, as well as other miscellaneous adjustments, is reasonable. This adjustment was the subject of active negotiation by the Stipulating Parties and results from concessions on the part of each Stipulating Party. Moreover, the Stipulating Parties agree that, in the context of the First Stipulation as a whole, this adjustment will result in rates that are just and reasonable.

L. Officer Attestations

Q. Please explain the Stipulating Parties' agreement regarding attestations for capital projects.

A. In its Opening Testimony, AWEC recommended a capital attestation process similar to the one adopted by the Commission in Docket No. UE 435.[89] AWEC recommended that NW Natural provide capital attestations for all projects over $1 million, with projects under $1 million reviewed in the aggregate as a single project, on a portfolio basis.[90] In its Reply Testimony, the Company proposed to file two attestations confirming that projects over $1 million would be placed in service

[88] First Partial Multi-Party Stipulation Regarding Revenue Requirement at 4.
[89] AWEC/100, Mullins/26-27.
[90] AWEC/100, Mullins/27.

by October 31, 2025.[91] Staff proposed that NW Natural provide officer attestations for all new "discrete" projects requested in the Initial Filing that are expected to go in service by October 31, 2025.[92] The Company proposed that projects over $1 million that would not be completed by the rate effective date would be incorporated into an updated future test year (FTY) forecast with a revised in-service date and recovered in the FTY using the Average of Monthly Averages (AMA) methodology.[93]

As a result of their settlement discussions, the Stipulating Parties agree that NW Natural will file officer attestations on or before October 3, 2025, and October 23, 2025, attesting to whether any projects forecast to cost over $1 million and to be completed by October 30, 2025, will be completed after that date. The Stipulating Parties further provided that if there are any such projects, those projects will be removed from rates.[94]

Q. Please explain why the Stipulating Parties' agreement regarding attestations is reasonable.

A. The Stipulating Parties agree that NW Natural providing officer attestations for certain capital projects will facilitate final review of project costs and ensure that only projects completed by the October 30, 2025, cut-off date will be included in rates. The Stipulating Parties agree that this approach reflects a reasonable compromise between the Stipulating Parties' positions.

[91] NW Natural/1700, Rush-Kravitz/14.
[92] Staff/1000, Abraham/7; Staff/200, Chipanera-Stevens-Mondragon/11 (providing Staff's definition of "discrete" projects).
[93] NW Natural/1700, Rush-Kravitz/14.
[94] First Partial Multi-Party Stipulation Regarding Revenue Requirement at 4-5.

M. Rate Effective Date

Q. Please describe the Stipulating Parties' agreement regarding the rate effective date.

A. In the Initial Filing, NW Natural requested that the new rates resulting from this proceeding be made effective November 1, 2025.[95] As part of the First Stipulation, the Stipulating Parties agree to move the rate effective date to October 31, 2025—an advancement of the rate effective date by one day.[96] The Stipulating Parties understand that their agreement to modify the rate effective date to October 31, 2025, is subject to the Commission's approval.

Q. Please explain why the Stipulating Parties believe a change in the rate effective date is reasonable.

A. Modifying the rate effective date by one single day is reasonable, given the pendency of legislation that may prohibit NW Natural from implementing its requested rate increase on November 1, 2025. Because this minor modification of the rate effective date would have no legal or practical effect on the sufficiency of the time for Commission review and public notice of the Company's rate revision requested in this proceeding, and for the sake of efficiency, the Stipulating Parties agree that modification of the rate effective date from November 1, 2025, to October 31, 2025, is fair, just, and reasonable.

N. Depreciation Rates

Q. Please describe the Stipulating Parties' agreement regarding Depreciation Rates.

[95] Executive Summary at 1.
[96] First Partial Multi-Party Stipulation Regarding Revenue Requirement at 5.

A. In the Initial Filing, the Company stated that it was proposing updated depreciation rates as part of this general rate case, based on the updated depreciation study filed concurrently with this proceeding in Docket No. UM 2363 on December 30, 2024.[97] On June 13, 2025, NW Natural, Staff, and AWEC filed a notice in Docket No. UM 2363, informing the Commission that they had reached a comprehensive agreement in principle.[98]

The Stipulating Parties agree to adjust the Company's depreciation rates subject to the resolution of the Company's depreciation study in Docket No. UM 2363. Although the Company's updated depreciation rates have not yet been resolved in Docket No. UM 2363, the Company expects the reduction to revenue requirement associated with this adjustment to be $5.278 million.[99]

Q. Please explain why the Stipulating Parties' agreement regarding Depreciation Rates is reasonable.

A. The Stipulating Parties' agreement that the Company will update depreciation rates for purposes of the rates resulting from this proceeding based on the outcome of Docket No. UM 2363 is reasonable. Doing so will ensure that the Company's depreciation expense reflected in the revenue requirement approved in this proceeding will be the product of the most accurate, current information about the depreciable lives of the Company's assets.

[97] Executive Summary at 7.
[98] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Updated Depreciation Study*, Docket No. UM 2363, Status Update (June 13, 2025).
[99] First Partial Multi-Party Stipulation Regarding Revenue Requirement at 5.

O. Retirement of GC 500 Mist Compressor – Regulatory Asset

Q. Please describe the Stipulating Parties' agreement regarding the GC 500 Mist Compressor.

A. In the Initial Filing, the Company indicated that it is replacing the older of the two compressors at its Mist storage facility, the GC 500 compressor, in October 2025, and a second compressor at the Mist facility, the GC 600, is scheduled for replacement in October 2026.[100] The Company stated that it is replacing these two compressors because they have exceeded their expected useful lives and require ongoing break-fix repairs that routinely disrupt operations at the Mist facility.[101]

In its Opening Testimony, Staff stated it agreed with the Company's assessment that both Mist compressors had exceeded their useful life expectancy, but Staff would not support the inclusion in rates of new plant not yet in service by the rate effective date.[102] Therefore, Staff stated it would "monitor the progress" of the GC 500 project and require officer attestations supporting the Company's projection that the project is on track to be completed by October 31, 2025.[103]

In its Opening Testimony, CUB stated it did not oppose the retirement and replacement of the GC 500 compressor, and CUB recommended that the Commission find the GC 500 retirement to be in the public interest.[104] CUB estimated that the Company's undepreciated investment in the GC 500 compressor was $14.754 million, based on CUB's assumption that the GC 500

[100] Executive Summary at 4; NW Natural/100, Palfreyman-Kravitz/14.
[101] NW Natural/100, Palfreyman-Kravitz/14.
[102] Staff/1000, Abraham/9-11.
[103] Staff/1000, Abraham/10.
[104] CUB/100, Jenks/19.

compressor had a 27-year useful life and a 50-year depreciable life.[105] CUB recommended that the Company be allowed to recover, but not earn a return on, its undepreciated investment in the GC 500 compressor, and that $14.8 million be removed from FERC Account 354 and placed in a regulatory asset, where it would be amortized over 23 years at 4.499 percent, representing the time value of money.[106] CUB stated that its recommended cost recovery treatment for the undepreciated portion of the GC 500 compressor was based on CUB's understanding of the Commission's retired asset policy.

NW Natural filed Reply Testimony responding to CUB's proposal. NW Natural defended the continued inclusion of the GC 500 unit in FERC Account 354, argued that there was not a need for extraordinary ratemaking treatment for the GC 500 plant following its retirement, and disagreed with CUB's interpretation of the Commission's retired asset policy.[107] NW Natural also clarified that the undepreciated portion of the GC 500 compressor upon its retirement would be approximately $11.1 million, rather than CUB's estimate of $14.8 million, and that the actual amount of undepreciated investment in the GC 500 compressor at the time of its retirement would actually be somewhat less than $11.1 million, accounting for the actual net book value at that time, as well as the cost of removal and salvage value.[108]

As a result of their settlement discussions, the Stipulating Parties agreed that NW Natural will remove $11.1 million, representing the net book value of the

[105] CUB/100, Jenks/18-19.
[106] CUB/100, Jenks/19-20.
[107] NW Natural/3000, Spanos-Wilson-Kravitz/16-20.
[108] NW Natural/3000, Spanos-Wilson-Kravitz/20-21.

GC 500 Mist Compressor, from FERC Account 354, resulting in a reduction to revenue requirement of $1.378 million.[109] The Stipulating Parties further agreed that the $11.1 million will be placed in a regulatory asset and recovered over a period of eight years through a separate base tariff schedule to be filed with the Company's compliance filing in this rate case. The Stipulating Parties agree to use a 4.499 percent interest rate for the regulatory asset. The amortization of the regulatory asset is $1.683 million per year through the separate rate schedule.[110]

Q. Please explain why the Stipulating Parties' agreement regarding the GC 500 Mist Compressor is reasonable.

A. The Stipulating Parties' agreement is a reasonable resolution of CUB's and NW Natural's differing interpretations of Commission orders and policy governing cost recovery for retired assets. The removal of $11.1 million from rate base is responsive to CUB's concern about the Company's ability to earn a return on retired plant, and the eight-year time period for the amortization of the regulatory asset will enable the Company to recover its costs for the GC 500 compressor within a reasonable amount of time. Therefore, the Stipulating Parties believe that the $1.378 million reduction to revenue requirement resulting from the removal of the GC 500 compressor from rate base will result in rates that are just and reasonable, and that the creation and amortization of a regulatory asset as described in the First Stipulation is in the public interest.

[109] First Partial Multi-Party Stipulation Regarding Revenue Requirement at 4-5.
[110] First Partial Multi-Party Stipulation Regarding Revenue Requirement at 5.

IV. SUPPORT FOR THE FIRST STIPULATION

Q. What is the basis for the First Stipulation?

A. The First Stipulation is a compromise based on the record in this case, which includes NW Natural's Initial Filing, the Opening Testimony of Staff and intervenors, and NW Natural's Reply Testimony, as well as the data requests and data responses the parties have exchanged to date. Over the course of the settlement discussions, the Stipulating Parties resolved their differences regarding all issues in the First Stipulation—except for those explicitly excluded in Paragraph 3 of the First Stipulation—and ultimately resolved all issues in the First Stipulation through dialogue, negotiations, and compromise to reach a fair result.

Q. What is your recommendation to the Commission regarding the First Stipulation?

A. The Stipulating Parties recommend and request that the Commission approve the First Stipulation in its entirety.

Q. Please explain why the Stipulating Parties believe the Commission should adopt the First Stipulation.

A. The Stipulating Parties have carefully reviewed NW Natural's Initial Filing, NW Natural's responses to data requests, and have thoroughly analyzed the issues during multiple days of settlement conferences. The Stipulating Parties believe that the adjustments and agreements in the First Stipulation provide a fair and reasonable resolution of the issues in this proceeding and the resulting rates are fair, just, and reasonable.

V. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

NW Natural®

Rates & Regulatory Affairs
UG 527
NW Natural Alternative Rate Mechanism
Data Request Response

Request No.: UG 527 CUB DR 15

It is CUB's understanding that these Mist storage facility investments are being retired:

a. GC600 turbine compressor;
b. Main Feed Replacement Project;
c. Mist Well Separator Replacement Project.

For each of these assets/projects, please provide the following information:

a. What is the depreciable life of each of those investments?
b. What is each asset's depreciation rate?
c. Are the depreciated as separate assets or in group depreciation?
d. When were each of these assets installed?

Response:

GC600 Turbine Compressor

a. The current depreciable life for the Group as of OR rates effective November 2025 is 50 years.
b. The current depreciation rate effective November 2025 is an annual rate of 1.99%
c. These assets are depreciated using group depreciation.
d. This specific asset was put into service in 2003.

Main Feed Replacement Project

a. The current depreciable life for the Group as of OR rates effective November 2025 is 50 years.
b. The current depreciation rate effective November 2025 is an annual rate of 1.99%
c. These assets are depreciated using group depreciation.
d. This asset was put into service in 1991.

Mist Well Separator Replacement Project

a. The current depreciable life for the Group as of OR rates effective November 2025 is 52 years.
b. The current depreciation rate effective November 2025 is an annual rate of 1.93%
c. These assets are depreciated using group depreciation.
d. This asset was put into service in 1987 and 2007.

Group depreciation rates represent the overall estimated useful life for the entire group, expecting lives to be shorter and longer, and that there can be other operating purposes (repairs, higher usage, etc) that can impact the underlying useful life of individual assets within the group.

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Rates & Regulatory Affairs
UG 527
NW Natural Alternative Rate Mechanism
Data Request Response

Request No.: UG 527 CUB DR 16

What's the total amount of rate base of Mist assets in group depreciation as of November 1, 2025, for each of the last 5 years?

Response:

Please see UG 527 CUB DR 16 Attachment 1 for the total amount of rate base of Mist assets in Group Depreciation. Our plant reporting processes report on 12/31 annually so we have provided the 5 year summary as of 12/31 (year end) as a proxy for the request for November balances.

Natural Gas Underground Storage			2021 Plant NBV Balance	2022 Plant NBV Balance	2023 Plant NBV Balance	2024 Plant NBV Balance	2025 Plant NBV Balance
	350.1	LAND	106,549	106,549	106,549	106,549	106,549
	350.2	RIGHTS-OF-WAY	74,486	72,922	71,376	69,830	68,285
	351	STRUCTURES AND IMPROVEMENTS	5,604,019	5,699,985	10,956,446	13,590,635	13,878,974
	352	WELLS	18,046,720	21,756,038	26,681,304	36,199,413	36,185,301
	352.1	STORAGE LEASEHOLD & RIGHTS	1,995,793	1,932,975	1,884,925	1,834,597	1,772,587
	352.2	RESERVOIRS	4,221,368	4,098,947	3,993,495	4,586,911	4,451,115
	352.3	NON-RECOVERABLE NATURAL GAS	2,578,878	2,479,045	2,385,652	2,293,978	2,209,585
	353	LINES	4,407,194	5,564,601	6,185,337	6,080,833	6,045,124
	354	COMPRESSOR STATION EQUIPMENT	10,992,617	13,111,251	21,873,080	23,628,200	88,254,923
	355	MEASURING / REGULATING EQUIPM	11,670,758	22,371,295	23,986,455	26,821,635	29,447,545
	356	PURIFICATION EQUIPMENT	27,746,500	27,653,319	27,131,702	26,743,334	26,302,544
	357	OTHER EQUIPMENT	3,946,123	3,944,655	3,814,172	3,701,063	3,594,675
		Natural Gas Underground Storage Subtotal	91,391,005	108,791,581	129,070,493	145,656,979	212,317,206

Natural Gas Underground Storage			2021 Plant NBV Balance	2022 Plant NBV Balance	2023 Plant NBV Balance	2024 Plant NBV Balance	2025 Plant NBV Balance
	350.1	LAND	106,549	106,549	106,549	106,549	106,549
	350.2	RIGHTS-OF-WAY	74,486	72,922	71,376	69,830	68,285
	351	STRUCTURES AND IMPROVEMENTS	5,604,019	5,699,985	10,956,446	13,590,635	13,878,974
	352	WELLS	18,046,720	21,756,038	26,681,304	36,199,413	36,185,301
	352.1	STORAGE LEASEHOLD & RIGHTS	1,995,793	1,932,975	1,884,925	1,834,597	1,772,587
	352.2	RESERVOIRS	4,221,368	4,098,947	3,993,495	4,586,911	4,451,115
	352.3	NON-RECOVERABLE NATURAL GAS	2,578,878	2,479,045	2,385,652	2,293,978	2,209,585
	353	LINES	4,407,194	5,564,601	6,185,337	6,080,833	6,045,124
	354	COMPRESSOR STATION EQUIPMENT	10,992,617	13,111,251	21,873,080	23,628,200	88,254,923
	355	MEASURING / REGULATING EQUIPM	11,670,758	22,371,295	23,986,455	26,821,635	29,447,545
	356	PURIFICATION EQUIPMENT	27,746,500	27,653,319	27,131,702	26,743,334	26,302,544
	357	OTHER EQUIPMENT	3,946,123	3,944,655	3,814,172	3,701,063	3,594,675
		Natural Gas Underground Storage Subtotal	91,391,005	108,791,581	129,070,493	145,656,979	212,317,206
						Monthly depreciation	353,862.01
						est Balance 10/31/25	213,024,930.26
						annual depreciation (1.99%)	4,239,196.11
						projected ratebase 10/26	208,785,734.15
						ROR	301,830.76
						taxes	60,408.54
						pretax return	362,239.31
						annual drpeacition 10/25	4,239,196.11
						annual depreciation 10/26 (not including new rate base)	4,154,836.11
						difference	84,360.00
						total adjustment	446,599.31

UG 520/CUB/103
Jenks/1

NW Natural®

Rates & Regulatory Affairs
UG 520
NW Natural Request for a General Rate Revision
Data Request Response

Request No.: UG 520 OPUC DR 402

What will be the net plant balance at the end of 2024?

Response:

We are assuming this is asking for the net plant balance for FERC account 354 where the asset costs of the Mist gas compressors are held. The net plant balance of FERC account 354 at the end of 2024 is $23,685,406, or $21,070,537 on an Oregon allocated basis.

NORTHWEST NATURAL GAS COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF DECEMBER 31, 2023

DEPRECIABLE GROUP	PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2023	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
DEPRECIABLE GAS PLANT									
INTANGIBLE PLANT									
303.10 MISCELLANEOUS INTANGIBLE PLANT - SOFTWARE		15-SQ	0	128,050,933.02	26,336,695	101,714,238	9,791,008	7.65	10.4
303.11 MISCELLANEOUS INTANGIBLE PLANT - HORIZON		10-SQ	0	46,726,994.21	4,141,642	42,585,352	5,010,041	10.72	8.5
303.12 MISCELLANEOUS INTANGIBLE PLANT - SECURITY DIRECTIVE		10-SQ	0	22,242,163.51	1,789,927	20,452,237	2,403,337	10.81	8.5
303.20 MISCELLANEOUS INTANGIBLE PLANT - CUSTOMER INFORMATION SYSTEM		15-SQ	0	32,409,597.11	32,398,798	10,799	1,963	0.01	5.5
303.30 MISCELLANEOUS INTANGIBLE PLANT - INDUSTRIAL AND COMMERCIAL		10-SQ	0	4,146,951.00	4,146,951	0	0	-	-
303.70 MISCELLANEOUS INTANGIBLE PLANT - CRMS		5-SQ	0	33,207,967.40	11,320,431	21,887,536	5,597,274	16.86	3.9
303.71 MISCELLANEOUS INTANGIBLE PLANT - CLOUD-BASED SOFTWARE HORIZON		10-SQ	0	24,096,593.68	3,203,067	20,893,527	2,458,062	10.20	8.5
303.72 MISCELLANEOUS INTANGIBLE PLANT - CLOUD-BASED SOFTWARE TSA SECURITY DIRECTIVE		5-SQ	0	3,157,883.11	0	3,157,883	900,792	28.53	3.5
TOTAL INTANGIBLE PLANT				**294,039,083.04**	**83,337,511**	**210,701,572**	**26,162,477**	**8.90**	
OIL GAS FACILITIES									
305.50 STRUCTURES AND IMPROVEMENTS - OTHER		40-S1	(5)	13,156.00	13,814	0	0	-	-
311.70 LIQUEFIED PETROLEUM GAS EQUIPMENT		18-L0.5	(5)	4,033.00	8,066	(3,831)	0	-	-
311.80 LIQUEFIED PETROLEUM GAS EQUIPMENT		18-L0.5	(5)	4,209.00	6,585	(2,166)	0	-	-
TOTAL OIL GAS FACILITIES				**21,398.00**	**28,465**	**(5,997)**	**0**	**-**	
OTHER PRODUCTION FACILITIES									
305.11 STRUCTURES AND IMPROVEMENTS - GAS PRODUCTION		40-S1	(5)	8,320.00	8,736	0	0	-	-
305.17 STRUCTURES AND IMPROVEMENTS - MIXING STATION		40-S1	(5)	46,587.00	51,246	(2,330)	0	-	-
318.30 LIGHT OIL REFINING		45-S2.5	(5)	144,896.00	152,141	0	0	-	-
318.50 TAR PROCESSING		45-S2.5	(5)	243,551.00	255,729	0	0	-	-
319.00 GAS MIXING EQUIPMENT		30-R0.5	(5)	185,448.00	194,720	0	0	-	-
TOTAL OTHER PRODUCTION FACILITIES				**628,802.00**	**662,572**	**(2,330)**	**0**	**-**	
UNDERGROUND STORAGE PLANT									
350.20 LAND RIGHTS		70-R4	0	109,624.94	38,249	71,376	1,545	1.41	46.2
351.00 STRUCTURES AND IMPROVEMENTS		60-R4	0	14,554,925.77	3,598,479	10,956,447	232,069	1.59	47.2
352.00 WELLS		50-S4	0	63,027,620.00	20,130,011	42,897,609	1,219,313	1.93	35.2
352.10 STORAGE LEASEHOLDS AND RIGHTS		55-S3	0	3,939,511.52	2,053,886	1,885,626	65,283	1.66	28.9
352.20 RESERVOIRS		55-S3	0	10,834,054.54	4,520,124	6,313,931	191,859	1.77	32.9
352.30 NONRECOVERABLE GAS		55-R4	0	6,440,889.82	4,055,238	2,385,652	97,235	1.51	24.5
353.00 LINES		55-S3	(15)	12,955,423.07	4,880,336	10,018,401	267,129	2.06	37.5
354.10 COMPRESSOR STATION EQUIPMENT - TURBINE 1		50-R3	(10)	7,885,231.22	3,244,668	5,429,086	150,255	1.91	36.1
354.20 COMPRESSOR STATION EQUIPMENT - TURBINE 2		50-R3	(10)	4,154,699.00	3,255,359	1,314,810	67,461	1.62	19.5
354.30 COMPRESSOR STATION EQUIPMENT - TURBINE 3		50-R3	(10)	21,084,256.03	8,324,605	14,868,077	420,517	1.99	35.4
354.40 COMPRESSOR STATION EQUIPMENT - TURBINE 4		50-R3	(10)	16,396,554.18	7,211,285	10,824,925	325,593	1.99	33.2
354.50 COMPRESSOR STATION EQUIPMENT - TURBINE 5		50-R3	(10)	3,739,476.97	1,231,783	2,881,642	76,801	2.05	37.5
354.60 COMPRESSOR STATION EQUIPMENT - TURBINE 6		50-R3	(10)	260,041.78	55,162	230,884	5,531	2.13	41.7
355.00 MEASURING AND REGULATING EQUIPMENT		45-S2	(10)	39,474,567.00	9,593,627	33,828,397	944,101	2.39	35.8
356.00 PURIFICATION EQUIPMENT		45-S2.5	(5)	28,968,864.51	1,837,162	28,580,146	694,183	2.40	41.2
357.00 OTHER EQUIPMENT		35-R4	0	5,261,772.21	1,404,487	3,857,285	137,955	2.62	28.0
TOTAL UNDERGROUND STORAGE PLANT				**239,087,512.56**	**75,434,461**	**176,344,294**	**4,896,830**	**2.05**	
LOCAL STORAGE PLANT									
361.00 STRUCTURES AND IMPROVEMENTS									
LINNTON	06-2036	60-R2.5 *	(5)	12,498,961.89	5,008,053	8,115,857	658,612	5.27	12.3
NEWPORT	06-2042	60-R2.5 *	(5)	12,196,541.26	5,148,646	7,657,722	428,309	3.51	17.9
OTHER		60-R2.5	(5)	26,757.00	14,191	13,904	399	1.49	34.8
TOTAL STRUCTURES AND IMPROVEMENTS				24,722,260.15	10,170,890	15,787,483	1,087,320	4.40	14.5

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UG 527

OPENING TESTIMONY OF BOB JENKS AND EMILY DOUGAN
ON BEHALF OF THE OREGON CITIZENS' UTILITY BOARD

CUB 300

March 18, 2026

The Coos County Pipeline
The Coos County Distribution System

Q. Please state your name, occupation, and business address

A. My name is Bob Jenks. I am the Executive Director of the Oregon Citizen's Utility Board (CUB). My business address is 610 SW Broadway, Ste. 400, Portland, Oregon 97205. My Emily Dougan. I am a Utility Analyst employed by CUB. My business address is 610 SW Broadway, Ste. 400 Portland, Oregon 97205.

Q. Please describe your qualifications.

A. Jenks' witness statement is provided in Exhibit CUB/301 and Dougan's witness statement is provided in Exhibit CUB/302.

Q. What is the purpose of this Joint Testimony?

A. In this testimony, we will provide a brief history of the Coos County Pipeline (CCP) and the Coos County Distribution System (CCDS), why they were built, how they were funded, and what repair work needs to be done. We'll review to what extent NW Natural ratepayers and Coos County customers have already subsidized the operation of these pipelines highlight the shortfalls in funding for needed maintenance and capital recovery. We'll discuss demand trends and finally recommend three possible options for the future of the CCP, and how to recover the remaining capital costs associated with the CCDS.

Q. Are you sponsoring any exhibits?

A. Yes.

Exhibit 301	Dougan Witness statement
Exhibit 302	Coos County Distribution System Stipulation: Direct Testimony of Messrs. Dennis L.Henderson and Donald W. Schoenbeck, and Ms. Nikki Whitty. (March 4, 2003).
Exhibit 303	*In the Matter of Northwest Natural Gas Company's Application for a General Rate Revision: Testimony of the Citizens' Utility Board of Oregon on Coos County Pipeline Costs* (March 7, 2003)

Exhibit 304	Rivera, Dylan, Contractor loses suit over Coos County gas pipeline (Feb 24, 2009). Available at: https://www.oregonlive.com/environment/2009/02/contractor_loses_suit_over_ros.html
Exhibit 305	Public Data Request Responses
Exhibit 306	Senate Bill 32 Work Group Study of Natural Gas Expansion to Unserved Areas (Sept. 15, 2016) Available at: https://www.oregonlegislature.gov/citizen_engagement/Reports/PUC_StudyOfNaturalGasExpansionToUnservedAreas09_2016.pdf
Exhibit 307	Oregon PUC Public Meeting
Exhibit 308	*In the Matter of Northwest Natural Gas Company's Application for a General Rate Revision Coos County: Staff Testimony of Bonnie B. Tatom* (Mar. 07, 2003).
Exhibit 309	Coos County Distribution System Second Stipulation:Joint Testimony of Bonnie Tatom, Denis L. Henderson, Bob Jenks, Donald W. Schoenbeck, and Nikki Whitty (Apr., 09, 2003)
Exhibit 310	2024 Oregon Utility Statistics, Oregon PUC
Exhibit 311	Chapter 285B Economic Development 1999 Edition
Exhibit 312	Oregon Eyes Lottery Funds to Build Pipeline (Mar 8, 1999) Available at: https://naturalgasintel.com/news/oregon-eyes-lottery-funds-to-build-pipeline/
Exhibit 313	ADV 1789
Exhibit 314	SB 32
Exhibit 315	NWN response to CUB Conf DR
Exhibit 316	*In the Matter of OREGON PUBLIC UTILITY COMMISSION STAFF Natural Gas Fact Finding per Executive Order 20-04 PUC Year One Work Plan,* Docket No. UM 2178 Natural Gas Fact Finding Report (Jan. 31, 2023).
Exhibit 317	Public Comments from UM 2419 and ADV 1789
Exhibit 318	Rogue Climate Public Comments
Exhibit 319	Sierra Club Public Comments
Exhibit 320	GEI Public Comments
Exhibit 321	SB 76 on Klamath Falls dam decommissioning
Exhibit 322	Klamath Hydroelectric Settlement Agreement (KHSA)

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I. INTRODUCTION: A BRIEF HISTORY OF THE CCP AND CCDS

Q. Please briefly describe the history of the Coos County Pipeline.

A. In 1999, Coos County became interested in bringing natural gas services to the area to attract and grow industry in the region.[1] County officials approached the legislature, which approved a $70 million bond package for economic and community development programs, including $20 million for the Coos County Natural Gas pipeline.[2] The project had two parts: the Coos County Pipeline (CPP) that runs from the Williams pipeline to Coos Bay and the Coos County Distribution System (CCDS), which Northwest Natural built to provide gas service within Coos County.[3] This was part of an "economic

[1] *See* CUB/312 Jenks-Dougan.
[2] CUB/311 Jenks-Dougan/43.
[3] *See* CUB/302 Jenks-Dougan .

development project" undertaken by Coos County with support from the State of Oregon.[4] Specifically, it was designed to add "significant industries to locate in the area", increase employment, and support additional economic development.[5] The cost of the CCP was split between the state contribution of $20 million and $27 million charged to Coos County tax payers.[6]

Q. Please describe the history of the Coos County Distribution System.

A. On December 31st 2003, the Company filed a request for recovery of its investments in the CCDS in Coos County from residential and small commercial customers.[7] CUB opposed that treatment arguing:

> The Company is asking the Commission to include in the revenue requirement costs that are not economic and are being incurred to serve a significant volume of industrial load. But the Company is not asking industrial customers to share in the costs of service. This raises a fundamental question of fairness.[8]

Staff also opposed the Company's proposal, arguing that building the distribution system was governed by the Company's line extension policy for mains:

> A main extension is the piping and associated facilities required to extend service from the company's existing main facilities into an area not previously supplied to serve an applicant. Schedule X states how the construction allowance is determined for applicants and therefore, what construction contribution will be required to serve the applicant. If the allowance is greater than the cost of construction, the installation is performed at no charge to the applicant. If the cost of construction is greater than the construction allowance, the applicant must pay a construction contribution equal

[4] *See* Order No. 00-274 at 2; *see also* Order No. 02-678 at 3.
[5] CUB/308 Jenks-Dougan/16.
[6] CUB/311 Jenks-Dougan/43.
[7] CUB/302/Jenks-Dougan/9.
[8] CUB/303/Jenks-Dougan/3.

to the difference between the cost of construction and the construction allowance.[9]

Staff also expressed concern that if we ignored the line extension policy and asked customers of the larger gas system to subsidize this extension, it would set a precedent to extend the uneconomic service to communities unserved by natural gas.[10] Finally, Staff argued that spreading the entire cost to only residential and small commercial customers was "entirely inappropriate".[11]

As an alternative to its initial proposal, the Company, Coos County, and Northwest Industrial Gas Users (NWIGU) reached a settlement that placed a 1 cent surcharge on Coos County sales customers to help recover costs associated with the CCDS.[12] Any additional costs associated with the County's pipeline would be recovered from "all application NW Natural customers in Oregon in conjunction with the PGA mechanism"..[13] These parties agreed to place the $12 million cost of the Coos County Distribution System (CCDS) into system rates of sales customers beginning on the date of service.[14] Neither PUC Staff nor CUB supported this stipulation and instead called for an allocation of costs based on the Line Extension policy.[15]

Ultimately, NWN, Coos County and NWIGU agreed to apply the Line Extension policy, which limited what the system could pay to $10 million and required a 2 cent/therm

[9] CUB/308/Jenks-Dougan/7-8.
[10] *Id.* at 11.
[11] *Id.* at 15.
[12] *Id.* at 19-20.
[13] *Id.* at 21.
[14] CUB/302 Jenks-Dougan /9.
[15] *See* CUB/308/Jenks-Dougan and CUB/303/Jenks-Dougan/4.

surcharge on Coos County customers to recover $1.6 million, and NWN to contribute $400,000.[16]

At the time, there was concern that the Company's load forecast would not materialize, and thus a stipulation included the requirement that if the surcharge did not recover the Coos County allocation of $1.6 million, that NWN would set, "with the Commission's approval, an appropriate surcharge for Coos County customers until the entire balance has been paid."[17]

Q. Has demand on the CCDS materialized as expected by the Company?

A. No, the forecasted demand for the CCDS has not materialized and thus the initial investment remains unpaid.[18] CUB raised our concerns in UG 152 and we can see now that those concerns were warranted. The surcharge placed on Coos County customers never generated enough revenue to pay back the initial investment and has certainly not raised enough to cover ongoing O&M costs.

In response to OPUC IR 16 in ADV-1789,[19] the Company shows that demand growth in therms in year 1 to year 20 was much lower than predicted – with only 5.9 million therms per year as opposed to the estimated 7.9 million therms.[20] Thus, recovery of the initial investment was not recovered because of this 2 million therm shortfall. But now, through

[16] CUB/309/Jenks-Dougan/5.
[17] *Id.* at 6.
[18] CUB/305/Jenks-Dougan /116-117.
[19] CUB was granted permission to present Data Requests from ADV-1789 in this proceeding, *See* CUB/305/121 (ADV-DR 1, UG 527-DR 1).
[20] CUB/305/Jenks-Dougan/124.

years of mismanagement, the CCP is threatened by landslide activity, putting pressure on an already vulnerable community – and the funds meant to address this are nowhere to be seen.

It was anticipated by CUB in 2003 that demand might not materialize, and CUB supported the backstop that would revisit the CCDS surcharge and update it to collect the remaining amount.[21] Now, over 20 years later, we, unfortunately, see that our concerns were well founded. CUB does not wish to relitigate UG 152, whether this investment was prudent for the County or the Company in the first place, or to continue to criticize the Company for its miscalculations in the initial demand forecast. We were a party to the stipulation that implemented this agreement. Instead, we need to look at the work that needs to be done, and most importantly, determine who should shoulder these costs.

Q. To summarize, provide a brief timeline of the degradation of the CCP and this case.

A. CUB presents the history of problems concerning the CCP:

- 1990s: County officials become interested in bringing natural gas to the County through the expansion of a new main. They levy a bond from County taxpayers to fund this.[22]
- 2003: The County and NW Natural approach the Public Utility Commission to recover costs associated with the distribution system in the County.[23]

[21] CUB/309/Jenks-Dougan/6
[22] CUB/312/Jenks-Dougan.
[23] CUB/309/Jenks-Dougan/3.

- 2003: U.S. Army Corp of Engineers files suit against the County and MasTec Inc., the firm hired to build the pipeline, over Clean Water Act violations stemming from construction of the pipeline.[24]
- 2004: The County terminates its initial contract with the company hired to install the pipeline.[25]
- 2004-2009: The County and its contractor experience repeated lawsuits from environmental groups and residents, including counter-claims, ending in settlement and remediation plans related to water pollution and personal damages from construction of the pipeline.[26]
- 2021: NW Natural commissions a study to determine landslide risks along the pipeline and identifies 13 high risk sites.[27]
- Spring 2025: Heavy rains impact the area in March, leading to landslide activity that threatens the pipeline.
- Fall 2025: In October, the Company files to cancel charges for Coos County Customers and submits a proposal to purchase the CCP.[28]

II. CCP: WHERE ARE WE NOW?

Q. What work needs to be completed to remediate landslide risk, and what are the costs?

A. The Company is requesting an initial $12.2 million cost recovery for three project areas on the pipeline: Mile 98 at $4 million, Coquille River at $4 million, and an additional unnamed

[24] CUB/304/Jenks-Dougan/4-6.
[25] CUB/304/Jenks-Dougan/2.
[26] *See* CUB/ 304/Jenks-Dougan.
[27] NWN/200 Kizer-Karney-Pipes-Fellon/ 28.
[28] *See* CUB/313/Jenks-Dougan.

project site which it estimates will require $4.2 million in remediation work.[29] The Company currently has design plans for Mile 98 to relocate sections of the pipe and install it at a deeper location, but has not finalized design proposals for Coquille River or the third site.[30]

The Company identified 13 high risk areas in total in 2021 but is only requesting cost recovery for the sites listed above in this proceeding. The Company stated that it expects to incur additional O&M costs for pipeline management but has not estimated these, nor presented them in the filing.[31] However, in questions posed in discovery during ADV-1789, the Company estimated even higher landslide mitigation costs with O&M included – coming in at $13.2-14.7 million.[32] The Company also recognizes that sites like the Coquille River will likely require extensive environmental permitting as remediation will take place along the river's riparian area.[33] The Company offered in discovery that it does not believe this initial investment in landslide remediation will be its last.[34] The incongruence between the estimates in this filing and responses to data requests raises concerns for CUB.

Q. What is the lifespan for the CPP?

A. The Company estimates that for the three areas in which pipeline replacement will be needed, the depreciation of those replacements will be 67 years,[35] and that the remaining useful life on the rest of the CCP is around 29 years.[36] The contradiction between the long

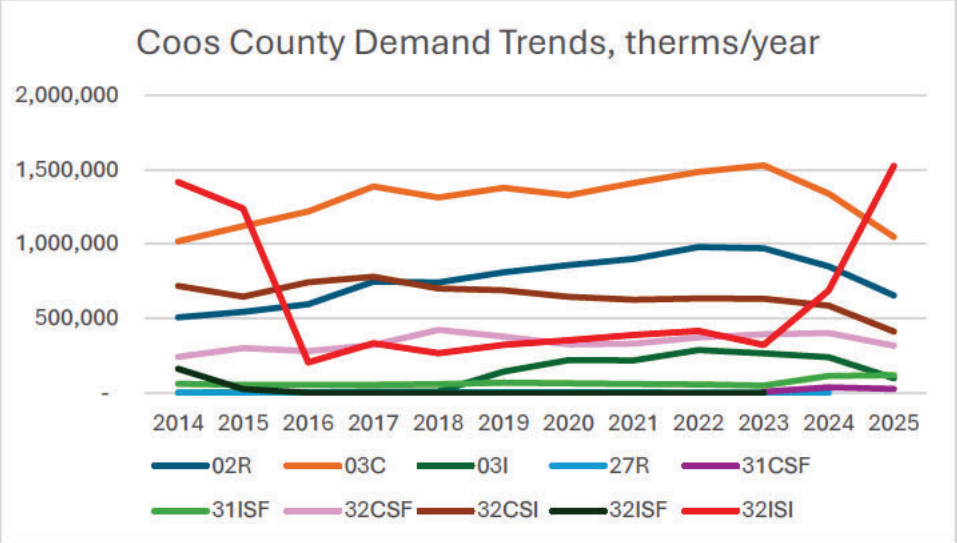
[29] NWN/200 Kizer-Karney-Pipes-Fellon/ 28-30
[30] Id.
[31] *See* CUB/305/Jenks-Dougan/120.
[32] *See* CUB/305/Jenks-Dougan/1.
[33] NWN/200/Kizer-Karney-Pipes-Fellon/ 31-32.
[34] *See* CUB/305 Jenks-Dougan/120.
[35] *Id.* at 123.
[36] *Id.* at 118

useful life of replacement parts compared to the pipeline itself makes little sense unless NWN plans to complete rebuild the CCP. Such a plan raises serious questions about prudency, used and usefulness, and the full costs that NWN expects its system to pay in relationship to the CCP.

Q. What have demand trends looked like in Coos County over the last 10 years?

A. The Company provided CUB with throughput demand data among all classes from 2014-2025 (see figure 1 below). While demand among commercial customers (03C) has stayed relatively stable, residential demand reached a high of only around 1 million therms in 2023. All customer classes, in fact, appear to be trending downward, apart from Interruptible Industrial customers (32ISI).

Figure 1: Coos County Demand Trends, therms/year[37]



[37] *Id.* at 115.

Q. Has the Commission ordered on similar cases to this in the past? Please provide an overview.

A. Yes and no. The situation in Coos County is relatively unique, as discussed above. However, there are instances similar to this case where the Commission has ordered alternatives to replacements or repairs of infrastructure. In UG 519 (Avista's last general rate case), the Commission adopted a stipulation that in lieu of jumping right into an expensive Aldyl-A pipeline replacement program, Avista first conduct a cap and prune, and targeted voluntary electrification (TVE) study and pilot.[38] This situation, too, involved the safety and energy security of customers served by the Aldyl-A pipe – but the Commission found it unreasonable to move forward without investigating alternatives first.

In UM 2026, the Commission ordered against Cascade Natural Gas's proposed automatic recovery mechanism for safety projects, arguing that the Company's proposal was "a departure from traditional ratemaking, which is done through a general rate case where a company's total revenues, costs, and rate base are evaluated to establish that rates are just, reasonable, and in the public interest**.**"[39]

In Order No.24-359, in regard to line extension allowances (LEAs), the Commission explained "we are concerned with plant costs that will remain in rates past the 25-year payback period and the potential for stranded asset costs if customers leave the system."[40]

[38] See Order No. 25-198 at 3.
[39] *See* Order No. 20-015 at 11.
[40] *See* Order No.24-359 at 10.

While an electric utility case that involved intervention from the Oregon Legislature, in UE 219 the Commission determined that the costs of relicensing PacifiCorp's Klamath River dams were too costly, and that transferring ownership of the dams and removing it was the most prudent option available.[41] Customers contributions for funding dam removal were capped, and amounts collected were remitted into specially created trust accounts to fund dam removal.[42]

Q. What relevance do you see in these to the filing at hand?

A. UG 519: CUB understands that the Aldyl-A pipeline replacement program involved service lines, not mains, but presents this to share how the Commission has required consideration of alternatives in other cases regarding infrastructure replacements and safety.

UM 2026: Order No. 20-015 in UM 2026 shows how the Commission has previously ordered on how gas utilities can and should recover safety related costs. UM 2269: While the Company taking ownership of the Coos County pipeline is not a *line extension*, we find the concern over the payback period and the risk of stranded costs in Order No.24-259 is relevant here. The Company is replacing sections of a pipeline that is 21 years into its 50 year useful life, with investments that have a 67 year useful life. This creates not just a risk of stranded costs, but a likelihood of stranded costs.

UE 219: Finally, as discussed more below, the order in UE 219 offers an example of how infrastructure can be removed with the creation of trusts to support replacement.

[41] *See* Order No.10-364.
[42] *Id.* at 5.

III. COOS COUNTY RESIDENTIAL IMPACT

Q. Please describe the impact of the proposal on residential customers living and working in Coos County.

A. As described by Rogue Climate;

> The average household income in Coos Bay is $55,292, highlighting the need for affordable sources of energy that can keep homes safe during any weather. 30-39% of households in Coos county are facing severe energy burdens while also earning less than $15,060 per year. As extreme weather events become more common, from heat waves to ice storms, families on the South Coast are increasingly burdened by high energy costs and power outages, highlighting the urgent need for affordable, climate-resilient solutions. As more and more customers across the state move off gas and choose more affordable and efficient energy sources, rural communities locked in to natural gas reliance will be forced to pick up the cost, resulting in skyrocketing bills.[43]

Rogue Climate is familiar with the community as it works alongside Southern Oregon and South Coast communities most impacted by climate change, including low-income, rural, youth, and communities of color. In their comments to this docket they note the local interest in electrification by these residents.[44]

The Coos County pipeline was built for economic development purposes to bring jobs to the port of Coos Bay. While demand is well below what was anticipated, there are industrial customers and jobs in Coos Bay that are dependent on the pipeline. As Rogue Climate notes, the Coos County Pipeline currently serves around 1,700 residential customers as well as the essential but underfunded Bay Area Hospital and Rosburg Forest Products.[45]

[43] CUB/318 Jenks-Dougan/2.
[44] *See* CUB/318 Jenks-Dougan CUB/319 Jenks Dougan, and CUB/320 Jenks Dougan.
[45] CUB/318 Jenks-Dougan/2.

Q. What should the Commission look to for guidance on how to assess the impact of the proposal on Coos County Residents?

A. The Commission should look to the public comments in this docket and the associated dockets. These can be found in CUB exhibit 316. The Commission should also consider its reflection on the proposal at public meeting on UM 2419, which can be found in CUB exhibit 307. Additionally the Commission should consider the findings of the Natural Gas Fact Finding Report, SB 32, and the prior history of lawsuits associated with the CCP. Additional consideration should be given to outside funding options and the timing of this proposal. These are discussed below.

Natural Gas Fact Finding Report

Q. What is the Natural Gas Fact Finding Report, and how does it relate to this filing?

A. The Natural Gas Fact Finding (NGFF) Report was an assessment completed by PUC Staff, regulated gas utilities, and stakeholders to explore how gas utilities can lower greenhouse gas emissions while reducing impacts on ratepayers and the system.[46] The report identified several topic areas and offered actions utilities should take during planning, programmatic and rate setting decision making periods. In one section, the report focuses on protecting customers with limited options (i.e., low-income customers, and business customers who rely on natural gas for a specific end-use).[47] As recommendations for rate making, the report offers the following action items:

- Include assessments of Climate Protection Program (CPP) compliance risks, like load growth from new customers, in prudency review of investments in the distribution system, in order to limit uncertainty around accumulation of long-term capital assets.

[46] *See* CUB/316 Jenks Dougan
[47] CUB/316/Jenks-Dougan/20

- Explore accelerated depreciation of unamortized investments in the gas utilities' next depreciation studies and provide sensitivity analysis to better understand rate impacts.
- Explore transport customer rate spread and rate design issues related CPP Compliance in general rate cases.[48]

Q. Has the Company incorporated these recommendations into its plan for the CCP?

A. Simply, no. While these recommendations are intended for rates and general rates cases, the Company has requested recovery of these costs outside of a general rate case, as discussed in CUB/100. From CUB's review of the record, the Company has not assessed CPP compliance risks regarding investments on the CCP. For example, the Company is not asking for the customers who most benefit (e.g. 32ISI) to shoulder a larger share of the costs through rate spread or rate design.

SB 32

Q. Please describe the outcome of SB 32 and how it relates to this filing.

A. SB 32 which was passed by the legislature in 2015 created a natural gas task force to study natural gas expansion to unserved areas in Oregon.[49] The work group found that communities interested in having gas service expanded to previously unserved areas should be the ones to pay for any costs beyond the allowance for new mains.[50] This is relevant to this filing as we determine who should be on the hook for the $12.4 million in repairs needed on the Coos County Pipeline.

Since the expansion of gas infrastructure to Coos County, other communities in Oregon have come forward seeking the build out of gas infrastructure, to bring natural gas to their

[48] *Id.* at 26.
[49] CUB/314/Jenks-Dougan/1.
[50] CUB/306/Jenks-Dougan/3.

communities for the first time. This led to the legislature establishing a task force managed by the PUC to analyze issues related to natural gas expansion.[51] Gas utilities wanted the Commission to allow for tariff riders and expanded line extension policies to pay for gas expansions – but the task force report determined that "new customers located within a previously underserved area will receive benefits from expansion (access to new service) and should be charged accordingly."[52] The settlement in UG 152 was 10 years before the SB 32 report, and limited NW Natural's ratepayers to funding the main extension allowance allowed under Schedule X, Coos County residents were required to pay a 2 cent per therm surcharge to recover the costs that were above the allowance. Though as explained this surcharge was not enough and $1.6 million of the original investment remains. So now, with outstanding costs associated with building the CCDS and major repairs needed on the CCDS, the community that would benefit from them does not have the load to support those costs.

Q. What is SB 32?

A. SB 32 was passed by the Oregon Legislative Assembly in 2015, as it found that "having access to natural gas is in the public interest and that the extension of natural gas pipelines and other infrastructure necessary for providing natural gas to areas that do not have access to natural gas is necessary for the communities of this state to preserve local economies, enlarge tax bases and generate additional economic opportunities".[53] As mentioned above, this legislation directed the PUC to form a work group to conduct a study on which methods a public utility should expand gas to previously unserved areas – and one of the findings

[51] CUB/314/Jenks-Dougan/1.
[52] CUB/306/Jenks-Dougan/3.
[53] CUB/314 Jenks-Dougan/1.

of this committee was that the communities requesting gas expansion were the primary beneficiaries and should pay for any costs above the main extension allowance.[54]

Q. Does CUB feel the Company has addressed concerns raised previously by the Commission and the SB 32 work group in its approach to the CCP?

A. No. The Company seems to ignore the concept that the amount of this investment that is supported by customers outside of Coos County should be capped and limited to amounts that are economic. It is not clear that the Company or the County has accurately weighed alternatives to the proposed remediation plan. The Company stated that they had not been approached by any other parties interested in purchasing the pipeline or funding the landslide work.[55] The Company also said it was not aware of any entities that had approached the County with proposals to purchase the pipeline but could not say for sure.[56] This is a passive approach, not an exploration of alternatives. Without an examination of possible alternatives, which should provide a firm answer to the question of whether there were other entities considering proposals to purchase the pipeline, it isn't possible for us to determine if Northwest Natural is the right fit.

Prior lawsuits associated with the CPP

Q. What can you tell me about the prior lawsuits associated with CPP?

A. The CPP has been plagued with legal problems as laid out in CUB exhibit 304. For example, a Coos County lawsuit in 2004 against MasTec, a contractor for the CPP, cited numerous problems with the construction of the pipeline, including four lawsuits from

[54] CUB/306 Jenks-Dougan .
[55] CUB/305 Jenks-Dougan/2
[56] Id.

private landowners against the County alleging damaged private property during construction. According to the lawsuits, while drilling underneath stream beds, MasTec employees caused the ground to fracture and drilling lubricants to ooze into at least five local streams.[57] MasTec and the County sued each other in a case that took four years to reach settlement. MasTec agreed to pay Coos County $8.7 million and dismiss its claims against the County, which totaled $14.5 million.[58]

Additionally, a coalition of groups (including property owners) sued the County in district court for Clean Water Act violations which resulted in a $1.5 million fine to MasTec. The Oregon Department of Environmental Quality also fined MasTec $205,000, then settled for $63,000. Additionally, in September 2003, the U.S. Army Corps of Engineers filed suit against both the County and MasTec. This resulted in fines and an MOU resolving claims of Clean Water Act violations against the County stemming from the 2003 construction of the natural gas pipeline from Coos Bay to Roseburg. The MOU required environmental remediation to the streambeds.

These past lawsuits are relevant to consideration of the risks at hand for landowners and ratepayers and evaluation of the prudency of NWN's proposal. Public comments in this docket show that ratepayers are concerned with paying for pipeline leaks and aging infrastructure fixes, and point to these past lawsuits. Likewise the community cites to these lawsuits and concerns over the risks to their fragile coastal ecosystem. They raise the risk of natural disasters, including from the Cascadian subduction zone earthquake event and/or

[57] CUB/304 Jenks-Dougan/8.
[58] *Id.* at 2.

tsunami.[59] As NWN works to replace the pipeline it does so in an area prone to landslides. It risks further erosion and water pollution lawsuits similar to those discussed above. It risks the potential for costly environmental remediation and landowner property damage. But its customers who will pay for these risks.

Funding the Remediation

Q. Has the County received additional support or funding as an alternative to NWN's purchase?

A. The County has received grants and funding to tackle some of the pipeline work. The County was granted American Rescue Plan Act (ARPA) funds, which it allocated $1.45 million to mitigate risk at the Coquille River project.[60] The County has also attempted to obtain a FEMA Building Resilient Infrastructure and Communities grant, but the program was cancelled because of the federal shutdown in fall 2025 and has not reopened.[61] The Company received some FEMA dollars after the March 2025 storms but has been informed this funding cannot go toward relocating the pipe.[62] Finally, Coos County does still maintain a pipeline fund used for landslide mitigation work, which the Company reported is currently at $600 thousand.[63]

[59] CUB/318 Jenks-Dougan/1.
[60] CUB/305 Jenks-Dougan/122.
[61] Id.
[62] Id.
[63] CUB/305 Jenks-Dougan/122.

Q. What concerns does CUB have about the timing of NWN's request to purchase the line?

A. As shown above and in the Company's initial filing, the Company commissioned a study to identify landslide areas near the pipeline in 2021.[64] Further, the Company states in the filing that signs of erosion were seen at the Coquille River site as early as 2020.[65] Thirteen areas were identified as high risk – yet the Company waited another 4 years to act on this. As the Company recounts, in March 2025 heavy rains put further stress on the pipeline. If this truly is as imminent of a safety threat as the Company would like us to suppose (which CUB agrees it may be, especially now given the storms last spring), and the Company knew of this risk four years ago, it is truly not fathomable why it has waited so long to act. If the Company waited so it could align this purchase of the CCP with the 20 year review of the CCDS, it suggests that the risk isn't really immediate. Additionally, in its 2022, 2023, 2024 , 2025, and 2026 Annual Oregon Safety Project Plan, plans for landslide remediation at the CCP are nowhere to be seen.[66] CUB also questions why, again if this is an urgent safety issue, the Company has not finalized proposals for remediation at *all* sites. This is highly problematic. If the Commission places the costs of remediation of some sites, those investments may only be used and useful if all sites (and possibly additional sites) are remediated. It is not clear what we are getting into with this transaction.

Q. Have the Commissioners weighed in on this transaction?

A. Yes, in the OPUC Public Meeting on February 3, 2026, Commissioner Karin Power raised the question of "whether NW Natural's rate base should absorb significant ongoing

[64] NWN/200 Kizer-Karney-Pipes-Fellon/28-29
[65] *Id.* at 31.
[66] *See* CUB/305 Jenks-Dougan/3-114 (UG 527 OPUC DR 47, NWN Safety Project Plans included as attachments 1-6)

structural issues"[67] and concerns of "shareholder utilities stepping in to absorb locally owned infrastructure that they can no longer maintain on their own."[68] CUB echoes these concerns and the precedent this sets.

Q. What do you make of these concerns?

A. This brings us to the crux of the issue with this pipeline: per cost causation principles and SB 32, County customers *should* be on the hook to incur an extra charge for the needed $12.4 million landslide maintenance. However, with just a monthly therm usage of 33,1450 averaged out for all rate classes from 2016 to 2025,[69] that surcharge would need to be raised for the average rate payer in the County – a 21cent surcharge per therm for timely recovery.[70] If applied to residential and commercial schedules only, this would raise the surcharge to 79 cents per therm.[71] At the same time, system ratepayers have *already* made substantial contributions to the expansion of the gas system in the County in 2005 – thus it is unfair to continue to ask them to continue to do so.

Q. Could industrial customers cover these costs?

At the PUC Public Meeting on February 3, 2026, Chair Tawney expressed her interest in seeing industrial customers in Coos County play a role in amortization.[72] The industrial

[67] CUB/307/Jenks-Dougan/78-79.
[68] *Id* at 80.
[69] The monthly usage averaged out amongst all rate schedules from 2016-2025 was 33,145 therms per month. *See* CUB/306/Jenks-Dougan/115-117. Note that the Coos County surcharge was initially only applied to residential and commercial customers.
[70] Assuming a recovery of 29 years, the remaining useful life of the CCP and the ongoing $400,000 necessary in yearly O&M as discussed in ADV-1789, the Company would need to recover $827,600 per year. With the average usage of all customers this comes out to a .21 cent per therm surcharge.
[71] Assuming a recovery of 29 years, the remaining useful life of the CCP and the ongoing $400,000 necessary in yearly O&M as discussed in ADV-1789, the Company would need to recover $827,600 per year. With the average usage of R2 03C and customers this comes out to a 79 cents per therm surcharge.
[72] CUB/307/Jenks-Dougan/84 (Chair Letha Tawney stating "And I am not comfortable with an amortization that would place this on residential customers more broadly. I think that there is a really important role for industrial customers in Coos Bay").

load on the pipeline is 42% of the total load.[73] CUB has considered another option to place this surcharge on rate schedules seeing increased usage in the County (e.g. Interruptible Industrial 32ISI), but calculating the average monthly demand in this schedule alone would also require a substantial, unattainable surcharge.[74] Increasing costs from the Climate Protection Program (CPP), that industrial customers are now on the hook for paying themselves, will continue increasing their costs and potentially lowering their demand. Additionally, through discovery CUB learned that the 32ISI schedule has only **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** customers in the County currently.[75] At the same time, CUB recognizes that the CCP and the CCDS serve industrial load that provides jobs in a community that has struggled. Quite simply, there are no optimal solution – no win-win alternatives – to the CCP.

Q. What about the CCDS?

A. There are no good solutions here either. The original agreement that CUB supported proposed required NWN to evaluate a new surcharge that would collect the remaining $1.6 that remains of the initial Coos County investment. However, because this number is identical to the number 20 years ago, expecting the limited number of customers there to pay for the pipeline would be a large commitment.

[73] *See* CUB/305/Jenks-Dougan/115-117.
[74] Assuming a recovery of 29 years, the remaining useful life of the CCP and the ongoing $400,000 necessary in yearly O&M as discussed in ADV-1789, the Company would need to recover $827,600 per year. With the average usage of 32ISI customers this comes out to a $1.3 per therm surcharge.
[75] CUB/315C Jenks-Dougan/2.

Q. NWN argues that Coos County customers are poorer than the rest of the state, so they should not be surcharged?

A. Coos County customers were also poorer 20 years ago when the original surcharge was adopted. But it is important to recognize that:

- The Oregon coast has a milder climate than most of NWN service territory. The 1,793 residential customers in Coos County used 365 therms in 2025[76], whereas the average load of all residential customers is greater than 600 therms/year.[77] So without a surcharge, Coos County customers pay a lower share of the fixed costs of distribution pipes.
- Today Coos County customers who meet income qualifications are eligible for the original surcharge.

Q. Please summarize how NWN's ratepayers have paid for the expansion of gas service.

A. To summarize who has paid for this pipeline in Coos County to date:

- County taxpayers have paid for the CCP through the bond measure to build it;
- County ratepayers have paid a surcharge for continued maintenance and operation of the CCP;
- Because that surcharge is not large enough to pay for the County's share of the CCDS, NW Natural ratepayers continue to pay for the expansion of the distribution gas system (CCDS) throughout the County, under the terms of the Schedule X that was in place when the CCDS was built;
- All NWN customers pay O&M costs through the PGA;

[76] *See* CUB/305/Jenks-Dougan/115-117 showing 2025 Coos County load by class, divided by 1,793 customers in 2025.
[77] CUB/310/Jenks-Dougan/53.

Q. How is NWN proposing to pay for these costs going forward?

A. NWN has proposed eliminating the surcharge altogether and instead placing this charge on all sales customers as an equal percent of margin, this means that residential customers would pay 66.6% of the cost.[78] But in 2025, residential customers were only 15.45% of the natural gas load in Coos County.[79] In addition, these costs were incurred to support industrial economic development placing them primarily on residential customers does not seem fair. Finally, the original agreement said that Coos County customers should continue to pay an adjusted surcharge to pay for the remaining cost of the CCDS. While there are so few customers, this might be problematic, but relieving them of any responsibility does not seem to fair.

IV. BURDEN OF PROOF

Q. Did NWN consider alternatives to replacement of the CPP sections after receiving the results of the 2021 study identifying landslide areas near the Coos County Pipeline?

A. The record does not support a finding that NWN considered any alternatives. Already this pipeline's cost and repairs have exhausted the budget of the County. Under NWN's solution these ongoing costly repairs will be pushed onto its ratepayers. The Company and County should first have to fully investigate alternatives and should not be given carte blanche to add new segments of the pipe that will remain in base rates for decades – even under emergency conditions.

[78] *See* NWN/101 Kravitz-Walker/2.
[79] CUB/305 Jenks-Dougan/115-117.

Q. Has the Company met its burden of proof that it should be allowed to recover the $12 Million CCP replacement costs?

A. Under ORS 757.210(1)(a), NWN bears the burden of showing that a proposed rate is fair, just, and reasonable. While, this is a difficult situation, that does not mean that this burden is lowered or that NWN's proposal is by default fair, just and reasonable. Based on the current load in Coos County, it is not economic for the system to continue to put millions of dollars into supporting this project. And to the degree this is being done for economic development and jobs in Coos County, this is not a basis for the Oregon PUC to raise rates to residential customers throughout its system.

Q. Is this ARM the appropriate place to recover these costs?

A. Single-issue ratemaking presents certain risks and shortcomings in the regulatory process, and adds increased risks to customers that rates depart from being cost-based and subject to the normal reviews for overall reasonableness.[80] For this reason, before the Commission can authorize cost recovery under this ARM, NWN must demonstrate that circumstances *warrant an exception* to typical rate recovery, including that the benefits of using an ARM approach justify its use when compared to the detriments associated with it.[81]

When presented with a similar question of the standard for recovery of pipeline replacement in a single-issue mechanism, the SCRM, the Commission found it would "require more than a showing that the projects are related to safety. In other words, we do not deem an SCRM to be appropriate for all safety-related costs."[82] Likewise, before

[80] Order No. 20-015 at 11.
[81] *Id.*
[82] *Id.* at 11-12.

approving this ARM for recovery of the CCP investments, NWN must identify that this mechanism is necessary for this recovery, *i.e*., "whether the company would be able to complete the necessary investments and achieve cost recovery in a reasonable manner under traditional ratemaking, or if recovery of incremental costs between rate cases is needed to ensure the company has the ability and incentives to complete those investments in an appropriate timeframe."[83] While there may be urgency to *mitigate* the landslide risk, the record does not support transposing that urgency to the *recovery* of the pipeline replacement costs outside of traditional ratemaking.

For example, NWN has not demonstrated that it lacks the incentive or ability to complete the CCP projects without use of the ARM. NWN has maintained and operated the CCP in the past absent use of an ARM. And NWN has replaced pipeline on its system in the past without use of an ARM. As NWN testifies, these CCP projects are likely to be ongoing phases of pipe replacement projects as the pipeline is located in a landslide area.[84] We also note that NWN seems likely to file one or more future rate cases in timeframes that make it workable to review the investments in those proceedings. These are the same factors the Commission considered when it denied Cascade's recovery in Order No. 20-015. Under this same reasoning, the record here does not support a finding that the ARM is superior to relying on traditional ratemaking approaches for the associated cost recovery of the CCP.[85] The Commission can both acknowledge the Company's decision to undertake these projects to ensure safe and reliable service while also finding that the record does not

[83] *Id.* at 12.
[84] CUB/305/Jenks-Dougan/120.
[85] *Id.* at 13.

support that specialized ratemaking treatment of an ARM for the capital investment associated with this pipeline replacement.[86]

V. ALTERNATIVES

Q. Given all of this, what does CUB recommend?

A. Because of the complexity of this situation, CUB offers three potential options for the CCP and one proposal for the CCDS. We admit that this feels like an impossible situation. Per findings from SB 32, communities should cover the costs of gas expansion that supports their economic growth. NW Natural ratepayers should not be on the hook to remediate a pipeline and a distribution system that was based on faulty, misinformed data and that ultimately should not have been built in the first place. But it was built, customers did pay, and - now because of NW Natural's delay in addressing landslide vulnerabilities identified 4 years ago – the pipeline and energy security in Coos County are at serious risk.

CCP

CUB offers three potential paths forward to collect the costs associated with the CCP. While none of these are perfect, and will require further discussion, we offer them for consideration:

- **<u>Option 1: Decommission the pipeline.</u>**
    - The first option CUB proposes is to decommission the pipeline. This option is supported by public comments across the related dockets.[87] CUB recognizes that an unanticipated closure of the pipeline would have significant negative effects on the entire region and that is not our goal. In this option then, the pipeline will be decommissioned after a 5-7 year grace

[86] *See Id.* at 14.
[87] *See* CUB/318 Jenks-Dougan; CUB/319 Jenks-Dougan; CUB/320 Jenks-Dougan.

period. In that time, the Company, the County and local electric utilities will create a strategy to fuel switch customers quickly and cost effectively. Funding to recover the costs of decommissioning the pipeline will be collected from ratepayers for a period to be determined by the Commission, which could look something like the fund to pay to decommission the Klamath Falls dams, whereby there was an interest-bearing trust account to pay for the decommissioning costs and customer contribution cap on how much customers pay towards decommissioning (see UE 219).[88]

CUB finds this option reasonable as there is no indication that the $12.4 million requested for landslide remediation will be a complete solution to landslide risk. Additionally, as demand in the County is low, and too low to recover landslide remediation costs from County ratepayers alone, the prudency of keeping this pipeline in operation is questionable.

- **Option 2: Split remediation cost recovery between rate payers and the Company.**

In this option, ratepayers pay 50% of the $12.4 million in cost recovery and the Company pays the remaining out of shareholder profits, and/or charges to Coos County customers or taxpayers. The costs would be allocated to customers based on the load that is serving Coos Bay, updated each rate case. Figure 2 below shows the allocation for 2025.[89]

[88] *See* CUB/321 Jenks-Dougan and CUB/321 Jenks-Dougan.
[89] CUB/305/Jenks-Dougan/115-117

Figure 2 costs based on the load that is served by these investments[90]

Rate Schedule	percent of cost
02R	15.46%
03C	24.76%
03I	2.32%
27R	0.00%
31CSF	0.62%
31ISF	2.79%
32CSF	7.47%
32CSI	9.73%
32ISF	0.84%
32ISI	36.02%

CUB feels this option is reasonable as the Company has yet to take *any* risk in the maintenance of the pipeline, and these risks should not be put solely on customers. CUB would also recommend a caveat that the amount recovered from customers is capped at $6.2 million Any additional maintenance needed on the pipeline would need to be brought to the Commission and intervening parties in a GRC to determine next steps.

If this option is chosen, CUB also recommends two additional requirements. First to avoid stranded costs, CUB recommends that the useful life of the replacement pipe be aligned with the useful life of the CCP itself and these costs would be amortized over the life of the CCP. The Company has shared that the depreciation estimates for the newly installed portion of the pipes is 67, while the entire pipeline itself only has a 29-year life.[91] If the pipeline's life ends in 29 years, that will then limit the useful life of the new additions. Thus, the lifespan of the current pipeline must be used for the

[90] CUB/305/Jenks-Dougan/115-117.
[91] *Compare* CUB/305 Jenks-Dougan/118 (noting the depreciable life of the CCP is 50 years and was placed into service in 2005) *with* CUB/305 Jenks-Dougan/123 (noting 67 and 80-100 year lives for replacement).

lifespan of the group depreciation, not the average between the useful life of the replacements and the pipe. Second, the Company should be required to produce an independent study which estimates the full cost of repairing and maintaining the CCP for the next 29 years. The study should be submitted to the PUC and parties to this case by January 1, 2028.

- **Option 3: The Company pays for the remediation costs in full through shareholder profits.**
  - In this option, the Company covers the full cost of remediation through shareholder profits. The Company has stated several times that this is an issue of environmental justice, energy resiliency, safety, and economic development. But this pipeline also allows NWN to sell gas to customers in Coos County, increasing Company revenues. The Company is also proposing to spread these costs over 67 years so the cost per year is small. Thus, we feel it is reasonable for the Company to invest financially in achieving this. CUB understands that this option is likely the least desirable to the Company but there is little evidence that this investment is cost effective for the system.

CCDS

For the CCDS, CUB recommends that the Coos County surcharge be maintained but adjusted for inflation. It was proposed in 2003, so today it would be 3.55 cents/therm. CUB recommends that it be updated for inflation in every GRC. For the remainder of the costs, CUB proposes that they be allocated to customers classes based on each class's share of the load in Coos County. More than 20 years ago in UG 152 CUB argued that the ideally these costs would be allocated to customer classes based on the projected load for that class but we

had no faith in the Coos County load forecasts that NWN was projecting.[92] Today we have the knowledge to allocate these costs based on the load that is served by these investments.[93] This is shown in Figure 2 above.

VI. CONCLUSION

Q. Please summarize testimony and your recommendations.

A. In 2003, it was predicted by stakeholders in UG 152 that the surcharge on Coos County customers would never be enough to recover costs or O&M for the pipeline due to low demand. 20 years later, we clearly see this was not just a prediction but reality – and the County and the Company has been unable to maintain the pipeline. To avoid re-litigating the past, and deal with the situation at hand, CUB has proposed three options, and recommends:

- Adopt Options 1, 2 or 3 as discussed above regarding the CCP.
- Update the CCDS surcharge based on inflation and allocated based on historical rate class usage.

Q. Does this conclude your testimony?

A. Yes.

[92] CUB/303/Jenks-Dougan/29.
[93] CUB/305/Jenks-Dougan/115-117.

WITNESS QUALIFICATION STATEMENT

NAME: Emily Dougan

EMPLOYER: Oregon Citizens' Utility Board of Oregon

TITLE: Utility Analyst

ADDRESS: 610 SW Broadway, Suite 400
Portland, OR 97205

EDUCATION: Bachelor of Science, Earth and Environmental Science
Willamette University, Salem, OR
Master of Science, Urban Environmental Management
Wageningnen University, Wageningnen, NL

EXPERIENCE: Provided comments on LC 86 and opening testimony in UG 525.

Between 2023 and 2025, worked for the Environmental Protection Agency's Get the Lead Out Initiative, aimed at identifying and removing lead service lines in water systems across the U.S.

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

COOS COUNTY DISTRIBUTION SYSTEM STIPULATION

NW Natural

Joint Direct Testimony of
Messrs. Dennis L. Henderson and Donald W. Schoenbeck,
and Ms. Nikki Whitty

March 2003

DOCKETED

Q. Please state your names and positions.

A. My name is Dennis L. Henderson. I am employed by Northwest Natural Gas Company ("NW Natural") as the General Manager of the company's Industrial-Commercial Business Solutions Department. I have previously filed testimony in this docket.

My name is Donald W. Schoenbeck. I am a principal of Regulatory & Cogeneration Services, Inc., which is employed as a consultant in this docket by the Northwest Industrial Gas Users ("NWIGU"). My qualifications are attached as Exhibit 1509.

My name is Nikki Whitty. I am one of three elected County Commissioners for Coos County, Oregon.

Q. What is the purpose of your Joint Testimony?

A. The purpose of our Joint Testimony is to describe and support the Stipulation Relating to the Coos County Distribution System (the "Stipulation") between NW Natural, NWIGU, and Coos County (together, the "Parties"). *See*, Exhibits NWN/1510 – 14.

Q. Please describe the background for this Stipulation.

A. Pursuant to Commission orders issued in 1965 and 2000, NW Natural holds exclusive rights to provide natural gas service in Coos County under the Territory Allocation Law, with the exception of the City of Bandon. The company presently provides propane service in Coos County. The 1999 Oregon Legislative Assembly approved funding for Coos County to construct a gas transmission

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pipeline that would route natural gas from the Williams pipeline, at a point near Roseburg, to the south coast. Coos County voters authorized general obligation bonds to cover the balance of the cost of construction.

On July 30, 2001, NW Natural and Coos County entered into a Transportation Service Agreement under which NW Natural agreed to construct certain minimum distribution facilities on a schedule designed to get gas to customers soon after the County's pipeline is completed. NW Natural will serve its distribution customers by transporting its own gas through the interstate pipeline, purchasing gas transportation services on the County's pipeline, and then delivering gas on its local distribution system to customers under appropriate tariffs. NW Natural may also provide local gas transportation services to industrial customers, from the County pipeline to the customer's facilities. The Agreement contains several conditions precedent to NW Natural's obligation to construct a distribution system, including Commission approval of the Company's proposal concerning statewide rate treatment of the initial investment in Coos County distribution.

On December 31, 2001, NW Natural filed a request for statewide rate treatment of its Coos County investment. The request was docketed as UG 147 but was converted, at the Commission's request, to a declaratory ruling petition that was docketed as DR 30. Through most of 2002, the parties to DR 30 participated in workshops, stipulated to a single set of assumed facts, and briefed the legal issues. When a parallel application, Docket UA 93, was denied

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in October, the Commission held DR 30 in abeyance pending notice from NW Natural on whether it wished to continue DR 30. NW Natural delivered a notice of its intent to continue DR 30 on November 4, 2002. Subsequently, NW Natural, NWIGU, and Staff discussed the possibility of resolving the Coos County rate proposal in the context of NW Natural's anticipated general rate case. On November 25, 2002, NW Natural filed a request with the Commission to hold DR 30 proceedings in abeyance. On November 29, 2002, NW Natural filed an application for a general rate revision and included its Coos County rate proposal. The DR 30 docket was closed on December 11, 2002 and an expedited schedule for the Coos County issue was established in this rate case on January 10, 2003. The Parties reached agreement on the terms of the Stipulation at the end of February.

Q. Please summarize the Stipulation.

A. The Stipulation covers the same issues set forth in NW Natural's prefiled testimony, Henderson, NWN/1500. The Stipulation defines the scope of costs included in the initial investment; the Parties support the Company's proposal to place the revenue requirement associated with that initial investment into rates, effective with the distribution system's in-service date, subject to audit and review procedures. The Parties also support the Company's proposed mechanism for collecting a surcharge from Coos County sales customers to recover the costs of transportation capacity on the County's pipeline. Subject to certain conditions, the Parties support collection of the balance of such costs, after the surcharge,

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from all Oregon sales customers. Finally, the Company agrees that, following initial construction of the distribution system, it will extend natural gas to Coos County customers according to Schedule X, the Company's line extension policy.

The Stipulation represents a negotiated compromise among the Parties. Thus, the Parties have agreed that no Party shall be deemed to have approved the facts, principles, methods, or theories employed by any other in arriving at the Stipulation, and that the terms incorporated in the Stipulation should not be viewed as precedent in subsequent proceedings. In addition, the Parties have the right to withdraw from the Stipulation if any material part is rejected by the Commission, and the Parties remain free to pursue any appropriate course of action with respect to any issue or matter in this proceeding that is not covered by the Stipulation.

Q. What do the Parties recommend regarding the Stipulation?

A. We recommend that the Commission admit the Stipulation into the UG 152 record and adopt the Stipulation in its entirety in determining the rate treatment of NW Natural's initial investment in a Coos County distribution system.

Q. Does this conclude your Joint Testimony?

A. Yes.

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

COOS COUNTY DISTRIBUTION SYSTEM STIPULATION

NW Natural

Joint Direct Exhibits of
Messrs. Dennis L. Henderson and Donald W. Schoenbeck,
and Ms. Nikki Whitty

March 2003

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NW NATURAL COOS COUNTY DISTRIBUTION SYSTEM STIPULATION

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PROFESSIONAL EXPERIENCE

Mr. Schoenbeck was employed at a large Midwest investor-owned electric and gas utility from 1972 to 1980. While in the transmission and distribution function of the utility, Mr. Schoenbeck was responsible for various special studies related to end-use energy consumption, transformer load management, distribution line configurations, and statistical sampling. In the rates function, he assisted in the preparation of electric, gas, steam, and water tariffs and rate filings for presentation to the several state regulatory commissions and the Federal Energy Regulatory Commission. Upon transferring to the corporate planning function, Mr. Schoenbeck developed computer programs that forecasted various corporate financial statements used by the officers of the company, board of directors, and financial rating agencies.

Mr. Schoenbeck has been a consultant in the field of utility regulation since 1980, offering a broad base of experience in various natural gas, electric, and cogeneration matters. His responsibilities have included:

* power cost forecasting
* avoided-cost pricing
* contract negotiations for gas and electric services
* natural gas storage, transportation, and balancing provisions
* siting and licensing proceedings
* computer model simulation
* capacity need determination
* rate case proceedings involving deregulation, decoupling, revenue requirement determination, cost-of-service and rate design issues
* audits of utility power costs.

WITNESS EXPERIENCE

Mr. Schoenbeck has appeared as an expert witness before the state regulatory commissions of Alaska, Arizona, California, Delaware, Illinois, Montana, Nevada, North Carolina, Ohio, Oregon, Washington, Wisconsin, and Wyoming. In addition, he has presented testimony before the Bonneville Power Administration, the Federal Energy Regulatory Commission, the National Energy Board, publicly owned utility boards, and in court proceedings in the states of California, Washington and Oregon.

EDUCATIONAL BACKGROUND

Mr. Schoenbeck holds a Bachelor of Science degree in Electrical Engineering and a Master of Science degree in Engineering Management from the Universities of Kansas and Missouri, respectively. In addition, he has completed all the course work for a Master of Science degree in Nuclear Engineering.

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BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UG 152

In the Matter of NORTHWEST NATURAL GAS COMPANY Application for a General Rate Revision	Stipulation Relating to the Coos County Distribution System

This Stipulation is entered into between Northwest Natural Gas Company ("NW Natural"), the Northwest Industrial Gas Users ("NWIGU"), and Coos County (together, the "Parties"). The purpose of this Stipulation is to resolve all issues between the Parties relating to the treatment, in this Docket, of NW Natural's investment in a Coos County natural gas distribution system (the "CCDS").

The terms and conditions of this Stipulation are set forth below.

1. **Rolled-In Rate Treatment**

The Parties agree to accept and support NW Natural's proposal to place the revenue requirement associated with the initial investment in the CCDS into rates effective with its in-service date, provided that the initial investment is subject to continuing audit by the Commission Staff and Parties to ensure that only actual, prudently incurred costs are recovered. "Initial investment" includes NW Natural's construction and associated costs, as well as operations and maintenance expense, incurred during the Initial Construction Period to build mains, service lines, and other distribution facilities and appurtenances in the cities of Coos Bay, North Bend, Coquille, and Myrtle Point, including a pipeline connecting the Coos Bay/North Bend distribution system to the North Spit industrial area. "Initial Construction Period" means the first 15 "construction months," or those months of the year during which weather conditions allow active construction to occur, beginning when NW Natural commences construction of the CCDS. The estimated cost of such initial investment is $12 million.

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2. Coos County Transportation Surcharge

The Parties agree to accept and support NW Natural's proposal to impose a $0.01-per-therm surcharge on Coos County natural gas sales customers (the "Coos County Surcharge"), to recover the costs of transportation capacity on the natural gas transmission pipeline owned by Coos County. The Coos County Surcharge is summarized in Rate Schedule 1G, Tariff P.U.C. Or. 23, as proposed in this Docket, and would apply to all sales service customers connected to the CCDS. The Coos County Surcharge may be adjusted annually at the time of the company's purchased gas adjustment filing, to reflect any increases or decreases in the costs of transportation capacity on the Coos County pipeline. Upon the abandonment of the Company's Tariff P.U.C. Or. 23, the provisions and conditions contained in Schedule 1G will be incorporated into the company's Tariff P.U.C. Or. 22.

3. Statewide Collection of Coos County Pipeline Demand Charges

The Parties agree to accept and support NW Natural's proposal to collect, statewide, any balance of Coos County pipeline demand charges not recovered through the Coos County Surcharge as part of NW Natural's annual purchased gas adjustment. Specifically, NW Natural would spread any such balance to all NW Natural's Oregon sales service customers in the same manner as other pipeline demand charges, as set forth in the company's filed Tariff, Schedule 169, "Purchased Gas Cost and Weighted Average Cost of Gas." The charge would apply to all Oregon sales service customers; it would not apply to transportation customers who do not otherwise pay pipeline demand charges to NW Natural through a tariffed rate.

Annually, in the purchased gas adjustment, NW Natural agrees to reassess the Coos County Surcharge to determine whether it is sufficient to recover NW Natural's cost of transportation on the Coos County pipeline. At the point any such assessment shows that the Surcharge is sufficient (the "Breakeven Point"), NW Natural agrees to terminate statewide recovery of the balance of the transportation costs from its Oregon sales service customers.

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Following the Breakeven Point, NW Natural's transportation costs on the Coos County pipeline would be recovered only from Coos County sales service customers, with no further recovery from Oregon customers outside Coos County.

4. Line Extension Policy and Tariff Application

NW Natural agrees that, following construction of the initial CCDS (as described and defined in Section 1), the company's line extension policy, as set forth in the company's Tariff P.U.C. Or. 22, Schedule X, and any successor tariff, will govern extensions of natural gas distribution service to potential gas customers in Coos County who request such service. Following construction of the initial CCDS, all of the company's sales and transportation service schedules set forth in Tariff P.U.C. Or. 22 will be made available to potential gas customers in Coos County who request such service.

5. General Terms and Conditions

(a) The Parties agree that this Stipulation represents a compromise in the positions of the Parties. As such, conduct, statements, and documents disclosed in the negotiation and discussion phases of this Stipulation shall not be admissible as evidence in any proceeding before the Commission or a court.

(b) The Parties agree that with respect to the issues covered in this Stipulation, this Stipulation is in the public interest and all of its terms and conditions are fair, just, and reasonable.

(c) The Parties will cooperate in submitting this Stipulation promptly to the Commission for acceptance and will support adoption of the Stipulation in testimony and argument submitted in this proceeding. The Parties may also offer into the record of this proceeding those portions of the record from Commission Docket DR 30 deemed relevant to support this Stipulation. If a hearing is scheduled for presentation of the Stipulation, each Party must make available a witness in support of this Stipulation. If the Commission rejects all or any material portion of this Stipulation or imposes additional material conditions in approving

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this Stipulation, any Party disadvantaged by such action has the right, upon written notice to the Commission and all parties to the proceeding within 15 days of the date of the Commission's Order, to withdraw from this Stipulation. If any Party withdraws from this Stipulation as permitted in this subsection, no Party to this Stipulation will be bound or prejudiced by the terms of this Stipulation, and each Party will be entitled to seek any remedy set forth in Oregon Administrative Rule 860-014-0085(6) or other applicable law, rule, or order; and in general to put on such case and pursue such course as it deems appropriate and the law allows.

(d) Execution of this Stipulation does not constitute an acknowledgment by any Party of the validity or invalidity of any particular method, theory, or principle of regulation, and no Party may be deemed to have agreed that any method, theory, or principle of regulation employed in arriving at this Stipulation is appropriate for resolving any issue in any other proceeding. No findings of fact or conclusions of law other than those stated in this Stipulation may be deemed to be implicit in this Stipulation.

(e) Each of the Parties reserves the right to respond in oral argument, file testimony, or pursue such course of action as it as it deems appropriate on any CCDS issue not covered by this Stipulation or on any other matter in this proceeding.

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(f) The Parties have negotiated this Stipulation as an integrated document. The Parties recommend that the Commission adopt this Stipulation in its entirety.

DATED: February 21, 2003

Northwest Natural Gas Company

By: Gregg S. Kantor
Its: Senior Vice President, Public & Regulatory Affairs

Northwest Industrial Gas Users

By: Chad Stokes
Its: Attorney

Coos County

By:
Its: County Commissioner

By:
Its: County Commissioner

By:
Its: County Commissioner

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UG 152/CUB/100
Jenks/1

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

UG 152

In the Matter of Northwest Natural Gas Company's Application for a General Rate Revision	)))	Testimony of the Citizens' Utility Board of Oregon on Coos County Pipeline Costs

I am Bob Jenks, Executive Director of the Citizens' Utility Board of Oregon (CUB). My qualifications are set out in Exhibit 101.

I. Introduction.

NW Natural's request to include in revenue requirement the Coos County distribution system asks too much of the Commission while at the same time provides too little from which the Commission must make its decision.

First, NW Natural's request to the Commission is incomplete. By asking the Commission to address revenue requirement without addressing allocation of that revenue requirement, the Company undercuts the necessary process of setting "fair and reasonable *rates*." Second, the Company fails to make its case that the Commission should ignore current regulatory policies in order to allow NW Natural to make uneconomic, subsidized investments for the primary purpose of economic development. The Company does not provide the evidence or justification necessary to depart from established policy or to place the expansion in rates at all. Third, the Company's case to justify the Coos County line is seriously deficient. The Company's forecast study and the identification of costs are unsupported or unsupportable.

Rather than setting terrible precedent by ignoring working policies and creating a new policy of ad hoc decision-making, we should attempt to address particular problems by focusing on the particular circumstances within the context of existing policy.

The Company fails to show why the Commission should overturn traditional ratemaking for this project. So the Commission should look to its traditional ratemaking approaches to determine how to treat this project. First the Commission should protect customers from paying for a project that harms them, i.e. provides a "negative benefit." This can be best done by applying the line extension policy in this case. However, recognizing that the citizens of Coos County may have difficulty paying their share of the line extension policy before the project is built, CUB is willing to consider a method to help Coos County.

II. Establishment of fair and reasonable rates requires the setting of revenue requirement and allocation of costs.

NW Natural provided half a filing in this phase of UG 152. There are two parts to ratemaking: deciding whether a Company can get recovery of certain costs and deciding which set of customers should pay those costs. In this phase of the case, NW Natural is asking the Commission to decide that the Company is allowed recovery of certain costs, but to punt on a decision over who pays those costs for several months.

It is inappropriate to do what NW Natural asks. The fundamental requirement for Commission decision-making is to obtain "adequate service at fair and reasonable rates." By asking the Commission to make a revenue requirement decision without allocating it to customers, the Company departs from the obligation to undergo traditional scrutiny to

establish fair and reasonable *rates*.

While the Company might argue that the rate implications are small enough that it is doubtful that a full decision would not be "fair and reasonable," this is not correct. We don't know the rate impact without knowing how the Commission is allocating these costs. Just as importantly, the law requires that rates be *fair, not that rate impacts be small*.

The Company is asking the Commission to include in revenue requirement costs that are not economic and are being incurred to serve a significant volume of industrial load. But the Company is not asking industrial customers to share in the costs of this service. This raises a fundamental question of *fairness*. However, the NW Natural proposal attempts to hide this very issue. By not allocating the increase in the first phase, there is not an issue of fairness to judge.

Finally, this raises questions of process and rationality. It is impossible to appeal the Coos County distribution system revenue requirement decision based on a claim that the Commission has established rates that are not fair and reasonable, because rates have not been set. Moreover, no set of customers can claim to be harmed by the decision, since the costs may later be allocated to a different set of customers. After the final order in the second phase of the case allocating costs, a party could ask for reconsideration of the rate spread in that case, but it will be too late to challenge the decision to include Coos Bay costs in revenue requirement. Because ratemaking is a combination of revenue requirement and allocating that revenue requirement to create rates, an appeal or reconsideration of a rate decision must be allowed to explore both the

revenue requirement and the allocation and the connection between the two.

For these reasons, CUB opposes NW Natural's proposal to disassociate the revenue requirement from the rate spread. CUB agreed to allow the Coos Bay distribution system to be on a separate phase and to be considered separately from the rest of the rate case, but we believe that this requires full ratemaking for those costs.

III. A Review of NW Natural's case.

Simply stated, the Coos County distribution system, as proposed, is an economic development program subsidized by existing NW Natural customers. Traditionally, rates would not be increased for an economic development program, but NW Natural is asking the Commission to ignore the economic development aspects of the program that is driving these costs.

A utility ought to have a compelling case in order to convince the Commission to override traditional policy. But Northwest Natural offers little evidence and a weak case. The Company offers 16 pages of testimony along with 7 exhibits. An examination of this testimony and exhibits reveals that it contains critical flaws:

- Nowhere in its testimony does the Company make a reasonable attempt to fully identify the costs that this investment will require from the customers of NW Natural. By ignoring the costs associated with the required "aggressive marketing effort," and the cost of the required special contract discounts, NW Natural's testimony oversells the benefits of the investment.
- All of the revenue assumptions are based on load forecasts from a

marketing study that is overly optimistic. The Company fails to provide the analysis and assumptions that drive the marketing study. By discounting the overly optimistic study (based on NW Natural's own "study" which is not included in the record) NW Natural is admitting that the marketing study is flawed. Even with the discount, the assumptions are too optimistic.

- By asking that the Commission approve rolling in all costs associated with this project, the Company is placing residential and small commercial customers at risk for this project. If its costs are higher, if demand is lower, it is residential and commercial customers who bear this risk. The Company fails to provide any real discussion of these risks, or why it is appropriate for these risks to fall on its residential and small commercial customers.

The Company begins its case by saying that the testimony would do four things:

1. Provide background on the project;

2. Descibe the research the Company conducted and its projections of load;

3. Describe the rate treatment of the project; and

4. Discuss the application of the Company's line extension and other relevant economic policies.

A. Background on the project. NW Natural describes the background, including the legislature's approval of $20 million in lottery funds to cover part of the cost of a pipeline from Roseburg to the Coast, the Coos County residents approving a maximum $27

million bond to pay for the rest of the cost of that pipeline, and the Transportation agreement that NW Natural signed with Coos County which requires NW Natural to construct a distribution system, serve customers and provide transportation services for industrial customers who buy directly from the County.

This background, however, makes clear that the purpose is industrial economic development. The legislature's approval of lottery funds was because "the pipeline will enable Coos County to attract significant industries to locate in the area, thereby increasing opportunities for employment and additional economic activities that well be generated as a result of such industries." NWN/1500/p2. The transportation agreement with Coos County also makes clear that the purpose is economic development:

> "The parties acknowledge that one purpose of Coos County's Pipeline construction is to attract businesses to Coos County that will utilize natural gas in industrial operations. Accordingly, as outlined in this Article 8, the parties will cooperate to encourage industrial gas customers to locate in Coos County and to contract with NW Natural for gas distribution."
>
> NWN/1501/23.

Article 8 of the agreement goes on to require that NW Natural offer special contracts to new industrial customers. NWN/1501/24. This project is clearly economic development and while that may be an appropriate action for the legislature and an appropriate use of lottery dollars, this Commission does not have statutory authority to engage in economic development by imposing a "tax" on existing residential and small commercial customers to pay for the Coos Bay system.

NW Natural suggests that because the legislature allocated $20 million in lottery funds, that ratepayers outside of Coos County should also pay millions of dollars. But we

read the legislature's decision differently. We believe that the Legislature allocated the amount of money that the State was willing to pay to support the Coos Bay project. The customers of NW Natural, outside of Coos County, are part of the State of Oregon and have made their contribution through the allocation by the Legislature.

The transportation agreement with Coos County is notable for several reasons. It requires that NW Natural "shall spend at least $1 million in marketing gas service in Coos County generally." NWN/1501/9. This is the only reference in this case to the cost to NW Natural for marketing.

B. The research the Company conducted and its projections of load.

The Company presents several studies that project load on the new system. Load projections are critical in this case because they will tell us if the Coos County project is economically viable to begin with, and will tell us the size of the subsidy coming from existing customers. If the load projections are too optimistic and the actual load does not meet the projections, then the revenue assumed does not materialize and the cost to existing customers increases.

Mr. Henderson's summarizes these studies (NWN/1500/6-8) and includes them as a Forefront Economics study and update (NWN/1502 and NWN/1505), an ECONorthwest study (NWN/1503) and a summary load projection from NW Natural (NWN/1504). The ECONorthwest study simply uses the Forefront Economics study as an input in calculating benefits from constructing, operating and using the distribution system, but made no attempt to verify the load projections. NW Natural's summary load projection is based on its "own research in 1999 [where] the Company adjusted Forefront Economics' low scenario forecast downward by 30 to 70 percent."

NWN/1500/7.

The Company does not believe that the marketing studies included as Exhibits 1502, 1503, and 1505 are a good basis for projecting load. This leaves us with their own summary projection, Exhibit 1504. The Company says its projection is based on its own study of initial customer loads. However, the Company did not include its study in its testimony. The Company did not include its methodology. The Company did not include the study's assumptions. All it included was a one page summary of its study. NWN/1504. The Company's testimony and exhibits include the studies the Company rejected, but fails to include the one study that was actually used.

In addition, the Company's projection (Exhibit 1504) includes Bandon as if it were part of the planned distribution system. NWN/1500/7. But Bandon is not included in the actual distribution system, so, in the words of the Company "load for the actual distribution system would be somewhat lower" than the Company's projections. NWN/1500/7. It is unclear why the Company did not updated its load forecast to exclude Bandon, but we are left with a record that does not contain an accurate projection of load.

According to the Forefront Economics study, in 1998 Bandon represented approximately 11% of the single-family households. NWN/1502/9. Failure to remove those households from the Company's study overestimates usage by 11%. However, the impact of not removing Bandon from the Company's projections is even greater. Bandon is growing at an annual rate of 3%, which is 10 times faster than the remaining communities (0.3%). CUB Exhibit 102. Because new houses are much more likely to use gas than existing homes, not correcting its study to remove the growth of new homes in Bandon increasingly overstates demand throughout the 20-year projections.

It is necessary to test the Company's load projections. Because there is little growth expected in the communities that NW Natural will serve and rental housing is unlikely to convert to natural gas, the primary residential market for natural gas will be existing single-family, owner-occupied homes.

We know that in 1998 there were 14,953 single family homes in Coos Bay, Coquille, Myrtle Point and North Bend and that this figure is growing by 0.3%/year. NWN/1502/9. CUB Exhibit 103 shows the percentage of these homes that NW Natural is projecting will be served by gas in the next few years. Northwest Natural assumes that 7% will get service in the first year and 29% will get service by the 5th year.

Year	Northwest Natural's Market Share Projections for SF homes
1	7%
2	12%
3	18%
4	23%
5	28%

Is it realistic to expect that nearly 30% of all owner-occupied homes in this area will convert to natural gas in the next five years? CUB believes that common sense and analysis tell us that this is wildly optimistic.

Converting to natural gas is expensive. This docket is only about the backbone distribution system. That backbone does not get gas to people's homes. If you look at the maps provided in the Company's testimony, they show a backbone distribution system through the commercial and industrial centers of these communities, which does not deliver service on most streets where residential customers live. NWN/1501/33-37.

The Company is building a pipeline to the North Spit where some future industrial customer might locate and might desire to gas service, but it is not building a pipeline down the residential streets where people currently live. The Company's line extension policy (the Company assumes the Commission will apply the line extension policy at this point) will require that residential customers make a significant investment to hook up to the backbone that in most cases is blocks away. In addition, to convert, customers must invest in their on-premises equipment -- replacing their furnaces, hot water heaters and any other appliances that they wish to run off gas.

Currently gas prices are near record highs and the gas futures market is suggesting that the near-record high prices will be around for a while. While the cost of oil heat is also climbing, there currently is little incentive to switch from heating oil to natural gas. Electricity customers currently have electric heat provided by PacifiCorp's coal and hydro system that is likely to see relatively stable rates for the next few years.

Finally, this is a community that is not doing well economically. Unemployment is high. Incomes are relatively low. Where will customers get the money to convert to gas?

There are several elements to the residential market. First, NW Natural assumes that few multifamily and rental residences will convert initially, leaving single-family owner-occupied residents as the primary market. There are several elements to this market:

1. Propane-heated homes. These homes should be the easiest to get to convert. Natural gas has significant economic advantages over propane. And because propane homes will not need new ductwork or a great deal of new equipment, the change will not

be prohibitively expensive assuming that customers can afford the line extension costs. This represents 7% of the homes in the county. CUB Exhibit 104. Even if the Company gets all of these homes in the next five years, they must also get ¼ of all other homes.

2. Heating oil. Heating oil homes will convert at a much slower rate. While oil heated homes have central furnaces and ductwork, there is little current price advantage to oil heat. According to the Office of Energy $1.39 per gallon heating oil is the same cost per MMBtu as $1.00 per therm gas. Oil heat customers primary incentive to switch is not cost savings, but problems with underground storage tanks and the convenience of not having to order heating oil. Because these customers will require the expense of line extensions and furnace work, and will see little economic benefit, it is doubtful that conversions from oil heat will happen at a rapid pace. There is some evidence to suggest that over time as people have to repair and replace furnaces and underground storage tanks that there will be conversions, but it will happen slowly. Oil heat homes make up another 13% of the homes in the area. If between furnaces breaking and leaking storage tanks the Company got 5% of these per year (all in 20 years) this would still leave the Company with a total market share of 11% after 5 years, less than half of what the Company is projecting.

3. Electric heat. There are clear price advantages to gas over electricity, though new models of heat pumps will work well in Coos Bay and allow customers to get some of the advantages of more efficient heating systems without paying for the cost of line extensions. Electric heat customers make up 56% of the homes. However, many existing electric heat homes do not have ductwork -they use baseboard or ceiling heat – and installing ductwork requires a systematic remodeling of an entire home. While

natural gas would likely replace electricity in new homes, few new homes are being built in this area. Natural gas might save these folks money in the long run, but between new duct work, the sunk cost of existing furnaces, and the cost of the line extension, the short term costs of conversion would be too high for a significant number to convert quickly.

4. Wood. We are left with the households that currently use woodstoves as their source of heat. With gas prices rising, there is no evidence that we have seen to suggest that these customers will save money converting. It is also unclear what alternatives these folks already have but are not currently using. If they have electric heat, but use wood as a cheaper alternative (which is probably most likely considering that electricity is the primary fuel for home heating in the area), then they have all the barriers of other electric heated homes. Because of the cost of conversion and the fact that they already have wood as an alternative, it is doubtful that many will pay the money for conversion.

The load forecast was an assumed fact in DR 30 and was not subject to scrutiny in that case. Because the projected revenues from this system depend on load, this load forecast deserves serious investigation. As offered in its testimony, the Company's studies are insufficiently supported and contain unrealistic conclusions. NW Natural's claim that this system will eventually pay for itself is based on these studies.

If the Commission accepts NW Natural's proposal and rolls these costs into normal revenue requirement, then the existing customers are on the hook for the costs. If the "expected" load does not show up, we pay even more. Because the Company controls when rate cases are filed and the Company can ask for a deferred account between ratecases for discrete cost items, customers are the ones taking the risk for this project and the risk that loads will not be as great as projected.

C. *The rate treatment of the project.*

Mr. Henderson describes the rate treatment for this project in pages 8 to 12 of his testimony. He begins by stating that NW Natural will incur three types of cost: construction, ongoing operations and maintenance expense, and the costs for gas transportation. His testimony does not mention the costs associated with marketing the gas, which the Company promised the County would be at least $1 million or the costs associated with special contracts that the Company has pledged to negotiate. NWN/1501/9 and NWN/1501/24.

1. The Cost of Construction. The cost of construction is estimated at $12 million. According to the Company:

> "NW Natural requests that the investment in the initial Coos County distribution system be included in rates effective with its in-service date, which we project will occur during the test period. The Commission staff has agreed to conduct a continuing audit of the project to ensure that only the actual, prudently incurred costs are included in rates. Once the initial distribution system is in service and the staff has completed its audit, NW Natural will ask the Commission to approve a special tariff schedule placing the costs in rates. Based on the estimated $12 million construction cost, the cost-of-service for this investment will add approximately $1.4 million per year to the Company's revenue requirement." NWN/1500/9.

The $12 million is only an estimate. The Company is asking for pre-approval from the Commission for all prudently-incurred costs of the project without actually knowing the real costs. Typically a utility that invests in a new capital project would absorb the costs of that project between the in-service date and the end of the next rate case. However, in this case Northwest Natural wants approval in advance so it can immediately place the costs in rates with a special tariff once the project is in service and

avoid the risk of regulatory lag. Customers are taking all the risks associated with this project. Why should the Company earn a return on equity for this project, if shareholders take almost no risk?

The Company's proposal creates significant problems. Assuming a construction cost of $12 million, NW Natural's presentation shows at best a marginal benefit. (Our analysis below shows that costs outweigh the benefits). If the Company wins pre-approval now, but the project ends up costing $15 million, the Commission does not get to revisit the analysis and decide that at $15 million, the project is not economic and turn it down. Instead the Company would get the entire $15 million. Customers could still try to show that the cost overruns were due to imprudent actions taken by the Company, but both customers and the Commission could no longer revisit the underlying benefit issue.

The Company is also including the cost of a pipeline connecting the Coos Bay/North Bend system to the North Spit, which is located on a peninsula west of Coos Bay. Currently there are no customers for the system on the North Spit. This is an area that the County is interested in for economic development reasons. If there are no customers for that section of the pipeline when it is completed, then the "used and useful principle" prevents it from being included in rates. According to the Transportation agreement with the County, the rate for an industrial customer locating on the North Spit will be based on the "lowest reasonably estimated bypass rate for connecting to the Pipeline." NWn/1501/26. In other words, residential and small commercial customers are being asked to pay for a pipeline to the North Spit specifically so a new industrial customer can "threaten" to bypass that pipeline and get a lower rate than is normally allowed, ensuring that residential and commercial customers continue to pay for this

industrial pipeline even when it is used and useful.

2. The Cost of Operation and Maintenance. The operations and maintenance costs are not described in Mr. Henderson testimony, nor detailed in his exhibits, beyond NWN/ 1506/1, which lists them at $418,000. The only discussion in testimony is a minimalistic description of this cost:

> "The forecast for Coos Bay O&M expense is $418,000. This amount will cover normal district office expenses, including customer acquisition, customers service, meter reading, and system integrity." NWN/200/8.

It is not clear if "customer acquisition" includes the marketing costs. The Forefront study talked about "aggressive marketing." NWN/1502/14. The transportation agreement with the County requires the Company during the first five years to spend $1 million on marketing. NWN/1501/9. NW Natural's testimony on marketing suggests that they plan to increase their marketing costs by $260,000 from 2001. NWN/600/8. Is this due to Coos County? Does the $418,000 for O & M include marketing costs or not? The testimony does not sufficiently enlighten us. The Company never explains how the marketing costs will be incorporated.

3. Transportation Costs. The Company is proposing to limit Coos County customers' transportation charge to 1 cent per therm, arguing that any amount above this will be a disincentive to those customers to convert to gas. NWN/1500/10. (To put this in perspective, the Company also argues that charging existing customers 1/3rd this amount to subsidize this project is so small as to be insignificant.) Transportation costs above this will be absorbed by the remaining customers, through the annual PCA mechanism.

4. Other Costs. The Company does not mention the costs of special contracts.

Under the transportation agreement with the County, new industrial load is eligible for special contracts. This will reduce the revenue from these customers. NW Natural claims that the Coos County project "is unlikely to earn its rate of return until approximately the twelfth year of service." NWN/1500/15. Does this analysis include the cost of special contracts discounts? Special contracts are typically offered to customers who have competitive alternatives. A special contract is supposed to make some contribution to distribution costs, but a lower one than under the tariffed rated. We cannot tell if the Company included these discounts in their model for this project.

The following is a more complete listing of the charges that the will fall on existing residential and small commercial customers of NW Natural as a result of this project:

*The projected cost of the pipeline.

*Any cost overruns.

*Costs (reduced revenues) from any shortfall on load projections.

*Transportation costs that are not covered by the $0.01/therm surcharge.

*O&M costs of the Coos County system.

*Marketing costs.

*Special contract discounts.

D. The Company's line extension and other relevant economic policies.

The Company argues that its line extension policy is not applicable in this case. Mr. Henderson argues that the Coos County service territory is unique because of the state and locally funded transmission pipeline, and that the proposal is "economically sound." NWN/1500/14. While the Company may consider the proposal economically

sound on the basis of what is proposed in this case, the proposal places the risks onto the residential and commercial customers. As we will show in the next section, based on what we know and don't know, the investment is not economically sound. If the pipeline costs more than projected, if the loads are lower then projected, if more marketing costs are included and if industrial discounts are taken into account then the project is not economically sound.

Which brings us back to the line extension policy. The reason we have a line extension policy, as articulated by Company witness Dr. John Hanson, is to ensure that growth is profitable. The policy protects existing customers from uneconomic investment. Under that policy the contribution from existing customers is fixed. If there are cost overruns, or load does not materialize, then existing customers are not left with their wallets exposed. The Company's rolled-in approach by design reverses this policy and places all the risk onto existing customers.

Mr. Henderson fails to make any mention of how the line extension policy protects existing customers or why it is appropriate to change policy and place all the risk on residential and small commercial customers. NW Natural has completely failed to carry the argument that standing policy to protect existing ratepayers should be thrown out.

IV. CUB's Conclusions.

A. Purpose is economic development.

An examination of this proposal makes clear that the real purpose is economic development. However the Public Utility Commission is not an economic development

agency and does not have authority to set economic development rates or create subsidies for the purpose of economic development. We have already discussed some of this in our review of the Company's proposal:

> *The legislature clearly was pursuing economic development when it made the decision to commit state funds to this project.*
>
> *The transportation agreement clearly states that a goal is economic development.*
>
> *The pipeline to the North Spit, which is part of the proposed distribution system, leads to no existing customer and has no purpose other than economic development.*
>
> *The requirement in the transportation agreement that NW Natural provide new industrial customers with special contracts is clearly part of the County's economic development strategy.*
>
> *The study by ECONorthwest (Exhibit 1503) shows that the motivation behind this is economic development.*

The ECONorthwest study is not just a clue as to the motivation behind the investment in the distribution system, but shows that the distribution system investment will create real, tangible and significant economic development results. Coos County would receive benefits far and beyond the cost of their bond and the cost of the Company's line extension policy:

> *Construction of the pipeline will add $6.9 million to personal income in the local community.*
>
> *Construction of the distribution system will contribute 95 person-years of employment and $2.3 million in personal income to the local community.*
>
> *The availability of natural gas for industrial development will provide a benefit of $1.6 billion in personal income and $253 million in business income over the next 20 years.*
>
> *Lower energy costs will save businesses $3.4 million over the next 20 years.*

*Coos County will receive an additional $79.3 million in prop*erty taxes.
NWN/1503/2-3.

These are laudable economic goals for Coos County, but there is no justification for why a subset of Oregon residents and businesses outside of Coos County, i.e. customers of NW Natural, should subsidize this county's business plan through utility rates.

The Company is asking the Commission to do something extraordinary. Normally a natural gas utility in Oregon would not make an uneconomic investment in a distribution system. Northwest Natural refers to this as "profitable growth":

> "Ratepayer benefits can be produced by growth if customer growth adds more to revenue than to the cost of serving new customers. This is the case for NW Natural. NW Natual has managed growth over a decade so that it is beneficial to both shareholders and ratepayers. Our growth policies are contained in our Main Extention tariff. Customers receive the benefits of profitable growth whether or not a general rate case is filled. Effectively, profitable growth allows an LDC to absorb cost increases or margin revenue losses without the need for formal rate relief."
> NWN/600/11

Traditionally, the Coos County distribution system investment would be covered by the Company's line extension policy. But this investment is not profitable growth, therefore a ratecase is required in order to ensure that the costs of this unprofitable growth fall on existing customers. So, in order to allow it to make an investment in "unprofitable growth" and because NW Natural would not normally be allowed to make investments that do not provide a net benefit, the Company is asking that the Commission ignore the line extension policy. This investment fails to provide net benefits to the system. Under traditional ratemaking it should not be allowed.

B. Are there customer benefits?

The real question that needs to be asked is do existing customers of NW Natural who are being asked to pay for this investment receive a benefit? Customers should not be made to pay for utility costs that provide a harm or no benefit to the utility system.

This is often referred to as the net benefits analysis. Ironically the net benefits analysis began with natural gas. When gas utilities were switching from manufactured gas to natural gas, commissions began evaluating the new investments in natural gas based on whether they provided a net benefit to customers. This is the same situation we find ourselves in today. Does the cost of bringing natural gas to Coos County provide a net benefit to NW Natural customers?

Even NW Natural argues that this is an appropriate test for adding new customers to the system generally: "In simple terms, the 'net ratepayer benefits' test is an evaluation of the financial performance of NW Natural's investments in new customers." NWN/600/Hanson/ 9.

However, NW Natural fails to apply this test to its investment in new customers in Coos County. Why? Because this investment cannot pass a net benefits test. Instead, NW Natural devises a new test of whether an investment is economic:

> "Q: Will the expansion of service into Coos County be economically sound?
>
> A: Yes, based on the proposal we are presenting in this case. Roll-in is necessary because we expect the customer base in Coos County to grow relatively slowly, so that the system is unlikely to earn its rate of return until approximately the twelfth year of service."

This answer says nothing about whether the project is economically sound, it only states a rate basing truth. Rate base and return on rate base are

front-loaded. In the first 12 years of an item being in rate base customers pay substantially more than they do in the next 12 years. CUB Exhibit 105 provides an example of a $20 million investment that will be rate based over 20 years. The costs of the plant are collected at $1 million per year with the Company earning a 9.5% rate of return on the unamortized plant. To ratepayers the total cost of the plant over 20 years is $38.05 million. However, the cost to customers in the first 12 years is $27.4 million. During the first half of the plants life, customers pay more than 62% of the costs associated with rate basing that plant.

For the Company to say that after 12 years the revenues will be greater than the costs is based on an accounting reality, but it is not a reasonable description of an "economic" investment. Even so, it is probably not accurate. It is based on unrealistic assumptions about load in the County, it does not seem to include the $1 million commitment to marketing and it does not include the cost of the special contract discounts the Company has committed to providing new industrial load in Coos County.

The reason the Company does not give a straight answer to the question of the whether this project is "economically sound" is that the Company knows that this project is not. In answering data requests in DR 30, the Company admitted that the project even over the next 30 years is a loser, would not provide benefits and would require a subsidy from existing customers:

> "Over a 30-year horizon, the difference between Coos Bay revenue requirement and the revenues generated by Coos Bay customers would lead to a levelized Oregon rate impact of about $.00049 cent per therm."
> CUB Exhibit 106.

This number may sound small, but the point is significant. First, the calculation is

based on the assumptions of costs and revenues that are optimistic. Second, it assumes that all customer classes are paying for the subsidy, when in fact the Company is asking that only residential and small commercial customers pay for the subsidy. Finally, a 30-year levelized per therm cost hides the real number. That number can be seen in CUB Exhibit 107.

The net present value for total revenue requirement is $29.9 million. The net present value for Coos Bay revenues is $ 23.7 million. The subsidy necessary for this project is $6.2 million.

Remember the Company stated that ratepayer benefits come from growth "if customer growth adds more to revenue than to the cost of serving customers." NWN/600/11. In this case the answer is growth in Coos County adds more costs than revenues.

In order to invest $12 million to build a Coos Bay distribution system, NW Natural is asking for a $6 million subsidy from residential and small commercial customers. Of course, because existing customers are taking the risk, the costs could be higher and/or the Coos Bay revenues could be lower, and therefore the subsidy could be higher. The Company must have meant that this project is economically sound for shareholders. Existing customers will not only subsidize Coos County customers, by enlarging NW Natural's service territory and rate based assets, existing customers are funding additional benefits for shareholders.

V. CUB's proposals.

A. *CUB's proposal for rate treatment.*

1. Transportation Costs.

NW Natural is proposing that Coos County customers receive a surcharge of $0.01 per therm to pay for transportation on the County's pipeline which NW Natural says "is NW Natural's cost of transportation on the County pipeline." NWN/1500/11. However, because the contract with the County has minimum charges that NW Natural will have to pay even if the load in Coos County is not high enough to cover the transportation costs, NW Natural is proposing that the existing customers pay this fee through a surcharge added to the normal PGA mechanism. The Company attempts to minimize this by stating that the:

> effect of statewide demand charges is extremely small. Even if the total possible transportation costs (approximately $200,000 per year) were included, the effect on rates would amount to only 0.00031 cents per therm.
>
> NWN/1500/12

The effect may be small, but why should customers who are not using the Coos County pipeline be paying transportation charges for that pipeline at all. The Company's answer is that if they were to charge Coos County customers more than $0.01 per therm, "it would threaten the viability of the entire project." NWN/1500/12. However, the Company offers no evidence to support this statement.

The Purchased Gas Adjustment mechanism is an annual rate change that exists because the variations in the cost of gas from one year to the next is too great a risk for the Company. The Company is now trying to use this mechanism to place a small risk associated with this project onto its residential and small

commercial customers. The shareholders want to earn their ROE on this investment but do not want to take any risk – even a risk whose maximum exposure is $200,000!

CUB could see a way to have the customers of NW Natural help pay for the costs of the pipeline that the Company will build (see next section). But we will not support charging non-Coos County customers O&M costs relating to a pipeline that is owned by the County. We agree the cost is relatively small, but believe that it is unfair for the shareholders of NW Natural to ask customers to bear the entire risk of all aspects of this project. This cost should be denied outright. The Company then has several options:

*it can raise the surcharge for County customers,

*it can ask the County to renegotiate these costs,

*or recognizing that the return on ratebase that shareholder will receive from this project are many times greater than this cost, and it can absorb these costs until demand grows on the system.

2. Distribution Pipeline Costs.

When considering how to allocate the costs of the pipeline, it is important first to identify what costs we are talking about. The Company's testimony is based on a pipeline that costs $12 million, but that is only an estimate. If the Commission approves adding pipeline costs into rates it must specify the amount that is being considered. The Company made the decision to seek pre-approval of the cost of the pipeline in order to avoid the normal regulatory lag between a Company making an investment and the Commission issuing an order allowing it in rates. This significantly reduces risk to the Company. However, in doing so the Company cannot be allowed to turn approval of the

project into a blank check, for costs above $12 million. Seeking pre-approval to avoid the risk of regulatory lag, creates a new risk of cost overruns that make the costs of the project greater than the pre-approval. If the Commission believes that this investment is reasonable at $12 million, that decision cannot mean that the Commission believes the investment is reasonable at $15 million. At $15 million, the Commission might find the entire project to be unreasonable. The Company has offered no evidence to support a cost above $12 million. The Commission should state clearly that any approval is limited to the costs that the Company filed in this case and the Company takes the risk for any costs above that amount.

Secondly, the Commission has to make a decision as to the North Spit pipeline. There is real doubt as to whether that section will be used and useful when completed. Ratemaking principles require that investments be used and useful before being added to rates. Oregon law requires that new investments be "presently used to serve customers" before they are added to rates. Any order from the Commission should clarify that the North Spit pipeline will not be added to rates until the Company can demonstrate that it is used and useful.

The Company argues in this case that its line extension policy is what ensures that new growth is profitable and provides a net ratepayer benefit. We agree. That is why we believe that it is the appropriate model for how to recover costs in this docket.

Under the line extension policy, the contribution from the Company (or existing customers in this case) is equal to the expected net revenues for the first five years of operation. In the case of the $12 million Coos Bay distribution system, this contribution from existing customers would be approximately $6 million. (This figure was arrived at

in DR 30.) The County (or its industrial, commercial and residential customers) would have to come up with the other $6 million. This works out well, since as we stated above, the expected subsidy under the Company's proposal is $6.2 million, so using the line extension policy will eliminate that subsidy.

We recognize that asking individual customers to pay for this before hooking up to the system becomes difficult. However, one option is to have the County pay this amount. Coos County voters authorized bonds for $27 million to pay for the County's share of the transportation pipeline, but the actual costs are expected to be $18 million. NWN/1500/14. This suggests that County residents are willing to spend an additional $9 million in order to receive natural gas service. The ECONorthwest study showed that the economic benefits to the County over the next two decades are nearly $2 billion. Asking County residents who stand to receive substantial benefits to share an additional $6 million in costs is much more sensible than asking remaining ratepayers, who receive no benefit to pay these costs.

However, if the County is unwilling to do so, we are willing to consider an agreement where the existing customers pay these costs, but are repaid over time by Coos County customers. CUB attempted to calculate what it would take for Coos County customers to pay back this amount over a 20-year period, but found the information on the record in this case was so flimsy that we could not complete the analysis. The forecasts the Company has included on the record in this case and DR 30 vary widely, particularly when it comes to industrial demand. (One forecast predicted 1 million therms of industrial load, another forecast predicted 19 million therms.) But we do believe that the concept ought to be workable. During the first 7 years all customers

would pay the costs of the distribution system as Northwest Natural proposes. Coos County customers, however, would pay an addition surcharge (possibly a combination of a customer surcharge and a per therm surcharge). The Coos County surcharge would go to pay back the non-Coos County customers for the $6 million in costs that is Coos County's share under the line extension policy.

B. CUB's proposal for rate spread.

The Company has proposed that the entire cost of this investment be placed on residential and commercial customers. This is unfair.

The purpose of the pipeline is industrial economic development. The transportation agreement that Northwest Natural signed with the County makes clear that NW Natural is building this distribution pipeline so the County can use it to recruit new industrial customers, who will be given special contracts.

In addition, the pipeline is designed to go through the commercial and industrial parts of the communities, but there will still be a significant investment required to bring natural gas service to residential customers. The Company proposes that residential customers pay for the extensions needed to bring gas from this backbone to their neighborhoods through the Company's line extension policy.

The Company's projections for residential demand on this pipeline are overly optimistic. Even the Company seems to agree that the real purpose is to serve commercial and industrial customers:

> "the state's and county's purpose in bringing gas to the regions is to strengthen the local economy, and NW Natural sees potential for industrial and commercial load growth, in particular, once the distribution infrastructure is in place."

NWN/1500/15.

The Company's proposal to make residential and commercial customers pay for a project that is designed primarily to serve commercial and industrial load seems like a cynical attempt to get industrial customers to support the pipeline. And why should they not. They get commitments for special contracts, they get gas service, and someone else pays all the development costs.

This will be defended by pointing to the Company's Long Run Incremental Cost study (LRIC) in UG 152. This should not be used as the basis to allocate the costs of this pipeline for several reasons:

- The LRIC study has yet to be reviewed.
- This pipeline has nothing to do with the long run incremental cost of service for residential or industrial customers in Portland or Eugene. These costs are a direct subsidy that has nothing to do with the cost of serving the existing customers.
- The reason we use LRIC to help allocate some costs is that LRIC is related to the cost of service in a competitive industry. If the price of a product is above LRIC and there are no barriers to entry, new providers will enter that market, sell the product and drive the price to LRIC. The scrutiny of the PUC is supposed to substitute for the market discipline. Because all customers groups including residential customers are above LRIC, the Commission has failed to provide this discipline and all customers are paying rates that are above what the market would allow.
- In an actual market, these pipeline would not be built if it required such a

subsidy. Market discipline would drive the price to LRIC and no provider would be allowed to add the cost of uneconomic investments to rates that are already above LRIC.

- The Company's admits that its LRIC study should not be the sole element in determining cost allocation, that the "results must be applied with caution." UG/152/1300/4.
- Even when using LRIC, good cost allocation says that costs that can be demonstrated to be caused by a specific rate class should be allocated to that rate class.

Ideally we would apply these costs between customer classes based on the projected load for that class. This keeps with the principle of cost causality. The problem is that the Company's load projections are not accurate enough to be sufficient as a basis to allocate these costs. Therefore CUB proposes that costs be allocated on an equal cents per therm basis.

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ENVIRONMENT

Contractor loses suit over Coos County gas pipeline

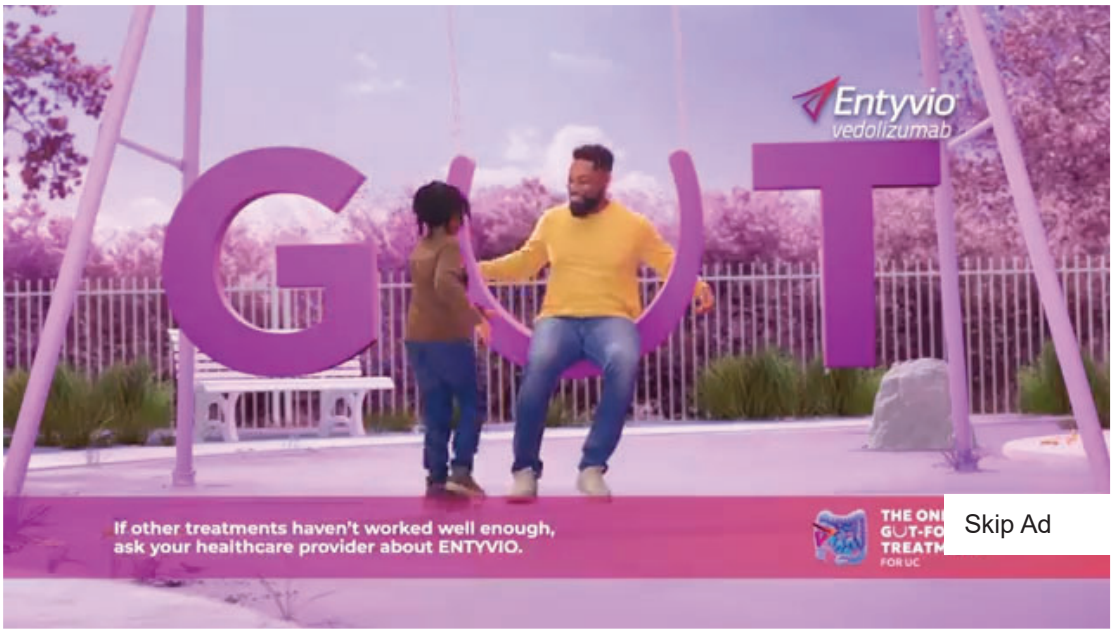
Published: Feb. 24, 2009, 1:40 p.m.

By Dylan Rivera, The Oregonian

MasTec Inc., the contractor fired not long after being hired to build a natural gas pipeline from Roseburg to Coquille, has been ordered to pay $1.5 million in penalties to the U.S. Treasury because of damage caused to pristine streams and rivers.

U.S. District Judge Michael Hogan issued the order despite finding that government agencies provided inadequate oversight of the $51 million project. And though the contractor violated the Clean Water Act, the judge said there did not appear to be serious environmental harm.

A MasTec attorney declined comment when reached by The Register-Guard newspaper Monday.



The project was dogged with problems since the summer of 2003, when work began on the 60-mile long, 12-inch pipeline. Crews filled streambeds with drilling spoils, threatening fish habitat. Regulators later discovered that project managers had not taken adequate steps to protect hillsides from erosion, leading to more sediment in fish spawning habitat.

Coos County terminated its contract with the Coral Gables, Fla.-based company in April 2004, and an Oregon firm finished the project later that year.

Until the project was completed, Coos County held the distinction as the largest county in the United States without natural gas service.

Coos County spent $35 million to build the pipeline over terrain that contractors described as some of the most rugged in the West. The line follows the old Wagon Road from Lookingglass near Roseburg west over the mountains through dense forest and under 188 streams.

Residents and environmental groups complained early and often about the project, contending that the state Department of Environmental Quality, the U.S. Army Corps of Engineers and Coos County were lax in their oversight of a project that crossed sensitive terrain, including dozens of parcels of private property.

Officials initially maintained that the project was on track and that state and federal clean water laws were being followed. But cost overruns and damage to pristine streams and rivers plagued the taxpayer-funded project.

The Oregon Department of Environmental Quality fined MasTec $205,000, then settled for $63,000. MasTec and the county sued each other in a case settled last year. The firm agreed to pay Coos County $8.7 million and dismiss its claims against the county, which totaled $14.5 million.

Then the Sierra Club, along with other environmental groups, filed suit in the case Hogan has now ruled on.

The $1.5 million fine fell well short of the amount sought by the plaintiffs. Their case was based in part on assertions that the company had saved $6 million by avoiding its Clean Water Act obligations. Hogan, however, wrote that MasTec lost $9.23 million on the project.

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The lack of government oversight was another factor Hogan used in determining the size of the penalty. "In this case, there was a failure of all parties concerned," wrote Hogan, who grew up in Myrtle Point, south of Coquille.

MasTec is a leading communications and energy infrastructure builder. For decades the company grew under the leadership of Jorge Mas Canosa, regarded as the most powerful and politically influential Cuban exile in the United States and head of the Cuban American National Foundation.

Jorge Mas Jr. is chairman of the board of the company, whose stock is traded on the New York Stock Exchange, where shares were at $9.25 this morning, up 22 cents from Monday's closing price.

-- The Associated Press and staff reports.

Dylan Rivera

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https://theworldlink.com/news/local/county-to-pay-final-penalties-on-natural-gas-pipeline-claims/article_62c86f8e-21dd-5b1d-9454-cb3f44eb9ebd.html

County to pay final penalties on natural gas pipeline claims

By Jolene Guzman, Staff Writer
Mar 19, 2008

COQUILLE — The Coos County Board of Commissioners approved and signed an agreement last Wednesday resolving claims of Clean Water Act violations against the county stemming from the 2003 construction of the natural gas pipeline from Coos Bay to Roseburg. In September 2003, The U.S. Army Corps of Engineers had filed suit against both the county and MasTec Inc., the Miami-based firm hired to build the pipeline.

A memorandum of understanding addressing the pipeline was signed by the county and the Corps in September 2004, but it has taken until now for the county to see a final agreement, Chairman John Griffith said. The county is the first to give its stamp of approval to the agreement. The U.S. Department of Justice has yet to sign, Commissioner Nikki Whitty added.

The agreement calls for payment of a $75,000 fine and restoration of sections of rivers and streams affected by pipeline construction.

Much of the restoration work has already been done, Griffith said. The 2004 agreement stated the county would spend $525,000 on restoration and fish passage improvements.

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“There isn’t very much (left),” Whitty said. “There might be seven or eight spots where we think the work is done, and the Corps isn’t sure.”

What remains is payment of the civil penalty. The county will transfer funds to the United States Department of Justice account in three $25,000 payments, the first of which will be paid within 30 days of signing the agreement. The remaining two will be paid on June 30, 2009; and June, 30, 2010.

Whitty said she is happy with the agreement, given the county could have been on the hook for a much larger amount.

Griffith was not of the same opinion. He said he voted against the memorandum of understanding in 2004 because the penalty was too severe.

“I thought it was excessive, because we hadn’t done anything wrong,” he said, adding that each time the Corps and the county sat down to negotiate, the requirements of the county were reduced. “We had them coming our way.”

This agreement doesn’t spell the end of lawsuits for the county, which still has to settle differences with MasTec, Griffith said.

In 2004, MasTec and the county exchanged lawsuits. MasTec drew first blood in February, in a $9.8 million suit, citing the county’s failure to pay for work. In April of that year, the county terminated its contract with the company and, in May counter-sued for $10 million, citing breach of contract. That lawsuit was later upgraded to $14 million.

Both lawsuits are now being addressed in settlement negotiations, Whitty said.

The county awarded the $23.3 million contract in June 2003 with completion expected by Dec. 31, 2003. A series of lawsuits against both MasTec and the county filled the following months. In October 2003, four county residents sued MasTec for $500,000, claiming damage to water pumps and creeks during underground drilling. Later that year, the Sierra Club, filed a $4.3 million suit against Coos County and MasTec, claiming environmental damage.

Along with the memorandum of understanding between the county and the Corps, claims brought by the Sierra Club, Klamath-Siskiyou Wildlands Project and the Coos County Coalition were settled in September 2004. The first lawsuit was settled in August 2004.

The county hired Oregon-based firm Rockford Corp. to finish the project in the summer of 2004. The finished pipeline started delivering to Coos Bay residents and businesses in January 2005.

So far, the pipeline has cost around $53 million, which is about $10 million more than the projected cost at the beginning of the project, Whitty said. She added the final cost will depend on the outcome of negotiations with MasTec.

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https://theworldlink.com/news/local/residents-file-pipeline-suit-against-coos-county/article_3ad55c23-e8fb-5b9a-87c9-0cec8f9430a7.html

Residents file pipeline suit against Coos County

By Amy Moss Strong, Staff Writer
Dec 10, 2003

A lawsuit filed late Monday in federal court is charging that Coos County and MasTec Inc. have violated the federal Clean Water Act by allowing illegal discharges in streams, during construction of a 60-mile natural gas pipeline being built from Roseburg to Coos Bay.

The plaintiffs, including local residents and environmental groups, are seeking more than $4.3 million in fines and civil penalties.

This is the second lawsuit filed against MasTec over pipeline issues. The first one was filed in Coos County Circuit Court in October by several citizens with properties along the pipeline route. They asked that more than $500,000 be awarded in personal damages for discharges on their properties. MasTec has not responded to that lawsuit, according to Brent Foster, a Portland lawyer working with Thane Tienson of Landye, Bennett and Blumstein, which filed both lawsuits.

Foster filed the lawsuit on behalf of the Sierra Club and the Klamath-Siskiyou Wildlands Project and the Coos County Coalition, a community group formed to address what it perceived as problems with the pipeline project.

Named as defendants in the lawsuit are MasTec, the Florida company installing the pipeline; Coos County; Coos County Commissioners Nikki Whitty, Gordon Ross and John Griffith; and Clark Besack, MasTec's project manager.

The lawsuit claims that, while drilling underneath stream beds, MasTec employees caused the ground to fracture and drilling lubricants to ooze into at least five local streams, including Rock Creek, Cherry Creek, Middle Creek, Wilson Creek and the North Fork of the Coquille River.

Those "frac-outs" have occurred for at least 157 days of the project, the lawsuit asserts. The plaintiffs are asking for $27,500 a day in civil penalties, that the directional drilling stop until the proper permits are obtained and that plaintiffs' legal fees be paid.

In addition, the plaintiffs are calling on MasTec and Coos County to take immediate steps to address perceived water pollution problems due to erosion along the pipeline project.

"What MasTec has done in Coos County is absolutely unconscionable," said Del Knight, a Myrtle Point resident and former logger who is president of the Coos County Coalition.

"Many of us would not have imagined being on the same side of an issue as the Sierra Club," Knight said, "but this is about our water and neither the county nor the Oregon Department of Environmental Quality have been willing to stand up to MasTec."

Foster described the situation as extreme, alleging MasTec and the county have "ignored the most basic water pollution laws we have and devastated critical habitat for salmon and polluted people's water supplies as a result," he said.

Commissioner John Griffith disagreed.

"It's unfortunate," Griffith said after reading the lawsuit Tuesday afternoon. "When the county designed the project, it chose to directionally drill streams 30 feet wide or under as an extra measure of environmental protection."

According to Griffith, typical pipeline construction consists of damming and trenching in streams. The county didn't choose that method because it wanted a pipeline that would be held to a higher standard, he said.

"I guess no good deed goes unpunished," he added. "We on the board are not happy that there was any discharge at all into those streams that were directionally drilled. The idea of going under the streams was to avoid that, so we're unhappy, too."

Jay Waldron, the county's lawyer handling pipeline issues, said he had not yet read the complaint.

"When I do, I'll be happy to talk about it," Waldron said.

Commissioners Nikki Whitty and Gordon Ross and MasTec's Clark Besack were unavailable for comment.

The state court lawsuit is about getting compensation and relief by those people who allege their water supplies were damaged as a result of MasTec activities, Foster said.

"This federal lawsuit is about the most fundamental aspects of the Clean Water Act, which is that you're not allowed to discharge without a permit and there was no permit to allow the frac-outs," he said.

Foster added that the DEQ issued a notice of non-compliance and the Army Corps of Engineers issued cease and desist orders to MasTec prior to the filing of the first lawsuit.

"The big thing that neither of these agencies did is force (MasTec) to stop, which they could have easily done through a court order," Foster said.

Besack, as project manager for MasTec, is directly responsible for overseeing the directional drilling, the lawsuit claims, and was aware of the problems. In addition, the lawsuit contends that both the county and the Board of Commissioners have been aware of the discharges and have allowed drilling to continue.

Work on the pipeline has slowed and plans are to take it up again in January, although MasTec spokesman Jack Beebe said Monday that final cleanup might not be complete until spring.

That has the plaintiffs' worried.

"There is a compelling need for MasTec to immediately install the basic erosion control measures as they said they would," said Breanna Bell, an attorney with the Klamath-Siskiyou Wildlands Project.

Randy Knop, a union representative who works with the pipeline industry, said he sees the suit as a necessary step.

Knop said in his opinion, the bottom line is that MasTec is giving the entire pipeline industry and pipeline workers a bad name and they need to be held accountable.

Steve Oxford, county pipeline adviser with Industrial Gas said in an interview Monday that he feels the citizen group has a hidden agenda. Rather than helping with problems, the group has delayed work into the rainy months, he said.

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Rates & Regulatory Affairs

ADV 1789

NW NATURAL ADVICE NO. 25-23 SCHEDULE 160 TSA COOS COUNTY

Data Request Response

Request No.: ADV 1789 OPUC IR 5

With construction overheads included, what does the Company estimate Pipeline landslide mitigation costs to be?

Response:

With construction overheads included, the Company estimates Coos County Pipeline landslide mitigation costs to be roughly $13.20 million to $14.70 million.

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Rates & Regulatory Affairs

UG 527

NW Natural Alternative Rate Mechanism

Data Request Response

Request No.: UG 527 CUB DR 20

Has Coos County or the Company approached or been approached by any other entities for taking ownership of the pipeline? If so, please provide a narrative explanation for why those proposals were not deemed acceptable.

Response:

No, the Company has not approached or been approached by any other entities regarding interest in taking ownership of the Coos County Pipeline.

Regarding Coos County being approached or approaching other entities: The Company is not aware of Coos County approaching or being approached by other entities regarding interest in taking ownership of the Pipeline.

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Rates & Regulatory Affairs
UG 527
NW Natural Alternative Rate Mechanism
Data Request Response

Request No.: UG 527 OPUC DR 47

Please provide an estimate of the proportion of the Company's rate base that is made up of investments that were made to address identified imminent safety risks.

Response:

After the Company explained to Staff the challenges of estimating the proportion of safety-related capital identified in rate base, Staff suggested that the Company provide narrative examples of safety-related projects from the past throughout its system, including the size of the projects.

a. Safety Project Plans

Each year, the Company performs safety-related activities all throughout the Company's Oregon service territory.

In compliance with the Public Utility Commission of Oregon's Order No. 17-084 in Docket UM 1722, the Company has annually filed a Safety Project Plan ("SPP") since 2017 with the OPUC. The purpose of the annual SPP is to demonstrate NW Natural's commitment to safety, to provide insight into NW Natural's safety activities, and to identify when major regulatory changes may drive new safety program priorities or modify existing safety programs.

Each SPP filing includes updated capital and O&M safety projects for the next calendar year in the Company's Oregon service territory.

Each of the Company's SPP filings describes the Company's historical capital expenditures related to safety projects in Oregon. Historical capital expenditures related to safety projects include:

i. Repairs and replacements due to excavation damages.
ii. Repairs and replacements due to pipe material, weld or joint failures.
iii. Repairs and replacements due to corrosion.
iv. Repairs and replacements due to leakage.
v. Replacements of pipelines with vintage pipeline materials such as bare steel.

vi. Work to remove and replace non-piggable fittings on transmission pipelines to accept inline inspection devices (only the first project to make the pipeline piggable is capitalized).
vii. Work to perform transmission pipeline material verification, where records are missing.
viii. Work to re-pressure test transmission pipelines with missing hydrotest records.
ix. Distribution Integrity Management Plan (DIMP) Accelerated Action programs such as vintage plastic material replacements, guard post installations, and proactive excess flow valve (EFV) installations.
x. Work to rework underground storage wells and perform well integrity assessments (only the first assessment is capitalized).
xi. Replacements of pipelines due to natural forces threats, such as landslides, flooding, erosion, or riverbed scouring.
xii. Development of transmission integrity management risk models and distribution integrity management risk models.
xiii. Company participation in a Public Awareness program.

Also described in the Company's annual SPP filings are the Company's planned capital safety project investments for the upcoming year in Oregon. Section 6.7 of the Company's annual SPP filings lists the Company's historical capital expenditures related to safety-related projects since 2015. Section 7 of the Company's annual SPP filings describes the forecasted O&M expenses for the upcoming year for safety-related activities in the state of Oregon.

i. Please refer to UG 527 OPUC DR 47 Attachment 1 for the 2026 SPP.
ii. Please refer to UG 527 OPUC DR 47 Attachment 2 for the 2025 SPP.
iii. Please refer to UG 527 OPUC DR 47 Attachment 3 for the 2024 SPP.
iv. Please refer to UG 527 OPUC DR 47 Attachment 4 for the 2023 SPP.
v. Please refer to UG 527 OPUC DR 47 Attachment 5 for the 2022 SPP.

b. Misc. Safety Projects

The Company performed numerous safety-related capital projects between 2005 and 2019 throughout the Company's Oregon service territory. Please refer to UG 527 OPUC DR 47 Attachment 6.

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September 25, 2025

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attention: Filing Center
201 High Street SE Suite 100
PO Box 1088
Salem, Oregon 97308-1088

Re: UM 1900: NW Natural's 2026 Oregon Safety Project Plan in Compliance with Order No. 17-084

Northwest Natural Gas Company, dba NW Natural (NW Natural or Company), hereby submits its 2026 Safety Project Plan in compliance with Commission Order No. 17-084 entered March 6, 2017.

Please address correspondence on this matter to me with copies to the following:

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Sincerely,

/s/ Rebecca Trujillo

Rebecca Trujillo
Regulatory Consultant

Enclosure

NW Natural®

2026 SAFETY PROJECT PLAN

OREGON

September 25, 2025

250 SW Taylor Street
Portland, Oregon 97204
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1 Introduction

In compliance with the Oregon Public Utility Commission ("Commission" or "OPUC") Order No. 17-084 ("Order") in Docket UM 1722, this Safety Project Plan ("SPP") outlines NW Natural's safety project investments for 2026. The SPP includes updated capital and O&M projects and programs and projects that carry over from 2025.

This SPP demonstrates NW Natural's commitment to pipeline safety by providing insight into NW Natural's safety activities and identifies NW Natural's response to regulatory changes that may drive safety program priorities or modify existing programs. In the future if NW Natural seeks approval for a Safety Cost Recovery Mechanism (SCRM), this SPP is intended to expedite the review process of safety investments.

Safety is a core value at NW Natural and we appreciate the opportunity to present this information to the Commission.

2 Background Information

NW Natural is a regulated natural gas utility conducting business in Oregon and southwest Washington. The Company serves ~802,000 customers and owns and operates ~660 miles of natural gas transmission pipeline, and ~14,500 miles of distribution pipelines. In addition, NW Natural operates three energy storage facilities in Oregon – Portland and Newport LNG Plants and Mist Underground Storage.

NW Natural's pipelines and storage facilities are governed by the following sections of the Code of Federal Regulations (CFR):

- 49 CFR Part 192 – Minimum Safety Standard – Transmission & Distribution Systems
- 49 CFR Part 193 – LNG Safety Standards
- 49 CFR Part 196 – Protection of Underground Pipelines from Excavations Activity
- Additional OARs (OAR 860-024 – Safety, OAR 860-031 – Pipeline Inspections), and ORSs such as ORS 757.039 – Regulation of hazardous substance distribution and storage operations, and ORS 757.542-993 – One call notification. -

In addition to the federal and state regulations identified above, NW Natural's safety program considers the findings of past Oregon legislative actions directing the Oregon Seismic Safety Policy Advisory Commission to prepare the Oregon Resiliency Plan. Consequently, the Oregon Resilience Plan Implementation Task Force issued a report recommending that the Commission require regulated energy providers to conduct seismic assessments of regulated facilities and allow cost recovery for prudent investments related to assessments and mitigation of vulnerabilities identified during those assessments.

The State of Oregon has since continued to advance resiliency planning efforts, including the "Resiliency 2025" plan. A key strategy of the plan is to improve the energy

infrastructure to prevent and mitigate catastrophic failure and ensure fuel supplies and alternate energy sources are available to responders and the public.

3 Threat Identification

NW Natural's four highest ranking threats, as identified in the DIMP (Distribution Integrity Management Program) Plan are:

3.1 Excavation Damage

Excavation damage continues to be the principal threat to NW Natural's gas distribution system, comprising approximately 86 percent of all recorded leak repairs. Excavation damage is a system-wide threat brought on predominantly by improper excavation practices. NW Natural's efforts to reduce excavation damages are described below.

3.1.1 Excavation Training and Education:

NW Natural actively engages in training and education for contractors, general public, and other utilities, to promote safe excavation procedures and practices. These efforts include classes on Oregon dig laws, displays at public events, and the use of media including print, radio, television, and internet to promote safety, best practices, and the use of 811.

NW Natural's Damage Prevention Department works to reduce the number of excavation damages through investigation, cause analysis, locate ticket risk modeling, and proactively works to identify and support contractors engaging in high-risk construction activity.

3.1.2 One-Call Notification Practices:

NW Natural actively participates in local and state-level Utility Coordinating Councils as well as the One Call Utility Notification board. A primary function of these organizations is to reduce damages to underground utilities through excavation best practices, public awareness, and the use of the Oregon One-call system (811).

NW Natural also maintains a robust Public Awareness Program based on the American Petroleum Institute (API) Recommended Practice (RP) 1162, which includes advertising, direct mailing, and public event outreach to increase awareness of One-call notification.

3.1.3 Locating Practices:

NW Natural is an active member of Oregon's One-call system and responds to all locate requests. Due to the high volume of locate requests this work is contracted. All locating is performed by qualified personnel and oversight is performed by Company contract management personnel. In addition, locating

activity is included in NW Natural's Quality Assurance program to minimize the incidences of errors, mismarks, and missed due dates.

3.1.4 Incorrect Facility Marking:

Incorrectly marked facilities may be due to underground interference, equipment issues, inaccurate facility maps, or procedural issues. Locating personnel responsible for a mismark receive additional training and are required to re-qualify prior to being allowed to locate gas facilities. Review of mismarks are conducted by supervisor or other qualified personnel and the results are used to identify deficiencies, correct facility maps, and ensure the facilities can be reliably located.

3.2 Material, Weld or Joint Failure

Material, weld, or joint failure is the second largest threat to the NW Natural gas distribution system, comprising approximately 9 percent of all recorded leak repairs. NW Natural is proactive in its efforts to reduce these occurrences, as described below.

3.2.1 Plastic Pipe Installed from 1960s to 1980s:

NW Natural makes every effort to identify all pre-1982 plastic pipe installations, analyze leak histories, evaluate any conditions that may threaten integrity of the pipe, and take appropriate remedial action, including replacement, to mitigate risks to public safety.

3.2.2 Plexco Service Tee Celcon Caps:

NW Natural is aware of industry issues regarding Plexco Service Tee Celcon Caps possibly leaking when over-tightened during installation. These caps exist within the gas distribution system and are replaced as found and scheduled for replacement when leaks are identified.

3.2.3 Polyethylene ("PE") Fusion Failure:

NW Natural has a robust training and Quality Assurance/Quality Control program in place to ensure proper PE fusion quality. This program includes testing, biannual qualification, and ongoing training. All PE fusions are visually inspected, and pressure tested prior to being placed in service.

3.2.4 Flat Back Risers:

In 2012 NW Natural identified a type of riser stop valve, internally known as a "Flat Back Riser," that contained components prone to atmospheric corrosion in the coastal areas of NW Natural's service territory. NW Natural identified that corrosion-related failure on a retaining pin could result in a hazardous leak. NW Natural developed an Accelerated Action Plan to replace these valves in coastal areas.

3.3 Equipment Failure

Equipment Failure is the third largest threat to the NW Natural gas distribution system, comprising approximately 1 percent of all recorded leak repairs. NW Natural's efforts to reduce these occurrences are described below.

3.3.1 Valves:

Valves are vital to the safe operation of a gas distribution system. NW Natural has in place a key operating valve inspection and maintenance program to ensure key valves are operable and available for use. Valves that are found to be inoperable, inaccessible, and/or paved over are identified and remediated as necessary.

3.3.2 Pressure Control / Relief Equipment:

NW Natural has an established inspection and maintenance program in place for pressure control/relief equipment to ensure reliable and safe operation.

3.3.3 Mechanical Couplings:

Pipe may pull out from compression couplings due to tensile forces including excavation damage, cyclic fatigue from changes in the temperature of natural gas as a result of the Joule-Thomson effect, ground movement from earthquakes or after heavy rains. Mechanical fitting failures are investigated, tracked, and reported per PHMSA and OPUC requirements.

In the past as an alternative to welding small diameter steel fittings, mechanical couplings were sometimes used to install valves and service tees. These types of fittings may develop leaks through the elastomer seal between the coupling and the pipe. NW Natural replaces these fittings with welded steel fittings or polyethylene as discovered during routine operations and maintenance activity.

3.3.4 Other:

Other types of material or equipment failure may occur in the gas distribution system. Failure reports are reviewed to detect trends or patterns that may affect the distribution system.

Many of the safety projects identified in this plan are in direct response to the above threats, and to maintain compliance with safety codes and regulations.

3.4 Corrosion

Corrosion is the fourth largest threat to the NW Natural's gas distribution system, comprising less than 1 percent of all recorded leak repairs. NW Natural's efforts to reduce these occurrences are described below.

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3.4.1 Pipe Replacement:

The driver of external corrosion system-wide is steel pipe. At this time NW Natural's distribution system in Oregon is 45 percent coated and cathodically protected steel and 55 percent polyethylene. During all pipe replacement projects consideration is given to replacing existing steel pipes, valves, and fittings with polyethylene to mitigate the threat of corrosion. In 2015 NW Natural completed the replacement of all known un-coated bare steel pipe eliminating the single largest corrosion threat.

3.4.2 Pipe Casings:

Steel casings are primarily used to protect or facilitate the installation of mains and services underground and are fitted with seals to prevent water intrusion, spacers to prevent contact between the casing and gas carrying pipe, and vents.

NW Natural inspects steel casings annually to identify problems such as contact between the casing and gas pipe, or water intrusion. If a "short" or other anomaly is identified a work order is created to address the concern.

At NW Natural the installation of casings has been largely replaced by HDD (Horizontal Directional Drilling) installation. During pipeline improvement projects existing casings are evaluated for replacement by HDD or alternatives.

3.4.3 Atmospheric Corrosion:

NW Natural's system includes facilities such as risers, regulators, station piping, bridge crossings and other above ground facilities that are susceptible to atmospheric corrosion.

NW Natural's atmospheric corrosion mitigation plan includes replacement of facilities when appropriate as well as protective coatings such as epoxies, paint, wax, other corrosion resistant materials, and enhanced inspections in locations with an elevated risk of corrosion.

3.4.4 Exposed Pipe Inspections

During normal operations when a buried pipeline is exposed crews inspect the pipe and protective coating for evidence of corrosion, or coating anomalies that can lead to future corrosion. Coating repairs or pipe replacements are completed before the pipe is backfilled and placed back in service.

4 Safety Activities Performed by NW Natural

Safety activities at NW Natural can be divided into categories:

4.1 Prescriptive Regulatory Actions – Includes actions which must be performed to meet minimum federal safety standards.

49 CFR 192 includes multiple prescriptive activities, intended to safeguard public safety, and fall into broad categories such as "operations" (Subpart L) and "maintenance" (Subpart M). Most of these activities require inspections at prescribed intervals to confirm that a facility or asset is meeting operational requirements prescribed by federal code. These activities provide the baseline data for other performance-based activities and include, but are not limited to:

- Atmospheric corrosion surveys
- Leakage surveys
- Cathodic protection surveys
- Right of way ("ROW") patrols
- Valve maintenance
- Water crossing inspections
- Odorization
- Odorometer Reads
- Line Marking
- Pressure Regulation Inspection
- Large Meter Inspections
- Record Keeping
- Control Room Management
- Bridgeline Inspections
- Equipment Calibration
- Houseboat Inspections

The safety activities from this category are prescriptive in nature and are not driven by risk analysis alone. Because these activities are required, they are not discussed further in this SPP, which instead focuses on projects and/or programs identified by NW Natural as essential to enhancing safety and reliability.

4.1.1 Transmission Integrity (TIMP)

Transmission Integrity refers to 49 CFR 192 Subpart O-Gas Transmission Pipeline Integrity Management. This federally mandated program covers natural gas transmission pipelines located in High Consequence ("HCA") and Moderate Consequence ("MCA") areas. NW Natural exceeds code requirements in TIMP to include pipelines and conditions outside of HCA and MCAs.

Activities in this category include baseline (initial) assessments and reassessments of transmission lines using in-line inspection ("ILI") and other direct assessment methods. They may also include pipeline replacements and

modifications in compliance with integrity management rules, best practices, and relocation of facilities to mitigate threats posed by natural forces such as flooding, land movement, and erosion.

4.2 Proactive, Performance-Based Actions

Other sections of 49 CFR 192 include more proactive performance-based risk reduction activities, such as Subpart P – Distribution Integrity Management Program ("DIMP"), Damage Prevention, and Public Awareness. These programs utilize a performance-based approach to mitigate risk and ensure that mitigation efforts are effective, drawing on operational experience and best practices.

4.2.1 Distribution Integrity (DIMP)

Distribution Integrity is outlined in 49 CFR 192 Subpart P- Gas Distribution Pipeline Integrity Management. This federally mandated program requires operators to create a written Distribution Integrity Management Program that takes into consideration: system knowledge, threat identification, evaluation and risk ranking, identification and implementation of measures to address risk, measurement of results, and reporting.

Activities in this category include projects warranting Accelerated Action ("AA") to address a system integrity risk. These AA projects are identified through risk modeling, industry identified threats, and by subject matter experts within the Company, and include:

- Replacement of vintage plastic services,
- Relocation of facilities under structures,
- Remediation of idle risers,
- Replacement of valves, fittings, and materials susceptible to leakage,
- Protection of above grade gas facilities,
- Crossbore investigation, and
- Relocation of distribution gas lines to mitigate threats posed by natural forces such as:
    - Flooding
    - Land movement, and
    - Erosion.
- Proactive EFV (Excess Flow Valve) Installation – installation of EFVs on services that were installed prior to the EFV rule issued in 2006.
- Dithiazine – a sulfur compound found in natural gas that has been known to cause equipment failure especially in district regulators.
- Valves separating MAOPs – These are single valves in the NW Natural distribution system that separate pipelines that operate at two different Maximum Allowable Operating Pressures (MAOPs). These valves present an Incorrect Operations threat because improper operation could allow pressure to equalize between the two systems, potentially creating an

overpressure condition. The Company is reviewing those installations and remediating areas where those valves have been installed.

- Ongoing assessment and relocation of meters inside of building to exteriors.

4.3 Safety Policy and Practices

NW Natural also implements risk reduction activities not explicitly required by the federal code. These actions have been identified as prudent safety practices intended to enhance public safety, improve system reliability, and maintain the safe operation of NW Natural's above and below-ground facilities including LNG Plants and underground natural gas storage facilities. These risk reduction actions include:

- Seismic vulnerability assessments of LNG Plants, the Mist Underground Storage Facility, and Transmission Pipeline System as recommended by SB 33 (2013) and consistent with the Governor's Resiliency 2025 Plan
- Accelerated replacement of vintage materials
- In line assessment of Transmission pipelines outside of high and moderate consequence areas.
- Development of a PSMS (Pipeline Safety Management System)
- Proactive EFV installation.
- Locate ticket risk modeling.
- Natural forces assessments of NW Natural's transmission system as part of NW Natural patrol and surveillance programs.
- Installation of guard posts and traffic barricades to protect above ground facilities from vehicular damage.

5 Projected and Preliminary Costs Presented in this Plan

The 2026 Capital and O&M costs presented in this plan are projected based on current expenditures for each of the identified projects through the end of the year. Costs presented for the significant safety initiatives are preliminary for planning purposes and do not include NW Natural overhead costs. Costs for safety projects under consideration will be presented in future SPPs.

6 2026 Capital Safety Investment

In 2026, NW Natural estimates it will invest $16.6 MM in capital to comply with DIMP, TIMP, and other regulations. Significant projects in this category include:

6.1 P09.06 & .07 St. Helens Trans (2025-26 estimate of $4.5MM)

This project involves the first inline inspection assessment of the 8-inch and 6-inch St. Helens Trans line which was primarily built in 1961 to support Scappoose and St. Helens. This pipeline is an approximately 12-mile transmission pipeline that initiates at the Sauvie Island Gate station and runs north through Sauvie Island and Scappoose. Inline assessment of this line will terminate at a location north of

Scappoose where the line transitions from 6-inch to 12-inch in diameter. Design work on this project will begin in 2025 with planned completion in 2026.

6.2 GP Wauna (2025-26 estimate of $1 MM):

During standard maintenance activities it was identified that the 8-inch transmission main that provides natural gas to the GP Wauna facility was located at a depth that did not meet current standards and was at risk due to ditch clearing activities that occur as the pipeline crosses US Highway 30. NW Natural has coordinated with the Operations department at GP Wauna to relocate a section of pipe to a proper depth while minimizing disruption at the GP Wauna facility. Work on this project is scheduled to begin in 2025 with planned completion in 2026.

6.3 Pro-active EFV Installations (2026 estimate of $1MM):

On October 14, 2016, the U.S. Department of Transportation's ("DOT's") Pipeline and Hazardous Materials Safety Administration ("PHMSA") adopted code requiring the installation of EFVs or shut-off valves on all new or replaced branched service lines (Docket No. PHMSA-2011-009). While the code requires EFV installation on all new or replaced branched service lines, it did not require retrofitting EFVs on existing services.

NW Natural believes a proactive EFV installation program is a prudent action that can mitigate the consequence of a gas release resulting from excavation damage to a gas service line. NW Natural is implementing a policy to retrofit EFVs on existing gas service lines when the buried portion of the service line is exposed, and the work involves the interruption of gas service.

This proactive EFV program was initiated in 2020 and will continue to be a safety program.

6.4 Sewer Crossbore Inspections (2026 estimate of $2.4MM):

The sewer crossbore program involves the visual inspection of sanitary sewers for incidences of gas line crossbores. In installations where trenchless technology was used to install polyethylene pipe, there exists the possibility the gas line was bored through a sewer main or lateral. NW Natural's policy is to expose all foreign line crossings when performing trenchless work. Sewer crossbores typically occur when facility owners fail to locate their pipe, creating a situation where NW Natural is unable to expose facilities during construction. This is an industry-wide threat. Although sewer crossbores are not isolated to gas operators, the consequence when gas lines are involved can be high. This program identifies existing trenchless polyethylene installations and inspects the sewers in the vicinity to identify crossbores. In addition to the field work for this program, NW Natural plans to implement risk modeling to better identify where sewer crossbores are located in the system. This risk modeling will use past data and industry information to

identify high-risk areas for sewer crossbores and allow crews to focus visual inspections in high-risk areas.

6.5 Underground Storage – Well Integrity (2026 estimate of $1.95MM)

On December 19, 2016, PHMSA issued an interim final rule (IFR) establishing regulations for underground natural gas storage facilities (UNGSF). The IFR incorporated by reference RP 1171, "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs" (First Edition, September 2015). The IFR implemented PHMSA's authority to regulate underground gas storage and the Congressional mandate in section 12 of the PIPES Act to establish minimum safety standards.

The final rule published on February 12, 2020, modified compliance timelines, clarified regulatory roles, reduced recordkeeping and reporting requirements, and formalized integrity management practices. In accordance with the final rule, NW Natural has completed baseline casing inspection logs on each of its active gas storage wells prior to the March 13, 2027, deadline.

Work in 2026 will involve the plug and abandonment of one gas storage well and the reassessment of the production casing of two gas storage wells.

6.6 Other safety projects and programs (2026 estimate of $1.5 MM):

Pipeline Replacement due to Seismic/Natural Forces

Portions of NW Natural's distribution and transmission system cross through landslide faults, seismic faults, sensitive areas, and waterways. Due to significant weather events or the passage of time, the integrity of these pipelines may be compromised. When identified during patrols, routine maintenance, or other stakeholders, the Integrity Team develops plans to remediate these at-risk pipelines as they are identified.

Valve Isolation Plans

NW Natural is working to develop a strategy for identifying and installing additional valves in the distribution system to assist in the isolation of portions of the distribution system in case of an emergency or third-party damage.

Meter Protection Installation

NW Natural will continue installation of guard posts adjacent to meter sets that are determined to be at risk of damage due to vehicle or equipment contact.

Pipeline Modification due to ROW Encroachment

Patrols of NW Natural Pipelines may discover structures or other encroachments built over or adjacent to pipelines that can impact the safe operation of or access to a pipeline. This program works with landowners to remediate these encroachments.

Pipeline Material Identification (PMI)
At selected transmission pipeline anomaly remediation sites, NW Natural has instituted a process using technology to non-destructively test and acquire data regarding pipe material properties. In addition, when the Transmission Integrity rule went into effect over twenty years ago, NW Natural began keeping short (18-inch-24-inch long) sections of pipe for future reference. These spools were destructively tested to obtain pipe material properties that were not required as part of the original installation documentation. The material data obtained through this program are being stored in the permanent record for each pipe segment.

Non-hazardous Leakage Projects
As part of NW Natural's continued efforts to reduce fugitive methane emissions, actions are being taken to proactively replace facilities identified as producing non-hazardous leaks. Per NW Natural Standard Practices these facilities are reevaluated and monitored on a routine basis until the leak classification changes or the facility is repaired or replaced. To address these frequent revaluations and reduce fugitive methane emissions a more proactive approach is being taken towards these facilities and projects are being developed to accelerate replacements.

Removal of Class A Services
NW Natural has performed work to eliminate a low-pressure system and transition to a full distribution system. During this transition to eliminate the low-pressure system a small number of Class A services still exist in the system. These Class A services have an MAOP of 12 inches of water column and are a legacy from the low-pressure system. NW Natural has initiated DIMP project to work with these customers to eliminate these Class A services from the system.

Idle Risers
Idle risers are the above ground portion of a service line that remains after meter removal when a customer closes their account, or a home or business is vacated. In these cases NW Natural maintains the service (idle) riser above ground where it is capped/plugged and tagged as idle. These idle risers are maintained in accordance with code requirements in the event a customer or a new tenant requests gas service. Over extended periods of time and in some instances these idle risers may present an elevated risk of damage. In 2025 NW Natural will develop a process to identify at-risk idle risers and begin development of a program to remove them and abandon the service line.

6.7 Historical Capital Expenditure – Safety Project Plan (System Integrity)

The Historical Capital Expenditures below are actual expenditures for each of the presented years.

Year	Expenditure
2015	$17,190,356*
2016	$ 7,772,763
2017	$ 5,925,409
2018	$ 9,699,814
2019	$10,231,431
2020	$ 8,900,000
2021	$ 8,200,000
2022	$ 9,000,000
2023	$13,000,000
2024	$14,500,000
2025	$18,300,000

*Final year of known bare steel main replacement

Historical capital expenditures include:

- Work to modify pipelines to accept inline inspection devices, including removal or replacement of non-piggable fittings and facilities required to launch and receive inline inspection devices.
- Pipeline relocation to mitigate threats including outside forces and natural forces. This work does not include relocations due to utility conflicts, or third-party improvement projects.
- Pipe replacements and testing in compliance with federal and state regulations.
- Ongoing DIMP AA programs/projects such as Vintage Plastic, Guard post installations, Proactive EFV installations, etc.

7 2026 O&M Expenditures

In 2026 NW Natural expects to spend $5.7MM in O&M to address and comply with DIMP, TIMP, damage prevention, and public awareness.

Activities that reflect expenditures in this category include costs for supplies (office/field), reference materials, education (conferences/workshops), vendor and contract costs associated with transmission assessments, public awareness program materials, advertisements and mailings, and natural forces investigation and remediation. Additionally, this category covers the development, initiation, and execution of studies and consulting fees related to integrity requirements, such as class location studies and third-party geotechnical site evaluations to address and mitigate risk.

O&M also includes some non-capital internal labor in support of NW Natural's system integrity program ("SIP"). These costs include the Integrity Management staff (7 FTE), damage prevention staff (4.5 FTE) involved in damage prevention/investigation, and a

public information officer for safety outreach, training, and program administration. The Integrity Management group may also utilize other internal resources in support of SIP activities which include GIS analysts, Customer Service, Construction, and other subject matter experts. Significant O&M projects include:

7.1 Transmission Inline and Direct Assessment Reassessment and Remediation (2026 estimate of $3.3MM):

This work includes the federally prescribed seven-year reassessment of transmission pipelines in HCAs and is comprised of both inline inspection and direct assessment of transmission assets and associated repairs.

7.2 Natural Forces (2026 estimate of $125,000):

Where the threat of natural forces can be mitigated without pipe replacement or rerouting, NW Natural may choose to address the threat through site work. This option is necessary in situations where a reroute is not feasible due to environmental restrictions or where a pipeline serves a critical customer or provides a single feed to a distribution system. Work may include armoring of slopes, re-grading of sites, culvert improvements, and retaining structures to address land movement and drainage issues.

7.3 Damage Prevention (2026 estimate of $1MM):

In compliance with DIMP regulations, and to address the single largest threat to gas facilities, NW Natural maintains a damage prevention department. The department consists of a supervisor and 4.5 FTE damage prevention specialists whose responsibilities include damage prevention through high risk locate ticket intervention, training, attendance at pre-construction meetings, participation in Utility Coordinating Councils, and support of the 811 One-call system. Damage prevention specialists are also responsible for the investigation, enforcement, and contractor training related to excavation and third-party damage.

7.4 Public Awareness (2026 estimate of $950,000):

NW Natural's Public Awareness program meets the requirements mandated in API RP 1162, adopted by reference by PHMSA into Part 192.616(a), (b), and (c). This program promotes public safety through communication and outreach focused on educating customers and the public about natural gas safety. The program includes customer correspondence, mailers, advertisements, community events, mobile phone applications, and brochures to excavators, contractors, public officials, residences and businesses along pipeline rights-of-way and in high consequence areas, and floating homes.

The Public Awareness Plan utilizes television and radio advertising, bill inserts, social media, and events to promote natural gas safety awareness. Targeted outreach and public awareness materials are provided annually to customers near transmission pipelines, as well as contractors, excavators, and first responders within NW Natural's service territory.

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7.5 Right-of-Way Encroachments (2026 estimate of $100,000):

Pipeline patrols are used to identify changes in site conditions. An example of such a change is the installation of structures over pipelines, and inside dedicated pipeline rights-of-way, or easements. In some instances, the remediation may involve the relocation of structures and other non-gas facilities.

7.6 Probabilistic Distribution Risk Model ($1.5MM between 2025 and 2030):

In 2023 NW Natural initiated a project to partner with a data analysis consultant to implement a Probabilistic Risk Model to assess the NW Natural distribution system. A probabilistic risk model is a model that determines the probability of failure in the system and quantifies the consequences of a failure per threat. Probabilistic Risk models have been identified by PHMSA as a best practice to proactively manage threats to the natural gas distribution system. This risk model is a 5-year program that began implementation in 2025.

7.7 Historical O&M Expenditure – Safety Project Plan (System Integrity):

The historical O&M expenditures below are actual expenditures for each of the presented years (not including PSMS, damage prevention or public awareness expenditures).

Year	Expenditure
2015	$4,034,218
2016	$4,889,618
2017	$4,771,267
2018	$4,000,000
2019	$3,052,000
2020	$3,100,000
2021	$2,900,000
2022	$2,800,000
2023	$3,000,000
2024	$ 700,000
2025	$3,300,000

Historical O&M expenditure included:

- Regulatory transmission assessments including the investigation and remediation of identified anomalies resulting from inline inspection and external corrosion direct assessment (ECDA).
- Investigation and remediation of natural forces including landslides, flooding, erosion, etc.
- Buildover remediation where structures encroach into pipeline right-of-way.
- Remediation of difficult to operate valves.
- Maintenance of Integrity Risk model as a result of geographical and system changes.

These above costs do not reflect those related to ongoing maintenance of facilities including right-of-way clearing, patrols, leakage, cathodic protection, and other ongoing routine O&M work.

8 2026 Significant Safety Initiatives

8.1 Changes in TIMP Assessment Methodology

In 2026, NW Natural will extend the use of inline inspection (ILI) for integrity assessment of transmission pipelines assessed at seven-year intervals. Inline inspection tools have the advantage over direct assessment and pressure testing because they assess the entire pipeline maintaining constant contact with the inner wall providing data allowing for the identification of interacting anomalies such as pipe deformation and metal loss. In 2026, NW Natural will change the assessment methodology of the following pipelines.

- P09.06 & .07 St. Helens Trans – Approximately 12-mile transmission pipeline that provides gas from Sauvie Island to Scappoose.

8.2 Pro-active EFV Installations

NW Natural has installed EFVs on all new single-family residential services since February of 1999. In 2006, the Federal Code was modified to require the installation of EFVs on all new residential and small commercial services. NW Natural will continue and expand the program installing EFVs on existing residential and small commercial services when the buried portion of the service line is exposed and service to the customer is interrupted. NW Natural believes proactive installation of EFVs is a prudent and pragmatic approach that can mitigate the consequence of excavation damage to a service line.

9 Transmission Material Verification

In compliance with recent Regulatory Mandates involving material verification of steel transmission pipelines, NW Natural has implemented a non-destructive material verification program to collect material property data on transmission pipeline assets. This program involves material testing of in-service pipelines during planned work to collect material data including metallurgy that was not required at the time of installation.

NW Natural has also developed a program to destructively test segments of pipeline that were removed from past transmission projects to collect the material property information. Collecting material information from the in-service transmission mains and the destructive tests from the historical transmission mains will allow NW Natural to develop a library of pipeline material property data.

10 Cost Benefit Analyses & Alternative Analysis

The performance of a cost benefit analysis and alternatives analysis is difficult in the context of safety programs mandated by regulation. As a result, a cost benefit analysis has not been a primary consideration in this report because these safety projects are mandated by CFR, dictated by industry best practices, or driven by operational requirements. The assigned risk and prioritization for implementing these projects are based on in-depth studies and analysis of NW Natural's transmission and distribution systems as well as plant and storage assets. Studies performed as part of normal operations provide measurable and continual feedback needed to perform safety related work for which there are few practicable alternatives.

Alternative analysis and in-depth studies are useful when they identify threats and risks that can be mitigated or eliminated through the application of performance-based best practices, engineering analysis, operational knowledge, and subject matter experts. Where the CFR prescribes compliance activity or mandate programs, the use of cost benefit, or alternative, analysis is not warranted.

When a pipeline safety initiative requires a cost benefit or alternative analysis, NW Natural may select a qualified external resource to perform the analysis.

11 Legislative Update

11.1 PHMSA Rulemaking Docket No. PHMSA-2011-0023;

Amendment No. 192-132 - RIN 2137-AF39 Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments. PHMSA published this rule on August 24, 2022. NW Natural is in compliance with the rule as published.

11.2 Docket No. PHSMA-2021-0039 Pipeline Safety NPRM: Gas Pipeline Leak Detection and Repair

On May 18, 2023, PHSMA issued a Notice of Proposed Rule Making: Gas Pipeline Leak Detection and Repair. The NPRM colloquially referred to as the LDAR rule is intended to reduce methane emissions from new and existing gas transmission and distribution pipelines, gas gathering pipelines, and underground natural gas storage facilities. NW Natural is reviewing the NPRM and will comply with the final rule when it is published in the Federal Register.

11.3 Docket No. PHSMA-2021-0046 Pipeline Safety NPRM: Safety of Gas Distribution Pipelines and Other Pipeline Safety Initiatives

On September 7, 2023, PHSMA issued a Notice of Proposed Rule Making: Safety of Gas Distribution Pipelines and Other Pipeline Safety Initiatives. PHMSA proposes revisions to the pipeline safety regulations to require operators of gas distribution

pipelines to update their distribution integrity management programs (DIMP), emergency response plans, operations and maintenance manuals, and other safety practices. These proposals implement provisions of the Leonel Rondon Pipeline Safety Act—part of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020. NW Natural is reviewing the NPRM and will comply with the final rule when it is published in the Federal Register.

12 Completed Projects

Below is the list of projects scheduled to be completed in 4th quarter of 2024 and 2025.

12.1 Underground Storage – Well Integrity ($1.1MM – Actual)

This project involved the re-work and reassessment of two wells in the Mist storage field. The 2025 project represents year eight of NW Natural's well integrity baseline assessment work that includes down hole assessment of production casing and replacement of select tubulars, downhole equipment, and wellhead components. The reassessments include a downhole assessment of production casing and replacement of select tubulars, downhole equipment, wellhead components, and/or mechanical integrity testing. The program was developed to meet compliance with PHMSA's adoption of APR RP 1171 - Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs. The reassessment intervals are determined by risk assessment and information from the baseline assessments. This project has been completed.

12.2 S03 Salem Bypass Trans ILI (~2025 actual $3.5M)

This project involves the first inline inspection assessment of the 8-inch Salem Bypass Trans line which was primarily built in 1958 to support north Salem and Keizer. This pipeline is an approximately 5.5-mile transmission pipeline that initiates at a station near the Marion St. Bridge in downtown Salem and runs north and east to a valve station at Hwy 99E and Blossom Rd. NE. Design work on this project started in 2024 with construction completed in the spring of 2025. Cleaning and inline assessment of this pipeline will start in the fall of 2025 with data analysis, remediation and repairs continuing into 2026.

12.3 Willis Creek (~ 2025 actual $4.7M):

This project involves the replacement of approximately 3700' of the P30 Central Coast Feeder east of Lincoln City, Oregon. This section of the P30 Central Coast Feeder is a 12-inch 600 psig MAOP pipeline that supports the communities in Lincoln County from Lincoln City to Newport. In the winter of 2021/2022 an inactive landslide identified in 2001 has become high risk landslide due to wildfires in the summer of 2020 followed by heavy rains which created a new landslide and increased the risk of an inactive landslide becoming reactivated. After review of the area it was determined that the pipe is at high risk and needed to be relocated. The project will involve a 2700' section installed using Horizontal Directional Drilling

(HDD) technology and 900’ section installed via direct bury to relocate the pipeline in a stable location. Project is anticipated to be completed in 2025.

12.4 Highway 212 (~2025 Actual $3.9M):

This project involves the relocation of approximately 2500 feet of 12-inch transmission main located on the south side of Hwy 212 in Clackamas. During routine pipeline patrols in 2023 it was discovered that increased flow in the Clackamas River adjacent to the 12-inch transmission main had caused erosion to the northern bank of the river near the pipeline. Further monitoring through the winter of 2023-24 resulted in an increased observation of this erosion that posed an increased risk to the pipeline such that relocation was recommended. Work on this project began in 2024 with planned completion in the fall of 2025.

12.5 Perrydale Weld Repairs (~2025 Actual $1.0M):

This project involves the discovery of existing welds at the Perrydale Regional Station that were discovered to have lack of penetration. These welds are located on a valve that separates MAOPs at this station and is subject to external forces due to the location near a highway. Due to the risk associated with these welds, the valve is going to be replaced and the station redesigned to eliminate the single valve between MAOPs.

13 Conclusion

This SPP provides an overview of NW Natural’s pipeline safety initiatives and commitment to the safe and reliable delivery of natural gas to the communities we serve. Through its more-than 165-year history, NW Natural has been committed to identifying threats to pipeline safety and taking steps to address and mitigate those threats. Looking forward to the role natural gas will play in our energy future, and as members of the communities we serve, NW Natural recognizes the trust placed on us by our neighbors and customers. NW Natural will continually work to ensure public safety and maintain the integrity of our natural gas system.

NW Natural®

250 SW Taylor Street
Portland, OR 97204

503-226-4211
nwnatural.com

September 23, 2024

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attention: Filing Center
201 High Street SE Suite 100
PO Box 1088
Salem, Oregon 97308-1088

Re: UM 1900: NW Natural's 2025 Annual Oregon Safety Project Plan in Compliance with Order No. 17-084

Northwest Natural Gas Company, dba NW Natural (NW Natural or Company), hereby submits its 2025 Safety Project Plan in compliance with Commission Order No. 17-084 entered March 6, 2017.

Please address correspondence on this matter to me with copies to the following:

eFiling
Rates & Regulatory Affairs
NW Natural
250 SW Taylor Street
Portland, Oregon 97204
Telephone: (503) 610-7330
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Sincerely,

/s/ Rebecca Trujillo

Rebecca Trujillo
Regulatory Consultant

Enclosure

NW Natural®

2025 SAFETY PROJECT PLAN

OREGON

September 23, 2024

250 SW Taylor Street
Portland, Oregon 97204
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NW Natural®

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1 Introduction

In compliance with the Oregon Public Utility Commission ("Commission" or "OPUC") Order No. 17-084 ("Order") in Docket UM 1722, this Safety Project Plan (SPP) outlines NW Natural's safety project investments for 2025. The SPP includes updated capital and O&M projects and programs and projects that carry over from 2024.

This SPP demonstrates NW Natural's commitment to pipeline safety by providing insight into NW Natural's safety activities and identifies NW Natural's response to regulatory changes that may drive safety program priorities or modify existing programs. In the future if NW Natural seeks approval for a Safety Cost Recovery Mechanism (SCRM), this SPP is intended to expedite the review process of safety investments.

Safety is a core value at NW Natural and we appreciate the opportunity to present this information to the Commission.

2 Background Information

NW Natural is a regulated natural gas utility conducting business in Oregon and southwest Washington. The Company serves ~790,000 customers and owns and operates ~660 miles of natural gas transmission pipeline, and ~14,400 miles of distribution pipelines. In addition, NW Natural operates three energy storage facilities in Oregon – Portland and Newport LNG Plants and Mist Underground Storage.

NW Natural's pipelines and storage facilities are governed by:

- 49 CFR Part 192 – Minimum Safety Standard – Transmission & Distribution Systems
- 49 CFR Part 193 – LNG Safety Standards
- 49 CFR Part 196 – Protection of Underground Pipelines from Excavations Activity
- Additional OARs (OAR 860-024 – Safety, OAR 860-031 – Pipeline Inspections), and ORSs such as ORS 757.039 – Regulation of hazardous substance distribution and storage operations, and ORS 757.542-993 – One call notification.

In addition to the federal and state regulations identified above, NW Natural's safety program considers the findings of Oregon House Resolution 3 (HR 3, 2011) which directed the Oregon Seismic Safety Policy Advisory Commission to prepare the Oregon Resiliency Plan with the purpose of identifying recommendations for how Oregon's critical energy infrastructures could be made seismically resilient against a Cascadia subduction zone earthquake. Upon completion of that work on February 28, 2013, the Oregon Senate passed Senate Bill 33 (SB 33, 2013), which established the Governor's Task Force on Oregon Resilience Plan ("ORP") Implementation ("Task Force"). In October 2014, the Task Force issued a report recommending that the Commission require regulated energy providers to conduct seismic assessments of regulated facilities and recommended that the Commission allow cost recovery for prudent investments related to assessments and mitigation of vulnerabilities identified during those assessments. In October 2018, Governor Kate Brown presented the "Resiliency 2025" plan,

titled “Improving Our Readiness for the Cascadia Earthquake and Tsunami” (“Resiliency 2025 Plan”). The Resiliency 2025 Plan follows the 2013 ORP and outlines six key strategies for the State of Oregon. Its vision is to “protect all Oregonians by ensuring we are prepared to survive and recover from the expected 9.0 magnitude Cascadia earthquake and ensuing tsunami.” The key strategy of the Resiliency 2025 Plan to improve the energy infrastructure is to “develop a plan for the Critical Energy Infrastructure Hub to prevent and mitigate catastrophic failure and ensure fuel supplies and alternate energy sources are available to responders and the public.”

3 Threat Identification

NW Natural’s four highest ranking threats, as identified in the DIMP (Distribution Integrity Management Program) Plan are:

3.1 Excavation Damage

Excavation damage continues to be the principal threat to NW Natural’s gas distribution system, comprising approximately 86 percent of all recorded leak repairs. Excavation damage is a system-wide threat brought on predominantly by improper excavation practices. NW Natural’s efforts to reduce excavation damages are described below.

3.1.1 Excavation Training and Education:

NW Natural actively engages in training and education for contractors, general public, and other utilities, to promote safe excavation procedures and practices. These efforts include classes on Oregon dig laws, displays at public events, and the use of media including print, radio, television, and internet to promote safety, best practices, and the use of 811.

NW Natural’s Damage Prevention Department works to reduce the number of excavation damages through investigation, cause analysis, and proactively works to identify and support contractors engaging in high-risk construction activity.

3.1.2 One-Call Notification Practices:

NW Natural actively participates in local and state-level Utility Coordinating Councils as well as the One Call Utility Notification board. A primary function of these organizations is to reduce damages to underground utilities through excavation best practices, public awareness, and the use of the Oregon one call system (811).

NW Natural also maintains a robust Public Awareness Program based on the American Petroleum Institute (API) Recommended Practice (RP) 1162, which includes advertising, direct mailing, and public event outreach to increase awareness of One-call notification.

3.1.3 Locating Practices:

NW Natural is an active member of Oregon’s one call system and responds to all locate requests. Due to the high volume of locate requests this work is contracted. All locating is performed by NW Natural qualified personnel and oversight is performed by Company

contract management personnel. In addition, locating activity is included in NW Natural's Quality Assurance program to minimize the incidences of errors, mismarks, and missed due dates.

3.1.4 Incorrect Facility Marking:

Incorrectly marked facilities may be due to underground interference, equipment issues, inaccurate facility maps, or procedural issues. Locating personnel responsible for a mismark receive additional training and are required to re-qualify prior to being allowed to locate gas facilities. Review of mismarks are conducted by supervisor or other qualified personnel and the results are used to identify deficiencies, correct facility maps, and ensure the facilities can be reliably located.

3.2 Material, Weld or Joint Failure

Material, weld, or joint failure is the second largest threat to the NW Natural gas distribution system, comprising approximately 9 percent of all recorded leak repairs. NW Natural is proactive in its efforts to reduce these occurrences, as described below.

3.2.1 Plastic Pipe Installed from 1960s to 1980s:

NW Natural makes every effort to identify all pre-1982 plastic pipe installations, analyze leak histories, evaluate any conditions that may threaten integrity of the pipe, and take appropriate remedial action, including replacement, to mitigate risks to public safety.

3.2.2 Plexco Service Tee Celcon Caps:

NW Natural is aware of industry issues regarding Plexco Service Tee Celcon Caps possibly leaking when over-tightened during installation. These caps exist within the gas distribution system and are replaced as found and scheduled for replacement when leaks are identified.

3.2.3 Polyethylene ("PE") Fusion Failure:

NW Natural has a robust training and Quality Assurance/Quality Control program in place to ensure proper PE fusion quality. This program includes testing, biannual qualification, and ongoing training. All PE fusions are visually inspected, and pressure tested prior to being placed in service.

3.2.4 Flat Back Risers:

In 2012 NW Natural identified a type of riser stop valve, internally known as a "Flat Back Riser," that contained components prone to atmospheric corrosion in the coastal areas of NW Natural's service territory. NW Natural identified that corrosion-related failure on a retaining pin could result in a hazardous leak. NW Natural developed an Accelerated Action Plan to replace these valves in coastal areas.

3.3 Equipment Failure

Equipment Failure is the third largest threat to the NW Natural gas distribution system, comprising approximately 1 percent of all recorded leak repairs. NW Natural's efforts to reduce these occurrences are described below.

3.3.1 Valves:

Valves are vital to the safe operation of a gas distribution system. NW Natural has in place a key operating valve inspection and maintenance program to ensure key valves are operable and available for use. Valves that are found to be inoperable, inaccessible, and/or paved over are identified and remediated as necessary.

3.3.2 Pressure Control / Relief Equipment:

NW Natural has an established inspection and maintenance program in place for pressure control/relief equipment to ensure reliable and safe operation.

3.3.3 Mechanical Couplings:

Pipe may pull out from compression couplings due to tensile forces including excavation damage, cyclic fatigue from changes in the temperature of natural gas as a result of the Joule-Thomson effect, ground movement from earthquakes or after heavy rains. Mechanical fitting failures are investigated, tracked, and reported per PHMSA and OPUC requirements.

In the past as an alternative to welding small diameter steel fittings, mechanical couplings were sometimes used to install valves and service tees. These types of fittings may develop leaks through the elastomer seal between the coupling and the pipe. NW Natural replaces these fittings with welded steel fittings or polyethylene as discovered during routine operations and maintenance activity.

3.3.4 Other:

Other types of material or equipment failure may occur in the gas distribution system. Failure reports are reviewed to detect trends or patterns that may affect the distribution system.

Many of the safety projects identified in this plan are in direct response to the above threats, and to maintain compliance with safety codes and regulations.

3.4 Corrosion

Corrosion is the fourth largest threat to the NW Natural's gas distribution system, comprising less than 1 percent of all recorded leak repairs. NW Natural's efforts to reduce these occurrences are described below.

3.4.1 Pipe Replacement:

The driver of external corrosion system-wide is steel pipe. At this time NW Natural's distribution system in Oregon is 49.8 percent coated and cathodically protected steel and 50.2 percent polyethylene. During all pipe replacement projects consideration is given to replacing existing steel pipes, valves, and fittings with polyethylene to mitigate the threat of corrosion. In 2015 NW Natural completed the replacement of all known un-coated bare steel pipe eliminating the single largest corrosion threat.

3.4.2 Pipe Casings:

Steel casings are primarily used to protect or facilitate the installation of mains and services underground and are fitted with seals to prevent water intrusion, spacers to prevent contact between the casing and gas carrying pipe, and vents.

NW Natural inspects steel casings annually to identify problems such as contact between the casing and gas pipe, or water intrusion. If a "short" or other anomaly is identified a work order is created to address the concern.

At NW Natural the installation of casings has been largely replaced by HDD (Horizontal Directional Drilling) installation. During pipeline improvement projects existing casings are evaluated for replacement by HDD or alternatives.

3.4.3 Atmospheric Corrosion:

NW Natural's system includes facilities such as risers, regulators, station piping, bridge crossings and other above ground facilities that are susceptible to atmospheric corrosion.

NW Natural's atmospheric corrosion mitigation plan includes replacement of facilities when appropriate as well as protective coatings such as epoxies, paint, wax, other corrosion resistant materials, and enhanced inspections in locations with an elevated risk of corrosion.

3.4.4 Exposed Pipe Inspections

During normal operations when a buried pipeline is exposed crews inspect the pipe and protective coating for evidence of corrosion, or coating anomalies that can lead to future corrosion. Coating repairs or pipe replacements are completed before the pipe is backfilled and placed back in service.

4 Safety Activities Performed by NW Natural

Safety activities at NW Natural can be divided into categories:

4.1 Prescriptive Regulatory Actions – Includes actions which must be performed to meet minimum federal safety standards.

49 CFR 192 includes multiple prescriptive activities, intended to safeguard public safety, and fall into broad categories such as "operations" (Subpart L) and "maintenance" (Subpart M). Most of these activities require inspections at prescribed intervals to confirm that a facility or asset is meeting operational requirements prescribed by federal code. These activities provide the baseline data for other performance-based activities and include, but are not limited to:

- Atmospheric corrosion surveys
- Leakage surveys
- Cathodic protection surveys
- Right of way ("ROW") patrols
- Valve maintenance
- Water crossing inspections
- Odorization
- Odorometer Reads
- Line Marking
- Pressure Regulation Inspection
- Large Meter Inspections
- Record Keeping
- Control Room Management
- Bridgeline Inspections
- Equipment Calibration
- Houseboat Inspections

The safety activities from this category are prescriptive in nature and are not driven by risk analysis alone. Because these activities are required, they are not discussed further in this SPP, which instead focuses on projects and/or programs identified by NW Natural as essential to enhancing safety and reliability.

4.1.1 Transmission Integrity (TIMP)

Transmission Integrity refers to 49 CFR 192 Subpart O-Gas Transmission Pipeline Integrity Management. This federally mandated program covers natural gas transmission pipelines located in High Consequence ("HCA") and Moderate Consequence ("MCA") areas. NW Natural exceeds code requirements in TIMP to include pipelines and conditions outside of HCA and MCAs.

Activities in this category include baseline (initial) assessments and reassessments of transmission lines using in-line inspection ("ILI") and other direct assessment methods.

They may also include pipeline replacements and modifications in compliance with integrity management rules, best practices, and relocation of facilities to mitigate threats posed by natural forces such as flooding, land movement, and erosion.

4.2 Proactive, Performance-Based Actions

Other sections of 49 CFR 192 include more proactive performance-based risk reduction activities, such as Subpart P – Distribution Integrity Management Program ("DIMP"), Damage Prevention, and Public Awareness. These programs utilize a performance-based approach to mitigate risk and ensure that mitigation efforts are effective, drawing on operational experience and best practices.

4.2.1 Distribution Integrity (DIMP)

Distribution Integrity is outlined in 49 CFR 192 Subpart P- Gas Distribution Pipeline Integrity Management. This federally mandated program requires operators to create a written Distribution Integrity Management Program that takes into consideration: system knowledge, threat identification, evaluation and risk ranking, identification and implementation of measures to address risk, measurement of results, and reporting.

Activities in this category include projects warranting Accelerated Action ("AA") to address a system integrity risk. These AA projects are identified through risk modeling, industry identified threats, and by subject matter experts within the Company, and include:

- Replacement of vintage plastic services,
- Relocation of facilities under structures,
- Remediation of idle risers,
- Replacement of valves, fittings, and materials susceptible to leakage,
- Protection of above grade gas facilities,
- Crossbore investigation, and
- Relocation of distribution gas lines to mitigate threats posed by natural forces such as:
  - Flooding
  - Land movement, and
  - Erosion.
- Enhanced EFV (Excess Flow Valve) Installation – installation of EFVs on services that were installed prior to the EFV rule issued in 2006.
- Dithiazine – a sulfur compound found in natural gas that has been known to cause equipment failure especially in district regulators.

4.3 Safety Policy and Practices

NW Natural also implements risk reduction activities not explicitly required by the federal code. These actions have been identified as prudent safety practices intended to enhance public safety, improve system reliability, and maintain the safe operation of NW Natural's above and below-ground facilities including LNG Plants and underground natural gas storage facilities. These risk reduction actions include:

- Seismic vulnerability assessments of LNG Plants, the Mist Underground Storage Facility, and Transmission Pipeline System as recommended by SB 33 (2013) and consistent with the Governor's Resiliency 2025 Plan
- Accelerated replacement of vintage materials
- In line assessment of Transmission pipelines outside of high and moderate consequence areas.
- Development of a PSMS (Pipeline Safety Management System)
- Proactive EFV installation.
- Locate ticket risk modeling.
- Natural forces assessments of NW Natural's transmission system as part of NW Natural patrol and surveillance programs.
- Installation of guard posts and traffic barricades to protect above ground facilities from vehicular damage.

5 Projected and Preliminary Costs Presented in this Plan

The 2025 Capital and O&M costs presented in this plan are projected based on current expenditures for each of the identified projects through the end of the year. Costs presented for the significant safety initiatives are preliminary for planning purposes and do not include NW Natural overhead costs. Costs for safety projects under consideration will be presented in future SPPs.

6 2025 Capital Safety Investment

In 2025, NW Natural estimates it will invest $18.8 MM in capital to comply with DIMP, TIMP, and other regulations. Significant projects in this category include:

6.1 S03 Salem Bypass Trans ILI (2024-25 estimate of $5.1MM)

This project involves the first inline inspection assessment of the 8" Salem Bypass Trans line which was primarily built in 1958 to support north Salem and Keizer. This pipeline is an approximately 5.5-mile transmission pipeline that initiates at a station near the Marion St. Bridge in downtown Salem and runs north and east to a valve station at Hwy 99E and Blossom Rd. NE. Work on this project will begin in 2024 with planned completion in the fall of 2025.

6.2 S18 Willamette Valley Trans ILI (2024-25 estimate of $800k):

This project involves the first inline inspection assessment of the 12" Granger Trans line which is an approximately 4 miles of transmission pipeline that supports the city of Keizer and Salem. This pipeline initiates at the Brooks regional station in Brooks, OR and runs south along Hwy 99E where it terminates at a valve station at Hwy 99E and Blossom Dr. NE. Work on this project will begin in 2024 with planned completion in the fall of 2025.

6.3 Hwy 212 (2024-25 estimate of $2 MM):

This project involves the relocation of approximately 2500 ft. of 12" transmission main located on the south side of Hwy 212 in Clackamas. During routine pipeline patrols in 2023 it was discovered that increased flow in the Clackamas River adjacent to the 12" transmission main had caused erosion to the northern bank of the river near the pipeline. Further monitoring through the winter of 2023-24 resulted in an increased observation of this erosion that posed an increased risk to the pipeline such that relocation was recommended. Work on this project will begin in 2024 with planned completion in the fall of 2025.

6.4 GP Wauna (2024-25 estimate of $1 MM):

During standard maintenance activities it was identified that the 8" transmission main that provides natural gas to the GP Wauna facility was located at a depth that did not meet current standards and was at risk due to ditch clearing activities that occur as the pipeline crosses US Highway 30. NW Natural has coordinated with the Operations department at GP Wauna to relocate a section of pipe to a proper depth while minimizing disruption at the GP Wauna facility. Work on this project is scheduled to begin in 2024 with a completion in 2025.

6.5 Pro-active EFV Installations (2025 estimate of $1MM):

On October 14, 2016, the U.S. Department of Transportation's ("DOT's") Pipeline and Hazardous Materials Safety Administration ("PHMSA") adopted code requiring the installation of EFVs or shut-off valves on all new or replaced branched service lines (Docket No. PHMSA-2011-009). While the code requires EFV installation on all new or replaced branched service lines, it did not require retrofitting EFVs on existing services.

NW Natural believes a proactive EFV installation program is a prudent action that can mitigate the consequence of a gas release resulting from excavation damage to a gas service line. NW Natural is implementing a policy to retrofit EFVs on existing gas service lines when the buried portion of the service line is exposed, and the work involves the interruption of gas service.

This pro-active EFV program was initiated in 2020 and will continue to be a safety program.

6.6 Sewer Crossbore Inspections (2025 estimate of $1.2MM):

The sewer crossbore program involves the visual inspection of sanitary sewers for incidences of gas line crossbores. In installations where trenchless technology was used to install polyethylene pipe, there exists the possibility the gas line was bored through a sewer main or lateral. NW Natural's policy is to expose all foreign line crossings when performing trenchless work. Sewer crossbores typically occur when facility owners fail to locate their pipe, creating a situation where NW Natural is unable to expose facilities during construction. This is an industry-wide threat. Although sewer crossbores are not isolated to gas operators, the consequence when gas lines are involved can be high. This program identifies existing trenchless polyethylene installations and inspects the sewers in the vicinity to identify crossbores.

6.7 Underground Storage – Well Integrity (2025 estimate of $6.2 MM)

On December 19, 2016, PHMSA issued an interim final rule ("IFR") establishing regulations for underground natural gas storage facilities (UNGSF). The IFR incorporated by reference RP 1171, "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs" (First Edition, September 2015). The IFR implemented PHMSA's authority to regulate underground gas storage and the Congressional mandate in section 12 of the PIPES Act to establish minimum safety standards.

The final rule published on February 12, 2020, modified compliance timelines, clarified regulatory roles, reduced recordkeeping and reporting requirements, and formalized integrity management practices. In accordance with the final rule, NW Natural is running baseline casing inspection logs on each of its active gas storage wells prior to the March 13, 2027, deadline.

Work in 2025 will involve one evaluation for potential plug and abandonment and replacement of three separators.

6.8 Other safety projects and programs (2025 estimate of $1.5 MM):

Pipeline Replacement due to Seismic/Natural Forces

Portions of NW Natural's distribution and transmission system cross through landslide faults, seismic faults, sensitive areas, and waterways. Due to significant weather events or the passage of time, the integrity of these pipelines may be compromised. When identified during patrols, routine maintenance, or other stakeholders, the Integrity Team develops plans to remediate these at-risk pipelines as they are identified.

Valve Isolation Plans

NW Natural is working to develop a strategy for identifying and installing additional valves in the distribution system to assist in the isolation of portions of the distribution system in case of an emergency or third-party damage.

Meter Protection Installation

NW Natural will continue installation of guard posts adjacent to meter sets that are determined to be at risk of damage due to vehicle or equipment contact.

Pipeline Modification due to ROW Encroachment

Patrols of NW Natural Pipelines may discover structures or other encroachments built over or adjacent to pipelines that can impact the safe operation of or access to a pipeline. This program works with landowners to remediate these encroachments.

Pipeline Material Identification (PMI)

At selected transmission pipeline anomaly remediation sites, NW Natural has instituted a process using technology to non-destructively test and acquire data regarding pipe material properties. In addition, when the Transmission Integrity rule went into effect over twenty years ago, NW Natural began keeping short (18"-24" long) sections of pipe for future reference. These spools were destructively tested to obtain pipe material properties that were not required as part of the original installation documentation. The material data

obtained through this program are being stored in the permanent record for each pipe segment.

Non-hazardous Leakage Projects
As part of NW Natural's continued efforts to reduce fugitive methane emissions, actions are being taken to proactively replace facilities identified as producing non-hazardous leaks. Per NW Natural Standard Practices these facilities are reevaluated and monitored on a routine basis until the leak classification changes or the facility is repaired or replaced. To address these frequent revaluations and reduce fugitive methane emissions a more proactive approach is being taken towards these facilities and projects are being developed to accelerate replacements.

Removal of Class A Services
NW Natural has performed work to eliminate a low-pressure system and transition to a full distribution system. During this transition to eliminate the low-pressure system a small number of Class A services still exist in the system. These Class A services have an MAOP of 12 inches of water column and are a legacy from the low-pressure system. NW Natural has initiated DIMP project to work with these customers to eliminate these Class A services from the system.

Idle Risers
Idle risers are the above ground portion of a service line that remains after meter removal when a customer closes their account, or a home or business is vacated. In these cases NW Natural maintains the service (idle) riser above ground where it is capped/plugged and tagged as idle. These idle risers are maintained in accordance with code requirements in the event a customer or a new tenant requests gas service. Over extended periods of time and in some instances these idle risers may present an elevated risk of damage. In 2025 NW Natural will develop a process to identify at risk idle risers and begin development of a program to remove them and abandon the service line.

6.9 Historical Capital Expenditure – Safety Project Plan (System Integrity)

The Historical Capital Expenditures below are actual expenditures for each of the presented years.

Year	Expenditure
2015	$17,190,356*
2016	$ 7,772,763
2017	$ 5,925,409
2018	$ 9,699,814
2019	$10,231,431
2020	$ 8,900,000
2021	$ 8,200,000
2022	$ 9,000,000

2023 $13,000,000
2024 $14,500,000
*Final year of known bare steel main replacement

Historical capital expenditures include:

- Work to modify pipelines to accept inline inspection devices, including removal or replacement of non-piggable fittings and facilities required to launch and receive inline inspection devices.
- Pipeline relocation to mitigate threats including outside forces and natural forces. This work does not include relocations due to utility conflicts, or third-party improvement projects.
- Pipe replacements and testing in compliance with federal and state regulations.
- Ongoing DIMP AA programs/projects such as Vintage Plastic, Guard post installations, Proactive EFV installations, etc.

7 2025 O&M Expenditures

In 2025 NW Natural expects to spend $6.425MM in O&M to address and comply with DIMP, TIMP, damage prevention, and public awareness.

Activities that reflect expenditures in this category include costs for supplies (office/field), reference materials, education (conferences/workshops), vendor and contract costs associated with transmission assessments, public awareness program materials, advertisements and mailings, and natural forces investigation and remediation. Additionally, this category covers the development, initiation, and execution of studies and consulting fees related to integrity requirements, such as class location studies and third-party geotechnical site evaluations to address and mitigate risk.

O&M also includes some non-capital internal labor in support of NW Natural's system integrity program ("SIP"). These costs include the Integrity Management staff (7 FTE), damage prevention staff (4.5 FTE) involved in damage prevention/investigation, and a public information officer for safety outreach, training, and program administration. The Integrity Management group may also utilize other internal resources in support of SIP activities which includes GIS analysts, Customer Service, Construction, and other subject matter experts. Significant O&M projects include:

7.1 Transmission Inline and Direct Assessment Reassessment and Remediation (2025 estimate of $3MM):

This work includes the federally prescribed seven-year reassessment of transmission pipelines in HCAs and is comprised of both inline inspection and direct assessment of transmission assets and associated repairs.

7.2 Natural Forces (2025 estimate of $125,000):

Where the threat of natural forces can be mitigated without pipe replacement or rerouting, NW Natural may choose to address the threat through site work. This option is necessary in situations where a reroute is not feasible due to environmental restrictions or where a pipeline serves a critical customer or provides a single feed to a distribution system. Work may include armoring of slopes, re-grading of sites, culvert improvements, and retaining structures to address land movement and drainage issues.

7.3 Damage Prevention (2025 estimate of $850,000):

In compliance with DIMP regulations, and to address the single largest threat to gas facilities, NW Natural maintains a damage prevention department. The department consists of a supervisor and 4.5 FTE damage prevention specialists whose responsibilities include damage prevention through high risk locate ticket intervention, training, attendance at pre-construction meetings, participation in Utility Coordinating Councils, and support of the 811 One-call system. Damage prevention specialists are also responsible for the investigation, enforcement, and contractor training related to excavation and third-party damage.

7.4 Public Awareness (2025 estimate of $850,000):

NW Natural's Public Awareness program meets the requirements mandated in API RP 1162, adopted by reference by PHMSA into Part 192.616(a), (b), and (c). This program promotes public safety through communication and outreach focused on educating customers and the public about natural gas safety. The program includes customer correspondence, mailers, advertisements, community events, mobile phone applications, and brochures to excavators, contractors, public officials, residences and businesses along pipeline rights-of-way and in high consequence areas, and floating homes.

The Public Awareness Plan utilizes television and radio advertising, bill inserts, social media, and events to promote natural gas safety awareness. Targeted outreach and public awareness materials are provided annually to customers near transmission pipelines, as well as contractors, excavators, and first responders within NW Natural's service territory.

7.5 Right-of-Way Encroachments (2025 estimate of $100,000):

Pipeline patrols are used to identify changes in site conditions. An example of such a change is the installation of structures over pipelines, and inside dedicated pipeline rights-of-way, or easements. In some instances, the remediation may involve the relocation of structures and other non-gas facilities.

7.6 Probabilistic Distribution Risk Model ($1.5MM between 2025 and 2030):

In 2023 NW Natural initiated a project to partner with a data analysis consultant to implement a Probabilistic Risk Model to assess the NW Natural distribution system. A probabilistic risk model is a model that determines the probability of failure in the system and quantifies the consequences of a failure per threat. Probabilistic Risk models have been identified by PHMSA as a best practice to proactively manage threats to the natural gas

distribution system. This risk model is a 5-year program that is scheduled to begin implementation in 2025.

7.7 Historical O&M Expenditure – Safety Project Plan (System Integrity):

The historical O&M expenditures below are actual expenditures for each of the presented years (not including PSMS, damage prevention or public awareness expenditures).

Year	Expenditure
2015	$4,034,218
2016	$4,889,618
2017	$4,771,267
2018	$4,000,000
2019	$3,052,000
2020	$3,100,000
2021	$2,900,000
2022	$2,800,000
2023	$3,000,000
2024	$ 700,000

Historic O&M expenditure included:

- Regulatory transmission assessments including the investigation and remediation of identified anomalies resulting from inline inspection (ILI re-inspections not conducted in 2024) and external corrosion direct assessment (ECDA).
- Sewer crossbore inspection program (not conducted in 2024).
- Investigation and remediation of natural forces including landslides, flooding, erosion, etc.
- Buildover remediation where structures encroach into pipeline right-of-way.
- Remediation of difficult to operate valves.
- Maintenance of Integrity Risk model as a result of geographical and system changes.

These above costs do not reflect those related to ongoing maintenance of facilities including right-of-way clearing, patrols, leakage, cathodic protection, and other ongoing routine O&M work.

8 2025 Significant Safety Initiatives

8.1 Changes in TIMP Assessment Methodology

In 2025, NW Natural will extend the use of inline inspection (ILI) for integrity assessment of transmission pipelines assessed at seven-year intervals. Inline inspection tools have the advantage over direct assessment and pressure testing because they assess the entire pipeline maintaining constant contact with the inner wall providing data allowing for the

identification of interacting anomalies such as pipe deformation and metal loss. In 2025, NW Natural will change the assessment methodology of the following pipelines.

- S18 Willamette Valley Trans – Approximately 4-mile transmission pipeline that provides gas the P30 – Central Coast Feeder to Keizer and north Salem.
- S03 Salem Bypass – Approximately 5.5 miles of transmission pipeline that supports the city of Salem and Keizer.

8.2 Pro-active EFV Installations

NW Natural has installed EFVs on all new single-family residential services since February of 1999. In 2006, Federal Code was modified to require the installation of EFVs on all new residential and small commercial services. NW Natural will continue and expand the program installing EFVs on existing residential and small commercial services when the buried portion of the service line is exposed and service to the customer is interrupted. NW Natural believes proactive installation of EFVs is a prudent and pragmatic approach that can mitigate the consequence of an excavation damage to a service line.

9 Transmission Material Verification

In compliance with recent Regulatory Mandates involving material verification of steel transmission pipelines, NW Natural has implemented a non-destructive material verification program to collect material property data on transmission pipeline assets. This program involves material testing of in-service pipelines during planned work to collect material data including metallurgy that was not required at the time of installation.

NW Natural has also developed a program to destructively test segments of pipeline that were removed from past transmission projects to collect the material property information. Collecting material information from the in-service transmission mains and the destructive tests from the historical transmission mains will allow NW Natural to develop a library of pipeline material property data.

10 Cost Benefit Analyses & Alternative Analysis

The performance of a cost benefit analysis and alternatives analysis is difficult in the context of safety programs mandated by regulation. As a result, a cost benefit analysis has not been a primary consideration in this report because these safety projects are mandated by CFR, dictated by industry best practices, or driven by operational requirements. The assigned risk and prioritization for implementing these projects are based on in-depth studies and analysis of NW Natural's transmission and distribution systems as well as plant and storage assets. Studies performed as part of normal operations provide measurable and continual feedback needed to perform safety related work for which there are few practicable alternatives.

Alternative analysis and in-depth studies are useful when they identify threats and risks that

can be mitigated or eliminated through the application of performance-based best practices, engineering analysis, operational knowledge, and subject matter experts. Where the Code of Federal Regulations prescribe compliance activity or mandate programs, the use of cost benefit, or alternative, analysis is not warranted.

When a pipeline safety initiative requires a cost benefit or alternative analysis, NW Natural may select a qualified external resource to perform the analysis.

11 Legislative Update

11.1 PHMSA Rulemaking Docket No. PHMSA-2011-0023;

Amdt. No. 192-132] RIN 2137-AF39 Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments. PHMSA published this rule on August 24, 2022. NW Natural is in compliance with the rule as published.

11.2 Docket No. PHSMA-2021-0039 Pipeline Safety NPRM: Gas Pipeline Leak Detection and Repair

On May 18, 2023, PHSMA issued a Notice of Proposed Rule Making: Gas Pipeline Leak Detection and Repair. The NPRM colloquially referred to as the LDAR rule is intended to reduce methane emissions from new and existing gas transmission and distribution pipelines, gas gathering pipelines, and underground natural gas storage facilities. NW Natural is reviewing the NPRM and will comply with the final rule when it is published in the Federal Register.

11.3 Docket No. PHSMA-2021-0046 Pipeline Safety NPRM: Safety of Gas Distribution Pipelines and Other Pipeline Safety Initiatives

On September 7, 2023, PHSMA issued a Notice of Proposed Rule Making: Safety of Gas Distribution Pipelines and Other Pipeline Safety Initiatives. PHMSA proposes revisions to the pipeline safety regulations to require operators of gas distribution pipelines to update their distribution integrity management programs (DIMP), emergency response plans, operations and maintenance manuals, and other safety practices. These proposals implement provisions of the Leonel Rondon Pipeline Safety Act—part of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020. NW Natural is reviewing the NPRM and will comply with the final rule when it is published in the Federal Register.

12 Completed Projects

Below is the list of projects scheduled to be completed in 4th quarter of 2023 and 2024.

12.1 Underground Storage – Well Integrity ($2.6MM – Actual)

This project involved the re-work and baseline assessments of two wells and reassessment of four wells in the Mist storage field. The 2024 project represents year seven of NW Natural's well integrity baseline assessment work that includes down hole assessment of production casing and replacement of select tubulars, downhole equipment, and wellhead components. The reassessments include down hole assessment of production casing and replacement of select tubulars, downhole equipment, wellhead components, and/or mechanical integrity testing. The program was developed to meet compliance with PHMSA's adoption of APR RP 1171 - Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs. The baseline assessments represent a multiyear project planned for completion in 2025. The reassessment intervals are determined by risk assessment and information from the baseline assessments. This project has been completed.

12.2 Albany Trans ILI (~2024 actual $1.3M):

This project involves the transition of the Albany Trans transmission line from ECDA to ILI assessment. The Albany transmission line is a 10" transmission main that connects to the Albany Gate in the eastern part of Albany and runs west 12 miles to serve the residential and industrial customers of Albany and Corvallis. The transmission main terminates in North Corvalis. Design work to modify the pipeline began in 2023 with construction starting in 2024; cleaning and ILI assessment, data analysis, and remediation activities will continue through the fall of 2024.

12.3 Mid-Willamette Valley Trans (~2024 Actual $1.5M):

This project involves the transition of the Mid-Willamette Valley transmission line from ECDA to ILI assessment. The Mid-Willamette Valley Transmission line is a 31 mile long 12" transmission line that connects to the P30 Central Coast Feeder near Perrydale. The line runs south where it terminates at US Hwy 20. This pipeline serves the residential and commercial customers in Monmouth and provides a connection from the Central Coast feeder to Albany/Corvallis. Design and preliminary construction work was completed in 2024. Cleaning and ILI assessment activities will continue through 2024 with data analysis and remediation/repairs completed in 2025.

12.4 Granger (~2024 Actual $1.5M):

This project involves the transition of the Granger transmission line from ECDA to ILI assessment. The Granger Transmission line is a 4.5 mile long 6" transmission line that connects to the end of the Albany Transmission main and runs north and east along US Highway 20 where it terminates near US Hwy 20 and Independence Hwy. This pipeline serves the residential and commercial customers in North Albany. Design and preliminary construction work was completed in 2024. Cleaning and ILI assessment activities will continue through 2024 with data analysis and remediation/repairs completed in 2025.

13 Conclusion

This SPP provides an overview of NW Natural's pipeline safety initiatives and commitment to the safe and reliable delivery of natural gas to the communities we serve. Through its more-than 165-year history, NW Natural has been committed to identifying threats to pipeline safety and taking steps to address and mitigate those threats. Looking forward to the role natural gas will play in our energy future, and as members of the communities we serve, NW Natural recognizes the trust placed on us by our neighbors and customers. NW Natural will continually work to ensure public safety and maintain the integrity of our natural gas system.

NW Natural®

250 SW Taylor Street
Portland, OR 97204

503-226-4211
nwnatural.com

September 27, 2023

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attention: Filing Center
201 High Street SE Suite 100
PO Box 1088
Salem, Oregon 97308-1088

Re: UM 1900: NW Natural's 2024 Annual Oregon Safety Project Plan in Compliance with OPUC Order No. 17-084

Northwest Natural Gas Company, dba NW Natural (NW Natural or Company), hereby submits its 2024 Safety Project Plan in compliance with Commission Order No. 17-084 entered March 6, 2017.

Please address correspondence on this matter to me with copies to the following:

eFiling
Rates & Regulatory Affairs
NW Natural
250 SW Taylor Street
Portland, Oregon 97204
Telephone: (503) 610-7330
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Sincerely,

/s/ Rebecca Trujillo

Rebecca Trujillo
Regulatory Consultant

Enclosure

NW Natural®

2024 SAFETY PROJECT PLAN

OREGON

September 27, 2023

250 SW Taylor Street
Portland, Oregon 97204
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NW Natural®

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1 Introduction

In compliance with the Oregon Public Utility Commission ("Commission" or "OPUC") Order No 17-084 ("Order") in Docket UM 1722, this Safety Project Plan ("SPP") outlines NW Natural's safety project investments for 2024. The SPP includes updated capital and O&M projects and programs and projects that carry over from 2023.

This SPP demonstrates NW Natural's commitment to pipeline safety by providing insight into NW Natural's safety activities and identifies NW Natural's response to regulatory changes that may drive safety program priorities or modify existing programs. In the future if NW Natural seeks approval for a Safety Cost Recovery Mechanism (SCRM), this SPP is intended to expedite the review process of safety investments.

Safety is a core value at NW Natural and we appreciate the opportunity to present this information to the Commission.

2 Background Information

NW Natural is a regulated natural gas utility conducting business in Oregon and southwest Washington. The Company serves ~790,000 customers and owns and operates ~660 miles of natural gas transmission pipeline, and ~14,200 miles of distribution pipelines. In addition, NW Natural operates three energy storage facilities in Oregon – Portland and Newport LNG Plants and Mist Underground Storage.

NW Natural's pipelines and storage facilities are governed by:

- 49 CFR Part 192 – Minimum Safety Standard – Transmission & Distribution Systems
- 49 CFR Part 193 – LNG Safety Standards
- 49 CFR Part 196 – Protection of Underground Pipelines from Excavations Activity
- Additional OARs (OAR 860-024 – Safety, OAR 860-031 – Pipeline Inspections), and ORSs such as ORS 757.039 – Regulation of hazardous substance distribution and storage operations, and ORS 757.542-993 – One call notification.

In addition to the federal and state regulations identified above, NW Natural's safety program considers the findings of Oregon House Resolution 3 (HR 3, 2011) which directed the Oregon Seismic Safety Policy Advisory Commission to prepare the Oregon Resiliency Plan with the purpose of identifying recommendations for how Oregon's critical energy infrastructures could be made seismically resilient against a Cascadia subduction zone earthquake. Upon completion of that work on February 28, 2013, the Oregon Senate passed Senate Bill 33 (SB 33, 2013), which established the Governor's Task Force on Oregon Resilience Plan ("ORP") Implementation ("Task Force"). In October 2014, the Task Force issued a report recommending that the Commission require regulated energy providers to conduct seismic assessments of

regulated facilities and recommended that the Commission allow cost recovery for prudent investments related to assessments and mitigation of vulnerabilities identified during those assessments. In October 2018, Governor Kate Brown presented the "Resiliency 2025" plan, titled "Improving Our Readiness for the Cascadia Earthquake and Tsunami" ("Resiliency 2025 Plan"). The Resiliency 2025 Plan follows the 2013 ORP and outlines six key strategies for the State of Oregon. Its vision is to "protect all Oregonians by ensuring we are prepared to survive and recover from the expected 9.0 magnitude Cascadia earthquake and ensuing tsunami." The key strategy of the Resiliency 2025 Plan to improve the energy infrastructure is to "develop a plan for the Critical Energy Infrastructure Hub to prevent and mitigate catastrophic failure and ensure fuel supplies and alternate energy sources are available to responders and the public."

3 Threat Identification

NW Natural's four highest ranking threats, as identified in the DIMP Plan are:

3.1 Excavation Damage

Excavation damage continues to be the principal threat to NW Natural's gas distribution system, comprising approximately 86 percent of all recorded leak repairs. Excavation damage is a system-wide threat brought on predominantly by improper excavation practices. NW Natural's efforts to reduce excavation damages are described below.

3.1.1 Excavation Training and Education:

NW Natural actively engages in training and education for contractors, general public, and other utilities, to promote safe excavation procedures and practices. These efforts include classes on Oregon dig laws, displays at public events, and the use of media including print, radio, television, and internet to promote safety, best practices, and the use of 811.

NW Natural's Damage Prevention Department works to reduce the number of excavation damages through investigation, cause analysis, and proactively works to identify and support contractors engaging in high-risk construction activity.

3.1.2 One-Call Notification Practices:

NW Natural actively participates in local and state-level Utility Coordinating Councils as well as the One Call Utility Notification board. A primary function of these organizations is to reduce damages to underground utilities through excavation best practices, public awareness, and the use of the Oregon one call system (811).

NW Natural also maintains a robust Public Awareness Program which includes advertising, direct mailing, and public event outreach to increase this awareness.

3.1.3 Locating Practices:

NW Natural is an active member of Oregon's one call system and responds to all locate requests. Due to the high volume of locate requests this work is contracted. All locating is performed by NW Natural qualified personnel and oversight is performed by Company contract management personnel. In addition, locating activity is included in NW Natural's Quality Assurance program to minimize the incidences of errors, mismarks, and missed due dates.

3.1.4 Incorrect Facility Marking:

Incorrectly marked facilities may be due to underground interference, equipment issues, inaccurate facility maps, or procedural issues. Locating personnel responsible for a mismark receive additional training and are required to re-qualify prior to being allowed to locate gas facilities. Review of mismarks are conducted by supervisor or other qualified personnel and the results are used to identify deficiencies, correct maps, and ensure the facility can be reliably located.

3.2 Material, Weld or Joint Failure

Material, weld, or joint failure is the second largest threat to the NW Natural gas distribution system, comprising approximately 9 percent of all recorded leak repairs. NW Natural is proactive in its efforts to reduce these occurrences, as described below.

3.2.1 Plastic Pipe Installed from 1960s to 1980s:

NW Natural makes every effort to identify all pre-1982 plastic pipe installations, analyze leak histories, evaluate any conditions that may threaten integrity of the pipe, and take appropriate remedial action, including replacement, to mitigate risks to public safety.

3.2.2 Plexco Service Tee Celcon Caps:

NW Natural is aware of industry issues regarding Plexco Service Tee Celcon Caps possibly leaking when over-tightened during installation. These caps exist within the gas distribution system and are replaced as found and scheduled for replacement if leaks are identified.

3.2.3 Polyethylene ("PE") Fusion Failure:

NW Natural has a robust training and Quality Assurance/Quality Control program in place to ensure proper PE fusion quality. This program includes testing, biannual qualification, and ongoing training. All PE fusions are visually inspected, and pressure tested prior to being placed in service.

3.2.4 Flat Back Risers:

In 2012 NW Natural identified a type of riser stop valve, internally known as a "Flat Back Riser," that contained components prone to atmospheric corrosion in the coastal areas of NW Natural's service territory. NW Natural identified that corrosion failure on a

retaining pin could result in a hazardous leak. NW Natural developed an Accelerated Action Plan to replace these valves in coastal areas.

3.3 Corrosion

Corrosion is the third largest threat to the NW Natural's gas distribution system, comprising less than 2 percent of all recorded leak repairs. NW Natural's efforts to reduce these occurrences are described below.

3.3.1 Pipe Replacement:

The primary driver for external corrosion system-wide is steel pipe. At this time NW Natural's distribution system in Oregon is approximately 50% coated and cathodically protected steel and 50% polyethylene. During all pipe replacement projects consideration is given to replacing existing steel pipes, valves, and fittings with polyethylene to mitigate the threat of corrosion. In 2015 NW Natural completed the replacement of all known un-coated bare steel pipe eliminating the single largest corrosion threat.

3.3.2 Pipe Casings:

Steel casings are primarily used to protect or facilitate the installation of mains and services underground and are fitted with seals to prevent water intrusion, spacers to prevent contact between the casing and gas carrying pipe, and vents.

NW Natural inspects steel casings annually to identify problems such as contact between the casing and gas pipe, or water intrusion. If a "short" or other anomaly is identified a work order is created to address the concern.

At NW Natural the installation of casings has been largely replaced by HDD (Horizontal Directional Drilling) installation. During pipeline improvement projects existing casings are evaluated for replacement by HDD or alternatives.

3.3.3 Atmospheric Corrosion:

NW Natural's system includes facilities such as risers, regulators, station piping, bridge crossings and other above ground facilities that are susceptible to atmospheric corrosion.

NW Natural's atmospheric corrosion mitigation plan includes replacement of facilities when appropriate as well as protective coatings such as epoxies, paint, wax, other corrosion resistant materials, and enhanced inspections in locations with an elevated risk of corrosion.

3.3.4 Exposed Pipe Inspections

During normal operations when a buried pipeline is exposed crews inspect the pipe and protective coating for evidence of corrosion, or coating anomalies that can lead to future corrosion. Coating repairs or pipe replacements are completed before the pipe backfilled and placed back in service.

3.4 Equipment Failure

Equipment Failure is the fourth largest threat to the NW Natural gas distribution system, comprising approximately 1 percent of all recorded leak repairs. NW Natural's efforts to reduce these occurrences are described below.

3.4.1 Valves:

Valves are vital to the safe operation of a gas distribution system. NW Natural has in place a key operating valve inspection and maintenance program to ensure key valves are operable and available for use. Valves that are found to be inoperable, inaccessible, and/or paved over are identified and remediated as necessary.

3.4.2 Pressure Control / Relief Equipment:

NW Natural has an established inspection and maintenance program in place for pressure control/relief equipment to ensure reliable and safe operation.

3.4.3 Mechanical Couplings:

Pipe may pull out from compression couplings due to tensile forces including excavation damage, cyclic fatigue from changes in the temperature of natural gas as a result of the Joule-Thomson effect, ground movement from earthquakes or after heavy rains. Mechanical fitting failures are investigated, tracked, and reported per PHMSA and OPUC requirements.

In the past as an alternative to welding small diameter steel fittings, mechanical couplings were sometimes used to install valves and service tees. These types of fittings may develop leaks through the elastomer seal between the coupling and the pipe. NW Natural replaces these fittings with welded steel fittings or polyethylene as discovered during routine operations and maintenance activity.

3.4.4 Other:

Other types of material or equipment failure may occur in the gas distribution system. Failure reports are reviewed to detect trends or patterns that may affect the distribution system.

Many of the safety projects identified in this plan are in direct response to the above threats, and to maintain compliance with safety codes and regulations.

4 Safety Activities Performed by NW Natural

Safety activities at NW Natural can be divided into categories:

4.1 Prescriptive Regulatory Actions – Includes actions which must be performed to meet minimum federal safety standards.

49 CFR 192 includes multiple prescriptive activities, intended to safeguard public safety, and fall into broad categories such as "operations" (Subpart L) and "maintenance" (Subpart M). Most of these activities require inspections at prescribed intervals to confirm that a facility or asset is meeting operational requirements prescribed by federal code. These activities provide the baseline data for other performance-based activities and include, but are not limited to:

- Atmospheric corrosion surveys
- Leakage surveys
- Cathodic protection surveys
- Right of way ("ROW") patrols
- Valve maintenance
- Water crossing inspections
- Odorization
- Odorometer Reads
- Line Marking
- Pressure Regulation Inspection
- Large Meter Inspections
- Record Keeping
- Control Room Management
- Bridgeline Inspections
- Equipment Calibration
- Houseboat Inspections
- Transmission Integrity

The safety activities from this category are prescriptive in nature and are not driven by risk analysis alone. Because these activities are required, they are not discussed further in this SPP, which instead focuses on projects and/or programs identified by NW Natural as essential to enhancing safety and reliability.

4.1.1 Transmission Integrity (TIMP)

Transmission Integrity refers to 49 CFR 192 Subpart O-Gas Transmission Pipeline Integrity Management. This federally mandated program covers natural gas transmission pipelines located in High Consequence ("HCA") and Moderate Consequence ("MCA") areas. NW Natural exceeds code requirements in TIMP to address conditions outside of HCA and MCA's

Activities in this category include baseline assessments and reassessments of transmission lines using in-line inspection ("ILI") and other direct assessment methods. They may also include pipeline replacements and modifications in compliance with integrity management rules, best practices, and relocation of facilities to mitigate threats posed by natural forces such as flooding, land movement, and erosion.

4.2 Proactive, Performance-Based Actions

Other sections of 49 CFR 192 include more proactive performance-based risk reduction activities, such as Subpart P – Distribution Integrity Management Program ("DIMP"), Damage Prevention, and Public Awareness. These programs focus on mitigating pipeline safety risk.

4.2.1 Distribution Integrity (DIMP)

Distribution Integrity is outlined in 49 CFR 192 Subpart P- Gas Distribution Pipeline Integrity Management. This federally mandated program requires operators to create a written Integrity Management Program that takes into consideration: system knowledge, threat identification, evaluation and risk ranking, identification, and implementation of measures to address risk, measurement of results, and reporting.

Activities in this category include projects warranting Accelerated Action ("AA") to address a system integrity risk. These AA projects are identified through risk modeling, industry identified threats, and by subject matter experts within the Company, and include:

- Replacement of vintage plastic services,
- Relocation of facilities under structures,
- Replacement of valves and fittings susceptible to leakage,
- Protection of above grade gas facilities,
- Crossbore investigation, and
- Relocation of distribution gas lines to mitigate threats posed by natural forces such as:
  - Flooding
  - Land movement, and
  - Erosion.
- Enhanced EFV Installation – installation of EFVs on services that were installed prior to the EFV rule issued in 2006.
- Dithiazine – a sulfur compound found in natural gas that has been known to cause equipment failure especially in district regulators.

4.3 Safety Policy and Practices

NW Natural also implements risk reduction activities not explicitly required by the federal code. These actions have been identified as prudent safety practices intended to enhance public safety, improve system reliability, and maintain the safe operation of NW Natural's

above and below-ground facilities including LNG Plants and underground natural gas storage facilities. These risk reduction actions include:

- Seismic vulnerability assessments of LNG Plants, the Mist Underground Storage Facility, and Transmission Pipeline System as recommended by SB 33 (2013) and consistent with the Governor's Resiliency 2025 Plan
- Accelerated replacement of vintage materials
- In line assessment of Transmission pipelines outside of high and moderate consequence areas.
- Development of a PSMS (Pipeline Safety Management System)
- Proactive EFV installation
- Locate ticket risk modeling.
- Natural forces assessments of NW Natural's transmission system as part of NW Natural patrol and surveillance programs.
- Installation of Rupture Mitigation Valves (RMVs) in areas susceptible to land movement due to natural forces.
- Installation of guard posts and traffic barricades to protect above ground facilities from vehicular damage.

5 Projected and Preliminary Costs Presented in this Plan

The 2024 Capital and O&M costs presented in this plan are projected based on current expenditures for each of the identified projects through the end of the year. Costs presented for the significant safety initiatives are preliminary for planning purposes and do not include NW Natural overhead costs. Costs for safety projects under consideration will be presented in future SPPs.

6 2024 Capital Safety Investment

In 2024, NW Natural estimates it will invest $17.5 MM in capital to comply with DIMP, TIMP, and other regulations. Significant projects in this category include:

6.1 S36 Mid-Willamette Valley Trans (2023-24 estimate of $1.5 MM):

This project involves the first inline inspection assessment of the 12" Mid-Willamette Valley Trans line which was built in multiple stages beginning in 2005 as part of a bare main replacement project in the area. This pipeline is an approximately 32-mile transmission pipeline that provides gas from the Newport LNG facility to communities in the Mid-Willamette Valley including Albany and Corvallis. Work on this project will begin in 2023 with planned completion in the fall of 2024.

6.2 S24 Granger (2023-24 estimate of $1.5 MM):

This project involves the inline inspection assessment of the 6" Granger Trans line which is an approximately 4.5 miles of transmission pipeline that supports the city of Albany. This pipeline initiates at the Corvallis Granger station north of Corvallis and is routed along US Hwy 20 where it terminates at a valve station on the north side of US Hwy 20 when it transitions to an 8" high pressure distribution main. Work on this project will begin in 2023 with planned completion in the fall of 2024.

6.3 S22 10" Albany Trans (2023-24 estimate of $1.5 MM):

This project involves the inline inspection assessment of the 10" Albany Trans line which is approximately 12-mile transmission pipeline that initiates from a gate station east of Albany and is routed through Albany where it terminates at the Corvallis Granger Regional Station north of Corvallis. This pipeline is the primary feed for the Albany Corvallis area include Oregon State University. Work on this project will begin in 2023 with planned completion in the fall of 2024.

6.4 Seismic/RMV Projects (2023-24 estimate of $1.2 MM):

In 2023 NW Natural worked with an Engineering consultant to develop a risk model of the NW Natural transmission and high-pressure distribution system utilizing the regulations in the PHMSA Rupture Mitigation Valve ("RMV") Rule and a seismic study created in 2020. This risk model prioritized transmission and high-pressure distribution segments based on a risk score. NW Natural is working to implement the results of this risk analysis to select critical valve locations that need RMV technology based on risk.

6.5 Probabilistic Distribution Risk Model (2023-24 estimate of $1.6MM):

In 2023 NW Natural initiated a project to partner with a data analysis consultant to implement a Probabilistic Risk Model to assess the NW Natural distribution system. A probabilistic risk model is a model that determines the probability of failure in the system and quantifies the consequences of a failure per threat. Probabilistic Risk models have been identified by PHMSA as a best practice to proactively manage threats to the natural gas distribution system. This risk model is a 5-year program that is schedule to begin implementation in 2024.

6.6 Pro-active EFV Installations (2024 estimate of $3MM):

On October 14, 2016, the U.S. Department of Transportation's ("DOT's") Pipeline and Hazardous Materials Safety Administration ("PHMSA") adopted code requiring the installation of EFVs or shut-off valves on all new or replaced branched service lines (Docket No. PHMSA-2011-009). While the code requires EFV installations be installed in all new or replaced branched service lines, it did not require retrofitting EFVs on existing services.

NW Natural believes a proactive EFV installation program is a prudent action that can mitigate the consequence of a gas release resulting from excavation damage to a gas service line. NW Natural is implementing a policy to retrofit EFVs on existing gas service lines when the buried portion of the service line is exposed, and the work involves the interruption of gas service.

This pro-active EFV program was initiated in 2020 and will continue to be a safety program.

6.7 Underground Storage – Well Integrity (2024 estimate of $5.7 MM)

On December 19, 2016, PHMSA issued an interim final rule ("IFR") establishing regulations for underground natural gas storage facilities (UNGSF). The IFR incorporated by reference RP 1171, "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs" (First Edition, September 2015). The IFR implemented PHMSA's authority to regulate underground gas storage and the Congressional mandate in section 12 of the PIPES Act to establish minimum safety standards.

The final rule published on February 12, 2020, modified compliance timelines, clarified regulatory roles, reduced recordkeeping and reporting requirements, and formalized integrity management practices. In accordance with the final rule, NW Natural is running baseline casing inspection logs on each of its active gas storage wells prior to the March 13, 2027, deadline.

Work in 2024 will involve assessments of the production casings. The assessments will include downhole wireline logging of the production casing strings using both multi-arm caliper and magnetic flux tools to identify deformations and metal loss features.

6.8 Other safety projects and programs (2024 estimate of $1.5 MM):

Pipeline Replacement due to Seismic/Natural Forces

Portions of NW Natural's distribution and transmission system cross through landslide faults, seismic faults, sensitive areas, and waterways. Due to significant weather events or the passage of time, the integrity of these pipelines may become at risk. When identified during patrols, routine maintenance, or other stakeholders, the Integrity Team develops plans to remediate these at-risk pipelines as they are identified.

Valve Isolation Plans

NW Natural is working to develop a strategy for identifying and installing additional valves in the distribution system to assist in the isolation of portions of the distribution system in case of an emergency or third-party damage.

Meter Protection Installation

NW Natural will continue installation of guard posts adjacent to meter sets that are determined to be at risk of damage due to vehicle or equipment contact.

Pipeline Modification due to ROW Encroachment
Patrols of NW Natural Pipelines may discover structures or other encroachments built over or adjacent to pipelines that can impact the safe operation of or access to a pipeline. This program works with landowners to remediate these encroachments.

Pipeline Material Identification (PMI)
At selected transmission pipeline anomaly remediation sites, NW Natural has instituted a process using technology to non-destructively test and acquire data regarding pipe material properties. In addition, when the Transmission Integrity rule went into effect over twenty years ago, NW Natural began keeping short (18"-24" long) sections of pipe for future reference. These spools will be destructively tested to obtain pipe material properties that were not required as part of the original installation documentation. The material data obtained through this program will be stored in the permanent record for each pipe segment.

Non-hazardous Leakage Projects
As part of NW Natural's continued efforts to reduce fugitive methane emissions an approach has been taken to proactive replace facilities that have been identified as producing non-hazardous leaks. Per NW Natural Standard Practices these facilities previously could be reevaluated on a more frequent basis until the leak classification changes or the facility is repaired or replaced. In order to address these frequent revaluations and reduce fugitive methane emissions a more proactive approach is being taken towards these facilities and projects are being developed to accelerate replacements.

Removal of Class A Services
NW Natural in recent history performed work to eliminate a low-pressure system and transition to a full distribution system. During this transition to eliminate the low-pressure system a small number of Class A services still exist in the system. These Class A services have an MAOP of 12 inches of water column and are a legacy from the low-pressure system. NW Natural has taken on a DIMP project to work with these customers to eliminate these Class A services from the system.

6.9 Historical Capital Expenditure – Safety Project Plan (System Integrity)

The Historical Capital Expenditures below are actual expenditures for each of the presented years.

Year	Expenditure
2015	$17,190,356*
2016	$ 7,772,763
2017	$ 5,925,409
2018	$ 9,699,814
2019	$10,231,431
2020	$ 8,900,000
2021	$ 8,200,000

2022 $ 9,000,000
2023 $13,000,000

*Final year of known bare steel main replacement

Historical capital expenditures include:

- Work to modify pipelines to accept inline inspection devices, including removal or replacement of non-piggable fittings and facilities required to launch and receive inline inspection devices.
- Pipeline relocation to mitigate threats including outside forces and natural forces. This work does not include relocations due to utility conflicts, or third-party improvement projects.
- Pipe replacements and testing in compliance with federal and state regulations.
- Ongoing DIMP AA programs/projects such as Vintage Plastic, Guard post installations, Proactive EFV installations, etc.

7 2024 O&M Expenditures

In 2024 NW Natural expects to spend $4.7MM in O&M to address and comply with DIMP, TIMP, damage prevention, and public awareness.

Activities that reflect expenditures in this category include costs for supplies (office/field), reference materials, education (conferences/workshops), vendor and contract costs associated with transmission assessments, sewer crossbore investigations and remediation, public awareness program materials, advertisements and mailings, and natural forces investigation and remediation. Additionally, this category covers the development, initiation, and execution of studies and consulting fees related to integrity requirements, such as class location studies and third-party geotechnical site evaluations to address and mitigate risk.

O&M also includes some non-capital internal labor in support of NW Natural's system integrity program ("SIP"). These costs include the Integrity Management staff (7 FTE), damage prevention staff (5 FTE) involved in damage prevention/investigation, and a public information officer for safety outreach, training, and program administration. The Integrity Management group may also utilize other internal resources in support of SIP activities which includes GIS analysts, Customer Service, Construction, and other subject matter experts. Significant O&M projects include:

7.1 Sewer Crossbore Inspections (2024 estimate of $1.2MM):

The sewer crossbore program involves the visual inspection of sanitary sewers for incidences of gas line crossbores. In installations where trenchless technology was used to install polyethylene pipe, there exists the possibility the gas line was bored through a sewer main or lateral. NW Natural's policy is to expose all foreign line crossings when performing trenchless

work. Sewer crossbores typically occur when facility owners fail to locate their pipe, creating a situation where NW Natural is unable to expose facilities during construction. This is an industry-wide threat. Although sewer crossbores are not isolated to gas operators, the consequence when gas lines are involved can be high. This program identifies existing trenchless polyethylene installations and inspects the sewers in the vicinity to identify crossbores.

7.2 Transmission Inline and Direct Assessment Reassessment and Remediation (2024 estimate of $1.3MM):

This work includes the federally prescribed seven-year reassessment of transmission pipelines in HCAs and is comprised of both inline inspection and direct assessment of transmission assets and associated repairs.

7.3 Natural Forces (2024 estimate of $300,000):

Where the threat of natural forces can be mitigated without pipe replacement or rerouting, NW Natural may choose to address the threat through site work. This option is necessary in situations where a reroute is not feasible due to environmental restrictions or where a pipeline serves a critical customer or provides a single feed to a distribution system. Work may include armoring of slopes, re-grading of sites, culvert improvements, and retaining structures to address land movement and drainage issues.

7.4 Damage Prevention (2024 estimate of $800,000):

In compliance with DIMP regulations, and to address the single largest threat to gas facilities, NW Natural maintains a damage prevention department. The department consists of a supervisor and 4 FTE damage prevention specialists whose responsibilities include damage prevention through high risk locate ticket intervention, training, attendance at pre-construction meetings, participation in Utility Coordinating Councils, and support of the 811 One-call system. Damage prevention specialists are also responsible for the investigation, enforcement, and contractor training related to excavation and third-party damage.

7.5 Public Awareness (2024 estimate of $1,000,000):

NW Natural's Public Awareness program meets the requirements mandated in API RP 1162, adopted by reference by PHMSA into Part 192.616(a), (b), and (c). This program promotes public safety through communication and outreach focused on educating customers and the public about natural gas safety. The program includes customer correspondence, mailers, advertisements, community events, mobile phone applications, and brochures to excavators, contractors, public officials, residences and businesses along pipeline rights-of-way and in high consequence areas, and floating homes.

The Public Awareness Plan utilizes television and radio advertising, bill inserts, social media, and events to promote natural gas safety awareness. Targeted outreach and public awareness materials are provided annually to customers near transmission pipelines, as well as contractors, excavators, and first responders within NW Natural's service territory.

7.6 Right-of-Way Encroachments (2024 estimate of $100,000):

Pipeline patrols are used to identify changes in site conditions. An example of such a change is the installation of structures over pipelines, and inside dedicated pipeline rights-of-way, or easements. In some instances, the remediation may involve the relocation of structures and other non-gas facilities.

7.7 Historical O&M Expenditure – Safety Project Plan (System Integrity):

The historical O&M expenditures below are actual expenditures for each of the presented years (not including PSMS, damage prevention or public awareness expenditures).

Year	Expenditure
2015	$4,034,218
2016	$4,889,618
2017	$4,771,267
2018	$4,000,000
2019	$3,052,000
2020	$3,100,000
2021	$2,900,000
2022	$2,800,000
2023	$3,000,000

Historic O&M expenditure included:

- Regulatory transmission assessments including the investigation and remediation of identified anomalies resulting from inline inspection and external corrosion direct assessment (ECDA).
- Sewer crossbore inspection program.
- Investigation and remediation of natural forces including landslides, flooding, erosion, etc.
- Buildover remediation where structures encroach into pipeline right-of-way.
- Remediation of difficult to operate valves.
- Maintenance of Integrity Risk model as a result of geographical and system changes.

These above costs do not reflect those related to ongoing maintenance of facilities including right-of-way clearing, patrols, leakage, cathodic protection, and other ongoing routine O&M work.

8 2024 Significant Safety Initiatives

8.1 Changes in TIMP Assessment Methodology

In 2024, NW Natural will extend the use of inline inspection (“ILI”) for integrity assessment of transmission pipelines assessed at seven-year intervals. Inline inspection tools have the advantage over direct assessment and pressure testing because they assess the entire

pipeline maintaining constant contact with the inner wall providing data allowing for the identification of interacting anomalies such as pipe deformation and metal loss. In 2024, NW Natural will change the assessment methodology of the following pipelines.

- S36 Mid-Willamette Valley Trans – Approximately 32-mile transmission pipeline that provides gas from the Newport LNG facility to communities in the Mid-Willamette Valley including Albany and Corvallis
- S24 Granger – Approximately 4.5 miles of transmission pipeline that supports the city of Albany.
- S22 Albany Trans – Approximately 12-mile transmission pipeline that initiates from a gate station east of Albany and is routed through Albany and supports the City of Corvallis and Oregon State University.

8.2 Pro-active EFV Installations

NW Natural has installed EFVs on all new single-family residential services since February of 1999. In 2006, Federal Code was modified to require the installation of EFVs on all new residential and small commercial services. NW Natural will continue and expand the program installing EFVs on existing residential and small commercial services when the buried portion of the service line is exposed and service to the customer is interrupted. NW Natural believes proactive installation of EFVs is a prudent and pragmatic approach that can mitigate the consequence of an excavation damage to a service line.

9 Transmission Material Verification

In compliance with recent Regulatory Mandates involving material verification of steel transmission pipelines, NW Natural has implemented a non-destructive material verification program to collect material property data on transmission pipeline assets. This program involves material testing of in-service pipelines during planned work to collect material data including metallurgy that was not required at the time of installation.

NW Natural has also developed a program to destructively test segments of pipeline that were removed from past transmission projects to collect the material property information. Collecting material information from the in-service transmission mains and the destructive tests from the historical transmission mains will allow NW Natural to develop a library of material property data.

10 Cost Benefit Analyses & Alternative Analysis

The performance of a cost benefit analysis and alternatives analysis is difficult in the context of safety programs mandated by regulation. As a result, a cost benefit analysis has not been a primary consideration in this report because these safety projects are mandated by CFR, dictated by industry best practices, or driven by operational requirements. The assigned risk and prioritization for implementing these projects are based on in-depth studies and analysis

of NW Natural's transmission and distribution systems as well as plant and storage assets. Studies performed as part of normal operations provide measurable and continual feedback needed to perform safety related work for which there are few practicable alternatives.

Alternative analysis and in-depth studies are useful when they identify threats and risks that can be mitigated or eliminated through the application of performance-based best practices, engineering analysis, operational knowledge, and subject matter experts. Where the Code of Federal Regulations prescribe compliance activity or mandate programs, the use of cost benefit, or alternative, analysis is not warranted.

When a pipeline safety initiative requires a cost benefit or alternative analysis, NW Natural may select a qualified external resource to perform the analysis.

11 Legislative Update

11.1 PHMSA Docket No. PHMSA-2013-0255

[Amdt. Nos. 192-130; 195-105] RIN 2137-AF06
Pipeline Safety: Requirement of Valve Installation and Minimum Rupture Detection Standards Published in April 2022 this rule revised requirements for the installation of rupture-mitigation valves (i.e., remote-control or automatic shut-off valves) or alternative equivalent technologies to prevent or mitigate the public safety and environmental consequences of pipeline ruptures. The rule also requires operators to contact 911 emergency call centers immediately upon notification of a potential rupture and conduct post-rupture investigations and reviews. Operators must also incorporate lessons learned from such investigations and reviews into training and qualifications programs, and in design, construction, testing, maintenance, operations, and emergency procedure manuals and specifications. NW Natural is in compliance with the rule at this time.

11.2 PHMSA Docket No. PHMSA-2011-0023

RIN 2137-AF38
Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments. This rule was published in November of 2021. At this time NW Natural does not operate gas gathering lines and is in compliance with the published rule.

11.3 PHMSA Rulemaking Docket No. PHMSA-2011-0023;

Amdt. No. 192-132] RIN 2137-AF39 Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments. PHMSA published this rule on August 24, 2022. NW Natural is in compliance with the rule as published.

11.4 Docket No. PHMSA-2016-0016 – Underground Storage Facilities for Natural Gas

On February 12, 2020, the Final Rule incorporating API Recommended Practice 1171 referred to as the Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs by reference was published. NW Natural developed a storage well integrity program in compliance with API 1171 incorporating all required provisions into operations at Mist. NW Natural program is in compliance with the final rule as published.

11.5 Docket No. PHSMA-2021-0039 Pipeline Safety NPRM: Gas Pipeline Leak Detection and Repair

On May 18, 2023, PHSMA issued a Notice of Proposed Rule Making: Gas Pipeline Leak Detection and Repair. The NPRM colloquially referred to as the LDAR rule is intended to reduce methane emissions from new and existing gas transmission and distribution pipelines, gas gathering pipelines, and underground natural gas storage facilities. NW Natural is reviewing the NPRM and will comply with the final rule when it is published in the Federal Register.

11.6 Docket No. PHSMA-2021-0046 Pipeline Safety NPRM: Safety of Gas Distribution Pipelines and Other Pipeline Safety Initiatives

On September 7, 2023, PHSMA issued a Notice of Proposed Rule Making: Safety of Gas Distribution Pipelines and Other Pipeline Safety Initiatives. PHMSA proposes revisions to the pipeline safety regulations to require operators of gas distribution pipelines to update their distribution integrity management programs (DIMP), emergency response plans, operations and maintenance manuals, and other safety practices. These proposals implement provisions of the Leonel Rondon Pipeline Safety Act—part of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020. NW Natural is reviewing the NPRM and will comply with the final rule when it is published in the Federal Register.

12 Completed Projects

Below is the list of projects scheduled to be completed in 4th quarter of 2022 and 2023.

12.1 Underground Storage – Well Integrity ($3.8MM – Actual)

This project involved the re-work and baseline assessments of four wells and reassessment of six wells in the Mist storage field. The 2024 project represents year seven of NW Natural's

well integrity baseline assessment work that includes down hole assessment of production casing and replacement of select tubulars, downhole equipment, and wellhead components. The reassessments include down hole assessment of production casing and replacement of select tubulars, downhole equipment, wellhead components, and/or mechanical integrity testing. The program was developed to meet compliance with PHMSA's adoption of APR RP 1171 - Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs. The baseline assessments represent a multiyear project planned for completion in 2025. The reassessment intervals are determined by risk assessment and information from the baseline assessments. This project has been completed.

12.2 McMinnville/Lafayette ILI (2023 actual $4.5M):

This project involves the transition of the McMinnville/Lafayette transmission line from ECDA to ILI assessment. The McMinnville/Lafayette transmission line is a 6" transmission main that connects to the Central Coast feeder near Amity, OR and runs north 13 miles to serve the residential and industrial customers of McMinnville. The transmission main terminates in the town of Lafayette north of McMinnville. Design work to modify the pipeline will begin in 2021 with construction starting in 2022; cleaning and ILI assessment, data analysis, and remediation activities will continue through the fall of 2022. This project has been completed.

12.3 North Eugene Industrial Trans (–2023 Actual $3.2M):

This project involves the transition of the North Eugene Industrial transmission line from ECDA to ILI assessment. The North Eugene Transmission line is a 5 mile long 6" and 8" transmission line primarily serving the residential and industrial customers located along the Randy Pape Beltline highway. The line terminates at the Northwest Expressway. Design and preliminary construction work coordinated with City of Eugene public works projects will be done in 2021. Cleaning and ILI assessment activities will continue through 2022 with data analysis and remediation/repairs completed in 2023. This project has been completed.

13 Conclusion

This SPP provides an overview of NW Natural's pipeline safety initiatives and commitment to the safe and reliable delivery of natural gas to the communities we serve. Through its more-than 164-year history, NW Natural has been committed to identifying threats to pipeline safety and taking steps to address and mitigate those threats. Looking forward to the role natural gas will play in our energy future, and as members of the communities we serve, NW Natural recognizes the trust placed on us by our neighbors and customers. NW Natural will continually work to ensure public safety and maintain the integrity of our natural gas system.

250 SW Taylor Street
Portland, OR 97204

503-226-4211
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September 30, 2022

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attention: Filing Center
201 High Street SE Suite 100
PO Box 1088
Salem, Oregon 97308-1088

Re: UM 1900: NW Natural's Annual Oregon Safety Project Plan in Compliance with OPUC Order No. 17-084

Northwest Natural Gas Company, dba NW Natural (NW Natural or Company), hereby submits its 2023 Safety Project Plan in compliance with Commission Order No. 17-084 entered March 6, 2017.

Please address correspondence on this matter to me with copies to the following:

eFiling
Rates & Regulatory Affairs
NW Natural
250 SW Taylor Street
Portland, Oregon 97204
Telephone: (503) 610-7330
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Sincerely,

/s/ Rebecca Trujillo

Rebecca Trujillo
Regulatory Consultant

Enclosure

NW Natural®

2023 SAFETY PROJECT PLAN

OREGON

September 30, 2022

250 SW Taylor Street
Portland, Oregon 97204
503-226-4211

NW Natural®

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NW Natural®

1. Introduction

In compliance with the Oregon Public Utility Commission ("Commission" or "OPUC") Order No 17-084 ("Order") in Docket UM 1722, this Safety Project Plan (SPP) outlines NW Natural's safety project investments for 2023. The SPP includes updated capital and O&M projects and programs and projects that carry over from 2022.

This SPP demonstrates NW Natural's commitment to pipeline safety by providing insight into NW Natural's safety activities and identifies NW Natural's response to regulatory changes that may drive safety program priorities or modify existing programs. In the future if NW Natural seeks approval for a Safety Cost Recovery Mechanism (SCRM), this SPP is intended to expedite the review process of safety investments.

Safety is a core value at NW Natural and we appreciate the opportunity to present this information to the Commission.

2. Background Information

NW Natural is a regulated natural gas utility conducting business in Oregon and southwest Washington. The Company serves ~780,000 customers and owns and operates ~660 miles of natural gas transmission pipeline, and ~14,200 miles of distribution pipelines. In addition, NW Natural operates three energy storage facilities in Oregon – Portland and Newport LNG Plants and Mist Underground Storage.

NW Natural's pipelines and storage facilities are governed by:

- 49 CFR Part 192 – Minimum Safety Standard – Transmission & Distribution Systems
- 49 CFR Part 193 – LNG Safety Standards
- 49 CFR Part 196 – Protection of Underground Pipelines from Excavations Activity
- Additional OARs (OAR 860-024 – Safety, OAR 860-031 – Pipeline Inspections), and ORSs such as ORS 757.039 – Regulation of hazardous substance distribution and storage operations, and ORS 757.542-993 – One call notification.

In addition to the federal and state regulations identified above, NW Natural's safety program considers the findings of Oregon House Resolution 3 (HR 3, 2011) which directed the Oregon Seismic Safety Policy Advisory Commission to prepare the Oregon Resiliency Plan with the purpose of identifying recommendations for how Oregon's critical energy infrastructures could be made seismically resilient against a Cascadia subduction zone earthquake. Upon completion of that work on February 28, 2013, the Oregon Senate passed Senate Bill 33 (SB 33, 2013), which established the Governor's Task Force on Oregon Resilience Plan ("ORP") Implementation ("Task Force"). In October 2014, the Task Force issued a report recommending that the Commission require regulated energy providers to conduct seismic assessments of regulated facilities and recommended that the Commission allow cost recovery for prudent

investments related to assessments and mitigation of vulnerabilities identified during those assessments. In October 2018, Governor Kate Brown presented the "Resiliency 2025" plan, titled "Improving Our Readiness for the Cascadia Earthquake and Tsunami" ("Resiliency 2025 Plan"). The Resiliency 2025 Plan follows the 2013 ORP, and outlines six key strategies for the State of Oregon. Its vision is to "protect all Oregonians by ensuring we are prepared to survive and recover from the expected 9.0 magnitude Cascadia earthquake and ensuing tsunami." The key strategy of the Resiliency 2025 Plan to improve the energy infrastructure is to "develop a plan for the Critical Energy Infrastructure Hub to prevent and mitigate catastrophic failure and ensure fuel supplies and alternate energy sources are available to responders and the public."

3. Threat Identification

NW Natural's four highest ranking threats, as identified in the DIMP Plan, are:

3.1 Excavation Damage

Excavation damage continues to be the principal threat to NW Natural's gas distribution system, comprising approximately 86 percent of all recorded leak repairs from 2010 to 2020. Excavation damage is a system-wide threat brought on predominantly by improper excavation practices. NW Natural's efforts to reduce excavation damages are described below.

3.1.1 Excavation Training and Education:

NW Natural actively engages in training and education for contractors, general public, and other utilities, to promote safe excavation procedures and practices. These efforts include classes on Oregon dig laws, displays at public events, and the use of media including print, radio, television, and internet to promote safety, best practices, and the use of 811.

NW Natural's Damage Prevention Department works to reduce the number of excavation damages through investigation, cause analysis, and proactively works to identify and support contractors engaging in high-risk construction activity.

3.1.2 One-Call Notification Practices:

NW Natural actively participates in local and state-level Utility Coordinating Councils as well as the One Call Utility Notification board. A primary function of these organizations is to reduce damages to underground utilities through excavation best practices, public awareness, and the use of the Oregon one call system (811).

NW Natural also maintains a robust Public Awareness Program which includes advertising, direct mailing, and public event outreach to increase this awareness.

3.1.3 Locating Practices:

NW Natural is an active member of Oregon's one call system and responds to all locate requests. Due to the high volume of locate requests, this work is contracted. All locating is performed by NW Natural qualified personnel and oversight is performed by Company contract management personnel. In addition, locating activity is included in NW Natural's Quality Assurance program to minimize the incidences of errors, mismarks, and missed due dates.

3.1.4 Incorrect Facility Marking:

Incorrectly marked facilities may be due to underground interference, equipment issues, inaccurate facility maps, or procedural issues. Locating personnel responsible for a mismark receive additional training and are required to re-qualify prior to being allowed to locate gas facilities. Review of mismarks are conducted by supervisor or other qualified personnel and the results are used to identify deficiencies, correct maps, and ensure the facility can be reliably located.

3.2 Material, Weld or Joint Failure

Material, weld, or joint failure is the second largest threat to the NW Natural gas distribution system, comprising approximately 9 percent of all recorded leak repairs from 2010 to 2020. NW Natural is proactive in its efforts to reduce these occurrences, as described below.

3.2.1 Plastic Pipe Installed from 1960s to 1980s:

NW Natural makes every effort to identify all pre-1982 plastic pipe installations, analyze leak histories, evaluate any conditions that may threaten integrity of the pipe, and take appropriate remedial action, including replacement, to mitigate risks to public safety.

3.2.2 Acrylonitrile-Butadiene-Styrene ("ABS"):

NW Natural used ABS in the 1960s to reline or renew existing steel services. These services have been identified for replacement. NW Natural's use of ABS was limited to ½" pipe inserted into existing steel service lines mitigating the industry-identified risk of rock impingement and slow crack growth related to unsuitable backfill material and construction practices.

3.2.3 Plexco Service Tee Celcon Caps:

NW Natural is aware of industry issues regarding Plexco Service Tee Celcon Caps possibly leaking when over-tightened during installation. These caps exist within the gas distribution system and are replaced as found and scheduled for replacement if leaks are identified.

3.2.4 Polyethylene ("PE") Fusion Failure:

NW Natural has a robust training and Quality Assurance/Quality Control program in place to ensure proper PE fusion quality. This program includes testing, biannual

qualification, and ongoing training. All PE fusions are visually inspected, and pressure tested prior to being placed in service.

3.2.5 Flat Back Risers:

In 2012, NW Natural identified a type of riser stop valve, internally known as a "Flat Back Riser," that contained components prone to atmospheric corrosion in the coastal areas of NW Natural's service territory. NW Natural identified that corrosion failure on a retaining pin could result in a hazardous leak. NW Natural developed an Accelerated Action Plan to replace these valves in coastal areas.

3.3 Corrosion

Corrosion is the third largest threat to the NW Natural's gas distribution system, comprising less than 2 percent of all recorded leak repairs from 2010 to 2020. NW Natural's efforts to reduce these occurrences are described below.

3.3.1 Pipe Replacement:

The primary driver for external corrosion system-wide is steel pipe. At this time, NW Natural's distribution system in Oregon is approximately 50% coated and cathodically protected steel and 50% polyethylene. During all pipe replacement projects, consideration is given to replacing existing steel pipes, valves, and fittings with polyethylene to mitigate the threat of corrosion. In 2015, NW Natural completed the replacement of all known un-coated bare steel pipe eliminating the single largest corrosion threat.

3.3.2 Pipe Casings:

Steel casings are primarily used to protect or facilitate the installation of mains and services underground and are fitted with seals to prevent water intrusion, spacers to prevent contact between the casing and gas carrying pipe, and vents.

NW Natural inspects steel casings annually to identify problems such as contact between the casing and gas pipe, or water intrusion. If a "short" or other anomaly is identified, a work order is created to address the concern.

At NW Natural, the installation of casings has been largely replaced by HDD (Horizontal Directional Drilling) installation. During pipeline improvement projects, existing casings are evaluated for replacement by HDD or alternatives.

3.3.3 Atmospheric Corrosion:

NW Natural's system includes facilities such as risers, regulators, station piping, bridge crossings and other above ground facilities that are susceptible to atmospheric corrosion.

NW Natural's atmospheric corrosion mitigation plan includes replacement of facilities when appropriate as well as protective coatings such as epoxies, paint, wax, other corrosion resistant materials, and enhanced inspections in locations with an elevated risk of corrosion.

3.3.4 Exposed Pipe Inspections

During normal operations when a buried pipeline is exposed, crews inspect the pipe and protective coating for evidence of corrosion or coating anomalies that can lead to future corrosion. Coating repairs or pipe replacements are completed before the pipe is backfilled and placed back in service.

3.4 Equipment Failure

Equipment Failure is the fourth largest threat to the NW Natural gas distribution system, comprising approximately 1 percent of all recorded leak repairs from 2010 to 2020. NW Natural's efforts to reduce these occurrences are described below.

3.4.1 Valves:

Valves are vital to the safe operation of a gas distribution system. NW Natural has in place a key operating valve inspection and maintenance program to ensure key valves are operable and available for use. Valves that are found to be inoperable, inaccessible, and/or paved over are identified and remediated as necessary.

3.4.2 Pressure Control / Relief Equipment:

NW Natural has an established inspection and maintenance program in place for pressure control/relief equipment to ensure reliable and safe operation.

3.4.3 Mechanical Couplings:

Pipe may pull out from compression couplings due to tensile forces including excavation damage, cyclic fatigue from changes in the temperature of natural gas as a result of the Joule-Thomson effect, ground movement from earthquakes or after heavy rains. Mechanical fitting failures are investigated, tracked, and reported per PHMSA and OPUC requirements.

In the past as an alternative to welding small diameter steel fittings, mechanical couplings were sometimes used to install valves and service tees. These types of fittings may develop leaks through the elastomer seal between the coupling and the pipe. NW Natural replaces these fittings with welded steel fittings or polyethylene as discovered during routine operations and maintenance activity.

3.4.4 Other:

Other types of material or equipment failure may occur in the gas distribution system. Failure reports are reviewed to detect trends or patterns that may affect the distribution system.

Many of the safety projects identified in this plan are in direct response to the above threats, and to maintain compliance with safety codes and regulations.

4. Safety Activities Performed by NW Natural

Safety activities at NW Natural can be divided into categories:

4.1 Prescriptive Regulatory Actions – Includes actions which must be performed to meet minimum federal safety standards.

49 CFR 192 includes multiple prescriptive activities, intended to safeguard public safety, and fall into broad categories such as “operations” (Subpart L) and “maintenance” (Subpart M). Most of these activities require inspections at prescribed intervals to confirm that a facility or asset is meeting operational requirements prescribed by federal code. These activities provide the baseline data for other performance-based activities and include, but are not limited to:

- Atmospheric corrosion surveys
- Leakage surveys
- Cathodic protection surveys
- Right of way (“ROW”) patrols
- Valve maintenance
- Water crossing inspections
- Odorization
- Odorometer Reads

- Line Marking
- Pressure Regulation Inspection
- Large Meter Inspections
- Record Keeping
- Control Room Management
- Bridgeline Inspections
- Equipment Calibration
- Houseboat Inspections
- Transmission Integrity

The safety activities from this category are prescriptive in nature and are not driven by risk analysis alone. Because these activities are required, they are not discussed further in this SPP, which instead focuses on projects and/or programs identified by NW Natural as essential to enhancing safety and reliability.

4.1.1 Transmission Integrity (TIMP)

Transmission Integrity refers to 49 CFR 192 Subpart O- Transmission Integrity Management Program ("TIMP"). This federally mandated program covers natural gas transmission pipelines located in High Consequence Areas (HCA) and Moderate Consequence Areas (MCA). NW Natural exceeds code requirements in TIMP to address conditions outside of HCAs and MCAs.

Activities in this category include baseline assessments and reassessments of transmission lines using in-line inspection ("ILI") and other direct assessment methods. They may also include pipeline replacements and modifications in compliance with integrity management rules, best practices, and relocation of facilities to mitigate threats posed by natural forces such as flooding, land movement, and erosion.

4.2 Proactive, Performance-Based Actions

Other sections of 49 CFR 192 include more proactive performance-based risk reduction activities, such as Subpart P – Distribution Integrity Management Program ("DIMP"), Damage Prevention, and Public Awareness.

4.2.1 Distribution Integrity (DIMP)

Distribution Integrity is outlined in 49 CFR 192 Subpart P- Gas Distribution Pipeline Integrity Management. This federally mandated program requires operators to create a written Integrity Management Program that takes into consideration: system knowledge, threat identification, evaluation and risk ranking, identification, and implementation of measures to address risk, measurement of results, and reporting.

Activities in this category include projects warranting Accelerated Action ("AA") to address a system integrity risk. These AA projects are identified through risk modeling, industry identified threats, and by subject matter experts within the Company, and include:

- Replacement of vintage plastic services,
- Relocation of facilities under structures,
- Replacement of valves and fittings susceptible to leakage,
- Protection of above grade gas facilities,
- Crossbore investigation, and
- Relocation of distribution gas lines to mitigate threats posed by natural forces such as:
  - Flooding
  - Land movement, and
  - Erosion.
- Enhanced electronic flow valve ("EFV") Installation – installation of EFVs on services that were installed prior to the EFV rule issued in 2006
- Dithiazine – a sulfur compound found in natural gas that has been known to cause equipment failure especially in district regulators.

4.3 Safety Policy and Practices

NW Natural also implements risk reduction activities not explicitly required by the federal code. These actions have been identified as prudent safety practices intended to enhance public safety, improve system reliability, and maintain the safe operation of NW Natural's above- and below-ground facilities including LNG Plants and underground natural gas storage facilities. These risk reduction actions include:

- Seismic vulnerability assessments of LNG Plants, the Mist Underground Storage Facility, and Transmission Pipeline System as recommended by SB 33 (2013) and consistent with the Governor's Resiliency 2025 Plan
- Accelerated replacement of vintage materials
- Transmission inspection outside of HCAs and MCAs.
- Development of a PSMS (Pipeline Safety Management System)
- Proactive EFV installation
- Locate ticket risk modeling
- Natural forces assessments of NW Natural's transmission system as part of NW Natural patrol and surveillance programs.

5. Projected and Preliminary Costs Presented in this Plan

The 2023 Capital and O&M costs presented in this plan are projected based on current expenditures for each of the identified projects through the end of the year. Costs presented for the significant safety initiatives are preliminary for planning purposes and do not include NW Natural overhead costs. Costs for safety projects under consideration will be presented in future SPPs.

6. 2023 Capital Safety Investment

In 2023, NW Natural estimates it will invest $8.4 MM in capital to comply with DIMP, TIMP, and other regulations. Significant projects in this category include:

6.1 SP Newsprint ILI (2022-23 estimate $1.5MM):

This project involves transition of the SP Newsprint transmission line from direct assessment to ILI. The SP Newsprint transmission line is a 7-mile transmission pipeline that supports the City of Newberg and Dundee. This is a dual diameter pipeline (12" & 16") which initiates at the south end of Sherwood and is routed along Hwy 99W where it terminates at the former site of SP Newsprint. Work on this project will begin in 2022 with planned completion in the fall of 2023.

6.2 Pro-active EFV Installations (2023 estimate $1MM):

On October 14, 2016, the U.S. Department of Transportation's ("DOT's") Pipeline and Hazardous Materials Safety Administration ("PHMSA") adopted code requiring the installation of EFVs or shut-off valves on all new or replaced branched service lines (Docket No. PHMSA-2011-009). While the code requires EFV installations be installed in all new or replaced branched service lines, it did not require retrofitting EFVs on existing services.

NW Natural believes a proactive EFV installation program is a prudent action that can mitigate the consequence of a gas release resulting from excavation damage to a gas service line. NW Natural is implementing a policy to retrofit EFVs on existing gas service lines when the buried portion of the service line is exposed and the work involves the interruption of gas service.

This pro-active EFV program was initiated in 2020 and will continue to be a safety program.

6.3 Underground Storage – Well Integrity (2023 estimate $3.3MM)

On December 19, 2016, PHMSA issued an interim final rule (IFR) establishing regulations for underground natural gas storage facilities (UNGSF). The IFR incorporated by reference American Petroleum Institute ("API") Recommended Practice ("RP") 1171, "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs" (First Edition, September 2015). The IFR implemented PHMSA's authority to regulate underground gas storage and the Congressional mandate in section 12 of the PIPES Act to establish minimum safety standards.

The final rule published on February 12, 2020 modified compliance timelines, clarified regulatory roles, reduced recordkeeping and reporting requirements, and formalized integrity management practices. In accordance with the final rule, NW Natural is running baseline casing inspection logs on each of its active gas storage wells prior to the March 13, 2027 deadline.

Work in 2023 will involve assessments of the production casings of four storage wells. The assessments will include downhole wireline logging of the production casing strings using both multi-arm caliper and magnetic flux tools to identify deformations and metal loss features.

6.4 Other safety projects and programs (2023 estimate $2.9MM):

Pipeline Replacement due to Seismic/Natural Forces

Portions of NW Natural's distribution and transmission system cross through landslide faults, seismic faults, sensitive areas, and waterways. Due to significant weather events or the passage of time, the integrity of these pipelines may become at risk. When identified during patrols, routine maintenance, or other stakeholders, the Integrity Team develops plans to remediate these at-risk pipelines as they are identified.

Valve Isolation Plans

NW Natural is working to develop a strategy for identifying and installing additional valves in the distribution system to assist in the isolation of portions of the distribution system in case of an emergency or third-party damage.

Meter Protection Installation

NW Natural will continue installation of guard posts adjacent to meter sets that are determined to be at risk of damage due to vehicle or equipment contact.

Pipeline Modification due to ROW Encroachment

Patrols of NW Natural Pipelines may discover structures or other encroachments built over or adjacent to pipelines that can impact the safe operation of or access to a pipeline. This program works with landowners to remediate these encroachments.

Pipeline Material Identification (PMI)

At selected transmission pipeline anomaly remediation sites, NW Natural has instituted a process using technology to non-destructively test and acquire data regarding pipe material properties. In addition, when the Transmission Integrity rule went into effect over twenty years ago, NW Natural began keeping short (18"-24" long) sections of pipe for future reference. These spools will be destructively tested to obtain pipe material properties that were not required as part of the original installation documentation. The material data obtained through this program will be stored in the permanent record for each pipe segment.

6.5 ASV/RCV Installation (2023 estimate $500,000)

To assist in the timely and efficient closure of valves on the transmission system, NW Natural is continually identifying locations where ASV/RCV valves can reasonably be installed, or existing valves retrofitted, in order to facilitate isolation of the transmission system.

6.6 Historical Capital Expenditure - Safety Project Plan (System Integrity)

The Historical Capital Expenditures below are actual expenditures for each of the presented years.

Year	Expenditure
2015	$ 17,190,356*
2016	$ 7,772,763
2017	$ 5,925,409
2018	$ 9,699,814
2019	$ 10,231,431
2020	$ 8,900,000
2021	$ 8,200,000
2022	$ 9,000,000

*Final year of known bare steel main replacement

Historical capital expenditures include:

- Work to modify pipelines to accept inline inspection devices, including removal or replacement of non-piggable fittings and facilities required to launch and receive inline inspection devices.
- Pipeline relocation to mitigate threats including outside forces and natural forces. This work does not include relocations due to utility conflicts, or third-party improvement projects.
- Pipe replacements and testing in compliance with federal and state regulations.
- Ongoing DIMP AA programs/projects such as Vintage Plastic, Guardpost installations, Proactive EFV installations, etc.

7. 2023 O&M Expenditures

In 2023 NW Natural expects to spend $4.95MM in O&M to address and comply with DIMP, TIMP, damage prevention, and public awareness.

Activities that reflect expenditures in this category include costs for supplies (office/field), reference materials, education (conferences/workshops), vendor and contract costs associated with transmission assessments, sewer crossbore investigations and remediation, public awareness program materials, advertisements and mailings, and natural forces investigation and remediation. Additionally, this category covers the development, initiation, and execution of studies and consulting fees related to integrity requirements, such as class location studies and third-party geotechnical site evaluations to address and mitigate risk.

O&M also includes some non-capital internal labor in support of NW Natural's system integrity program ("SIP"). These costs include the Integrity Management staff (7 FTE), damage

prevention specialists (4 FTEs) involved in damage prevention/investigation, and a public information officer for safety outreach, training, and program administration. The Integrity Management group may also utilize other internal resources in support of SIP activities which includes GIS analysts, Customer Service, Construction, and other subject matter experts. Significant O&M projects include:

7.1 Sewer Crossbore Inspections (2023 estimate $1.4MM):

The sewer crossbore program involves the visual inspection of sanitary sewers for incidences of gas line crossbores. In installations where trenchless technology was used to install polyethylene pipe, there exists the possibility the gas line was bored through a sewer main or lateral. NW Natural's policy is to expose all foreign line crossings when performing trenchless work. Sewer crossbores typically occur when facility owners fail to locate their pipe, creating a situation where NW Natural is unable to expose facilities during construction. This is an industry-wide threat. Although sewer crossbores are not isolated to gas operators, the consequence when gas lines are involved can be high. This program identifies existing trenchless polyethylene installations and inspects the sewers in the vicinity to identify crossbores.

7.2 Transmission Inline and Direct Assessment Reassessment and Remediation (2023 estimate $1.3MM):

This work includes the federally prescribed seven-year reassessment of transmission pipelines in HCAs and is comprised of both inline inspection and direct assessment of transmission assets and associated repairs.

7.3 Natural Forces (2023 estimate $300,000):

Where the threat of natural forces can be mitigated without pipe replacement or rerouting, NW Natural may choose to address the threat through site work. This option is necessary in situations where a reroute is not feasible due to environmental restrictions or where a pipeline serves a critical customer or provides a single feed to a distribution system. Work may include armoring of slopes, re-grading of sites, culvert improvements, and retaining structures to address land movement and drainage issues.

7.4 Damage Prevention (2023 estimate $800,000):

In compliance with DIMP regulations, and to address the single largest threat to gas facilities, NW Natural maintains a damage prevention department. The department consists of a supervisor and 4 FTE damage prevention specialists whose responsibilities include damage prevention through high risk locate ticket intervention, training, attendance at pre-construction meetings, participation in Utility Coordinating Councils, and support of the 811 One-call system. Damage prevention specialists are also responsible for the investigation, enforcement, and contractor training related to excavation and third-party damage.

7.5 Public Awareness (2023 estimate $1,050,000):

NW Natural's Public Awareness program meets the requirements mandated in API RP 1162, adopted by reference by PHMSA into Part 192.616(a), (b), and (c). This program promotes public safety through communication and outreach focused on educating customers and the public about natural gas safety. The program includes customer correspondence, mailers, advertisements, community events, mobile phone applications, and brochures to excavators, contractors, public officials, residences and businesses along pipeline rights-of-way and in high consequence areas, floating homes, and schools.

The Public Awareness Plan utilizes television and radio advertising, bill inserts, social media, and events to promote natural gas safety awareness. Targeted outreach and public awareness materials are provided annually to customers near transmission pipelines, as well as contractors, excavators, and first responders within NW Natural's service territory.

7.6 Right-of-Way Encroachments (2023 estimate $100,000):

Pipeline patrols are used to identify changes in site conditions. An example of such a change is the installation of structures over pipelines, and inside dedicated pipeline rights-of-way, or easements. In some instances, the remediation may involve the relocation of structures and other non-gas facilities.

7.7 Historical O&M Expenditure - Safety Project Plan (System Integrity):

The historical O&M expenditures below are actual expenditures for each of the presented years (not including PSMS, damage prevention or public awareness expenditures).

Year	Expenditure
2015	$4,034,218
2016	$4,889,618
2017	$4,771,267
2018	$4,000,000
2019	$3,052,000
2020	$3,100,000
2021	$2,900,000
2022	$2,800,000

Historic O&M expenditure included:

- Regulatory transmission assessments including the investigation and remediation of identified anomalies resulting from inline inspection and external corrosion direct assessment (ECDA).
- Sewer crossbore inspection program.
- Investigation and remediation of natural forces including landslides, flooding, erosion, etc.
- Buildover remediation where structures encroach into pipeline right-of-way.
- Remediation of difficult to operate valves.

- Maintenance of Integrity Risk model as a result of geographical and system changes.

These above costs do not reflect those related to ongoing maintenance of facilities including right-of-way clearing, patrols, leakage, cathodic protection, and other ongoing routine O&M work.

8. 2023 Significant Safety Initiatives

8.1 Changes in TIMP Assessment Methodology

In 2023, NW Natural will extend the use of inline inspection (ILI) for integrity assessment of transmission pipelines assessed at seven-year intervals. Inline inspection tools have the advantage over direct assessment and pressure testing because they assess the entire pipeline maintaining constant contact with the inner wall providing data allowing for the identification of interacting anomalies such as pipe deformation and metal loss. In 2023, NW Natural will change the assessment methodology of the following pipelines.

The SP Newsprint transmission pipeline supporting the City of Newberg, Dundee and surrounding areas. The 7-mile long pipeline is routed along Oregon Highway 99W.

8.2 Pro-active EFV Installations

NW Natural has installed EFVs on all new single-family residential services since February of 1999. In 2006, Federal Code was modified to require the installation of EFVs on all new residential and small commercial services. NW Natural will continue and expand the program installing EFVs on existing residential and small commercial services when the buried portion of the service line is exposed and service to the customer is interrupted. NW Natural believes proactive installation of EFVs is a prudent and pragmatic approach that can mitigate the consequence of an excavation damage to a service line.

9. Transmission Material Verification

In compliance with recent regulatory mandates involving material verification of steel transmission pipelines, NW Natural has implemented a non-destructive material verification program to collect material property data on transmission pipeline assets. This program involves material testing of in-service pipelines during planned work to collect material data including metallurgy that was not required at the time of installation.

NW Natural has also developed a program to destructively test segments of pipeline that were removed from past transmission projects to collect the material property information. Collecting material information from the in-service transmission mains and the destructive tests from the historical transmission mains will allow NW Natural to develop a library of material property data.

10. Cost Benefit Analyses & Alternative Analysis

The performance of a cost benefit analysis and alternatives analysis is difficult in the context of safety programs mandated by regulation. As a result, a cost benefit analysis has not been a primary consideration in this report because these safety projects are mandated by CFR, dictated by industry best practices, or driven by operational requirements. The assigned risk and prioritization for implementing these projects are based on in-depth studies and analysis of NW Natural's transmission and distribution systems as well as plant and storage assets. Studies performed as part of normal operations provide measurable and continual feedback needed to perform safety related work for which there are few practicable alternatives.

Alternative analysis and in-depth studies are useful when they identify threats and risks that can be mitigated or eliminated through the application of performance-based best practices, engineering analysis, operational knowledge, and subject matter experts. Where the Code of Federal Regulations prescribe compliance activity or mandate programs, the use of cost benefit, or alternative, analysis is not warranted.

When a pipeline safety initiative requires a cost benefit or alternative analysis, NW Natural may select a qualified external resource to perform the analysis.

11. Legislative Update

11.1 PHMSA Docket No. PHMSA-2013-0255

[Amdt. Nos. 192-130; 195-105] RIN 2137-AF06
Pipeline Safety: Requirement of Valve Installation and Minimum Rupture Detection Standards. This rule was published in April 2022. It revises requirements for the installation of rupture-mitigation valves (i.e., remote-control or automatic shut-off valves) or alternative equivalent technologies to prevent or mitigate the public safety and environmental consequences of pipeline ruptures. The rule also requires operators to contact 911 emergency call centers immediately upon notification of a potential rupture and conduct post-rupture investigations and reviews. Operators must also incorporate lessons learned from such investigations and reviews into training and qualifications programs, and in design, construction, testing, maintenance, operations, and emergency procedure manuals and specifications. NW Natural is in compliance with the rule at this time.

11.2 PHMSA Docket No. PHMSA-2011-0023

RIN 2137-AF38
Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments. This rule was published in November of 2021. At this time, NW Natural does not operate gas gathering lines.

11.3 PHMSA Rulemaking Docket No. PHMSA-2011-0023

[Amdt. No. 192-132] RIN 2137-AF39
Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments. PHMSA published this rule on August 24, 2022. The effective date of the final rule is nine months after date of publication in the Federal Register. NW Natural is currently evaluating the rulemaking and anticipates updates to standards and procedures to document compliance with the rulemaking.

11.4 Docket No. PHMSA-2016-0016 – Underground Storage Facilities for Natural Gas

On February 12, 2020, the Final Rule incorporating API Recommended Practice 1171 referred to as the Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs by reference was published. NW Natural developed a storage well integrity program in compliance with API 1171 incorporating all required provisions into operations at Mist. NW Natural program is in compliance with the final rule as published.

12. Completed Projects

Below is the list of projects completed in 4th quarter of 2021 or 2022 or expected to be completed in the 4th quarter of 2022.

12.1 Springfield Transmission (ILI) (2022 estimate $1MM):

This project involves transition of the Springfield transmission line from direct assessment to ILI. The Springfield transmission line is the primary feed to downtown Springfield and large industrial customers in the area. This pipeline is approximately three miles and routed along Harlow Road, which is a major thoroughfare between the cities of Eugene and Springfield. Work on this project has a planned completion in the fall of 2022.

12.2 Underground Storage - Well Integrity ($3.3MM – Actual):

This project involved the re-work and baseline assessment of five wells in the Mist storage field. The 2022 project represents year four of NW Natural's well integrity baseline assessment work that includes down hole assessment of production casing and replacement of select tubulars, downhole equipment, and wellhead components. The program was developed to meet compliance with PHMSA's adoption of APR RP 1171 - Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs. This is a multiyear project planned for completion in 2027.

12.3 South Eugene Transmission (ILI) ($2.0MM - Actual):

This project involved transition of the South Eugene transmission line from direct assessment to ILI. The South Eugene transmission line is a transmission line from the South Eugene gate that primarily serves the IP Springfield facility and is approximately 6.5 miles in length. Work including station upgrades was completed in 2021. The ILI assessment and remediation of any identified anomalies was completed in 2022.

12.4 McMinnville/Lafayette ILI (2022 Estimate $3MM):

This project involves the transition of the McMinnville/Lafayette transmission line from ECDA to ILI assessment. The McMinnville/Lafayette transmission line is a 6" transmission main that connects to the Central Coast feeder near Amity, OR and runs north 13 miles to serve the residential and industrial customers of McMinnville. The transmission main terminates in the town of Lafayette north of McMinnville. Design work to modify the pipeline will begin in 2021 with construction starting in 2022; cleaning and ILI assessment, data analysis, and remediation activities will continue through the fall of 2022.

12.5 North Eugene Industrial Trans (2022 Estimate $2.1M):

This project involves the transition of the North Eugene Industrial transmission line from ECDA to ILI assessment. The North Eugene Transmission line is a 5 mile long 6" and 8" transmission line primarily serving the residential and industrial customers located along the Randy Pape Beltline highway. The line terminates at the Northwest Expressway. Design and preliminary construction work coordinated with City of Eugene public works projects was completed in 2021. Cleaning and ILI assessment activities will continue through 2022 with data analysis and remediation/repairs completed in 2023.

13. Conclusion

This SPP provides an overview of NW Natural's pipeline safety initiatives and commitment to the safe and reliable delivery of natural gas to the communities we serve. Through its more-than 160-year history, NW Natural has been committed to identifying threats to pipeline safety and taking steps to address and mitigate those threats. Looking forward to the role natural gas will play in our energy future, and as members of the communities we serve, NW Natural recognizes the trust placed on us by our neighbors and customers. NW Natural will continually work to ensure public safety and maintain the integrity of our natural gas system.

NW Natural®

2022 SAFETY PROJECT PLAN

OREGON

September 30, 2021

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Portland, Oregon 97204
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NW Natural®

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NW Natural®

1. Introduction

In compliance with the Oregon Public Utility Commission ("Commission" or "OPUC") Order No 17-084 ("Order") in Docket UM 1722, this 2021 Safety Project Plan (SPP) outlines NW Natural's safety project investments for 2022. The SPP includes updated capital and O&M projects and programs and projects that carry over from 2021.

This SPP demonstrates NW Natural's commitment to pipeline safety by providing insight into NW Natural's safety activities and identifies NW Natural's response to regulatory changes that may drive safety program priorities or modify existing programs. In the future if NW Natural seeks approval for a Safety Cost Recovery Mechanism (SCRM), this SPP is intended to expedite the review process of safety investments.

Safety is a core value at NW Natural and we appreciate the opportunity to present this information to the Commission.

2. Background Information

NW Natural is a regulated natural gas utility conducting business in Oregon and southwest Washington. The Company serves ~770,000 customers and owns and operates ~660 miles of natural gas transmission pipeline, and ~14,000 miles of distribution pipelines. In addition, NW Natural operates three energy storage facilities in Oregon – Portland and Newport LNG Plants and Mist Underground Storage.

NW Natural's pipelines and storage facilities are governed by:

- 49 CFR Part 192 – Minimum Safety Standard – Transmission & Distribution Systems
- 49 CFR Part 193 – LNG Safety Standards
- 49 CFR Part 196 – Protection of Underground Pipelines from Excavations Activity
- Additional OARs (OAR 860-024 – Safety, OAR 860-031 – Pipeline Inspections), and ORSs such as ORS 757.039 – Regulation of hazardous substance distribution and storage operations, and ORS 757.542-993 – One call notification.

In addition to the federal and state regulations identified above, NW Natural's safety program considers the findings of Oregon House Resolution 3 (HR 3, 2011) which directed the Oregon Seismic Safety Policy Advisory Commission to prepare the Oregon Resiliency Plan with the purpose of identifying recommendations for how Oregon's critical energy infrastructures could be made seismically resilient against a Cascadia subduction zone earthquake. Upon completion of that work on February 28, 2013, the Oregon Senate passed Senate Bill 33 (SB 33, 2013), which established the Governor's Task Force on Resilience Plan Implementation ("Task Force"). In October 2014, the Task Force issued a report recommending that the Commission require regulated energy providers to conduct seismic assessments of regulated facilities and recommended that the Commission allow cost recovery for prudent investments related to

assessments and mitigation of vulnerabilities identified during those assessments. In October 2018, Governor Kate Brown presented the "Resiliency 2025" plan, titled "Improving Our Readiness for the Cascadia Earthquake and Tsunami" ("Resiliency 2025 Plan"). The Resiliency 2025 Plan follows the 2013 ORP, and outlines six key strategies for the State of Oregon. Its vision is to "protect all Oregonians by ensuring we are prepared to survive and recover from the expected 9.0 magnitude Cascadia earthquake and ensuing tsunami." The key strategy of the Resiliency 2025 Plan to improve the energy infrastructure is to "develop a plan for the Critical Energy Infrastructure Hub to prevent and mitigate catastrophic failure and ensure fuel supplies and alternate energy sources are available to responders and the public."

3. Threat Identification – NW Natural's four highest ranking threats, as identified in the DIMP Plan are:

3.1 Excavation Damage

Excavation damage continues to be the principal threat to NW Natural's gas distribution system, comprising approximately 86 percent of all recorded leak repairs. Excavation damage is a system-wide threat brought on predominantly by improper excavation practices. NW Natural's efforts to reduce excavation damages are described below.

3.1.1 Excavation Training and Education:

NW Natural actively engages in training and education for contractors, general public, and other utilities, to promote safe excavation procedures and practices. These efforts include classes on Oregon dig laws, displays at public events, and the use of media including print, radio, television, and internet to promote safety, best practices, and the use of 811.

NW Natural's Damage Prevention Department works to reduce the number of excavation damages through investigation, cause analysis, and proactively works to identify and support contractors engaging in high-risk construction activity.

3.1.2 One-Call Notification Practices:

NW Natural actively participates in local and state-level Utility Coordinating Councils as well as the One Call Utility Notification board. A primary function of these organizations is to reduce damages to underground utilities through excavation best practices, public awareness, and the use of the Oregon one call system (811).

NW Natural also maintains a robust Public Awareness Program which includes advertising, direct mailing, and public event outreach to increase this awareness.

3.1.3 Locating Practices:

NW Natural is an active member of Oregon's one call system and responds to all locate requests. Due to the high volume of locate requests this work is contracted. All locating

is performed by NW Natural qualified personnel and oversight is performed by Company contract management personnel. In addition, locating activity is included in NW Natural's Quality Assurance program to minimize the incidences of errors, mismarks, and missed due dates.

3.1.4 Incorrect Facility Marking:

Incorrectly marked facilities may be due to underground interference, equipment issues, inaccurate facility maps, or procedural issues. Locating personnel responsible for a mismark receive additional training and are required to re-qualify prior to being allowed to locate gas facilities. Review of mismarks are conducted by supervisor or other qualified personnel and the results are used to identify deficiencies, correct maps, and ensure the facility can be reliably located.

3.2 Material, Weld or Joint Failure

Material, weld, or joint failure is the second largest threat to the NW Natural gas distribution system, comprising approximately 9 percent of all recorded leak repairs. NW Natural is proactive in its efforts to reduce these occurrences, as described below.

3.2.1 Plastic Pipe Installed from 1960s to 1980s:

NW Natural makes every effort to identify all pre-1982 plastic pipe installations, analyze leak histories, evaluate any conditions that may threaten integrity of the pipe, and take appropriate remedial action, including replacement, to mitigate risks to public safety.

3.2.2 Acrylonitrile-Butadiene-Styrene ("ABS"):

NW Natural used ABS in the 1960s to reline or renew existing steel services. These services have been identified for replacement. NW Natural's use of ABS was limited to ½" pipe inserted into existing steel service lines mitigating the industry-identified risk of rock impingement and slow crack growth related to unsuitable backfill material and construction practices.

3.2.3 Plexco Service Tee Celcon Caps:

NW Natural is aware of industry issues regarding Plexco Service Tee Celcon Caps possibly leaking when over-tightened during installation. These caps exist within the gas distribution system and are replaced as found and scheduled for replacement if leaks are identified.

3.2.4 Polyethylene ("PE") Fusion Failure:

NW Natural has a robust training and Quality Assurance/Quality Control program in place to ensure proper PE fusion quality. This program includes testing, biannual qualification, and ongoing training. All PE fusions are visually inspected, and pressure tested prior to being placed in service.

3.2.5 Flat Back Risers:

In 2012 NW Natural identified a type of riser stop valve, internally known as a "Flat Back Riser" that contained components prone to atmospheric corrosion in the coastal areas of NW Natural's service territory. NW Natural identified that corrosion failure on a retaining pin could result in a hazardous leak. NW Natural developed an Accelerated Action Plan to replace these valves in coastal areas.

3.3 Corrosion

Corrosion is the third largest threat to the NW Natural's gas distribution system, comprising less than 2 percent of all recorded leak repairs. NW Natural's efforts to reduce these occurrences are described below.

3.3.1 Pipe Replacement:

The primary driver for external corrosion system-wide is steel pipe. At this time NW Natural's distribution system is approximately 51% coated and cathodically protected steel and 49% polyethylene. During all pipe replacement projects consideration is given to replacing existing steel pipes, valves, and fittings with polyethylene to mitigate the threat of corrosion. In 2015 NW Natural completed the replacement of all known un-coated bare steel buried pipe eliminating the single largest corrosion threat.

3.3.2 Pipe Casings:

Steel casings are primarily used to protect or facilitate the installation of mains and services underground and are fitted with seals to prevent water intrusion, spacers to prevent contact between the casing and gas carrying pipe, and vents.

NW Natural inspects steel casings annually to identify problems such as contact between the casing and gas pipe, or water intrusion. If a "short" or other anomaly is identified a work order is created to address the concern.

At NW Natural the installation of casings has been largely replaced by HDD (Horizontal Directional Drilling) installation. During pipeline improvement projects existing casings are evaluated for replacement by HDD or alternatives.

3.3.3 Atmospheric Corrosion:

NW Natural's system includes facilities such as risers, regulators, station piping, bridge crossings and other above ground facilities that are susceptible to atmospheric corrosion.

NW Natural's atmospheric corrosion mitigation plan includes replacement of facilities when appropriate as well as protective coatings such as epoxies, paint, wax, other corrosion resistant materials, and enhanced inspections in locations with an elevated risk of corrosion.

3.3.4 Exposed Pipe Inspections

During normal operations when a buried pipeline is exposed crews inspect the pipe and protective coating for evidence of corrosion, or coating anomalies that can lead to future corrosion. Coating repairs or pipe replacements are completed before the pipe backfilled and placed back in service.

3.4 Equipment Failure

Equipment Failure is the fourth largest threat to the NW Natural gas distribution system, comprising approximately 1 percent of all recorded leak repairs. NW Natural's efforts to reduce these occurrences are described below.

3.4.1 Valves:

Valves are vital to the safe operation of a gas distribution system. NW Natural has in place a key operating valve inspection and maintenance program to ensure key valves are operable and available for use. Valves that are found to be inoperable, inaccessible, and/or paved over are identified and remediated as necessary.

3.4.2 Pressure Control / Relief Equipment:

NW Natural has an established inspection and maintenance program in place for pressure control/relief equipment to ensure reliable and safe operation.

3.4.3 Mechanical Couplings:

Pipe may pull out from compression couplings due to tensile forces including excavation damage, cyclic fatigue from changes in the temperature of natural gas as a result of the Joule-Thomson effect, ground movement from earthquakes or after heavy rains. Mechanical fitting failures are investigated, tracked, and reported per PHMSA and OPUC requirements.

In the past as an alternative to welding small diameter steel fittings mechanical couplings were sometimes used to install valves and service tees. These types of fittings may develop leaks through the elastomer seal between the coupling and the pipe. NW Natural replaces these fittings with welded steel fittings or polyethylene as discovered during routine operations and maintenance activity.

3.4.4 Other:

Other types of material or equipment failure may occur in the gas distribution system. Failure reports are reviewed to detect trends or patterns that may affect the distribution system.

Many of the safety projects identified in this plan are in direct response to the above threats, and to maintain compliance with safety codes and regulations.

4. Safety Activities Performed by NW Natural

Safety activities at NW Natural can be divided into categories:

4.1 Prescriptive Regulatory Actions – Includes actions which must be performed to meet minimum federal safety standards.

49 CFR 192 includes multiple prescriptive activities, intended to safeguard public safety, and fall into broad categories such as “operations” (Subpart L) and “maintenance” (Subpart M). Most of these activities require inspections at prescribed intervals to confirm that a facility or asset is meeting operational requirements prescribed by federal code. These activities provide the baseline data for other performance-based activities and include, but are not limited to:

- Atmospheric corrosion surveys
- Leakage surveys
- Cathodic protection surveys
- Right of way (“ROW”) patrols
- Valve maintenance
- Water crossing inspections
- Odorization
- Odorometer Reads
- Line Marking

- Pressure Regulation Inspection
- Large Meter Inspections
- Record Keeping
- Control Room Management
- Bridgeline Inspections
- Equipment Calibration
- Houseboat Inspections
- Transmission Integrity

The safety activities from this category are prescriptive in nature and are not driven by risk analysis alone. Because these activities are required, they are not discussed further in this SPP, which instead focuses on projects and/or programs identified by NW Natural as essential to enhancing safety and reliability.

4.2 Proactive, Performance-Based Actions

Other sections of 49 CFR 192 include more proactive performance-based risk reduction activities, such as Subpart O – Transmission Integrity Management Program ("TIMP") and Subpart P – Distribution Integrity Management Program ("DIMP"), Damage Prevention, and Public Awareness. These programs focus on mitigating pipeline safety risk.

4.2.1 Transmission Integrity (TIMP)

Transmission Integrity refers to 49 CFR 192 Subpart O-Gas Transmission Pipeline Integrity Management. This federally mandated program covers natural gas transmission pipelines located in High Consequence (HCA) and Moderate Consequence (MCA) areas. NW Natural exceeds code requirements in TIMP to address conditions outside of HCA and MCA's

Activities in this category include baseline assessments and reassessments of transmission lines using in-line inspection ("ILI") and other direct assessment methods. They may also include pipeline replacements and modifications in compliance with integrity management rules, best practices, and relocation of facilities to mitigate threats posed by natural forces such as flooding, land movement, and erosion.

4.2.2 Distribution Integrity (DIMP)

Distribution Integrity is outlined in 49 CFR 192 Subpart P- Gas Distribution Pipeline Integrity Management. This federally mandated program requires operators to create a written Integrity Management Program that takes into consideration: system knowledge, threat identification, evaluation and risk ranking, identification, and implementation of measures to address risk, measurement of results, and reporting.

Activities in this category include projects warranting Accelerated Action ("AA") to address a system integrity risk. These AA projects are identified through risk modeling, industry identified threats, and by subject matter experts within the Company, and include:

- Replacement of vintage plastic services,
- Relocation of facilities under structures,
- Replacement of valves and fittings susceptible to leakage,
- Protection of above grade gas facilities,
- Crossbore investigation, and
- Relocation of distribution gas lines to mitigate threats posed by natural forces such as:
  - Flooding
  - Land movement, and
  - Erosion.
- Enhanced EFV Installation – installation of EFVs on services that were installed prior to the EFV rule issued in 2006
- Dithiazine – a sulfur compound found in natural gas that has been known to cause equipment failure especially in district regulators.

4.3 Safety Policy and Practices

NW Natural also implements risk reduction activities not explicitly required by the federal code. These actions have been identified as prudent safety practices intended to enhance public safety, improve system reliability, and maintain the safe operation of NW Natural's above and below-ground facilities including LNG Plants and underground natural gas storage facilities. These risk reduction actions include:

- Seismic vulnerability assessments of LNG Plants, the Mist Underground Storage Facility, and Transmission Pipeline System as recommended by SB 33 (2013) and consistent with the Governor's Resiliency 2025 Plan
- Accelerated replacement of vintage materials
- Transmission inspection outside of high and moderate consequence areas.
- Development of a PSMS
- Proactive EFV installation
- Locate ticket risk modeling
- Natural forces assessments of NW Natural's transmission system as part of NW Natural patrol and surveillance programs.

5. Projected and Preliminary Costs Presented in this Plan

The 2021 Capital and O&M costs presented in this plan are projected based on current expenditures for each of the identified projects through the end of the year. Costs presented for the significant safety initiatives are preliminary for planning purposes and do not include NW Natural overhead costs. Costs for safety projects under consideration will be presented in future SPPs.

6. 2022 Capital Safety Investment

In 2022, NW Natural estimates it will invest $12 MM in capital to comply with DIMP, TIMP, and other regulations. Significant projects in this category include:

6.1 Springfield Transmission (ILI) (2021-22 estimate of $1.2 MM):

This project involves transition of the Springfield transmission line from direct assessment to ILI. The Springfield transmission line is the primary feed to downtown Springfield and large industrial customers in the area. This pipeline is approximately 3 miles and routed along Harlow Road, which is a major thoroughfare between the cities of Eugene and Springfield. Work on this project in 2021 with planned completion in 2022.

6.2 Pro-active EFV Installations (2022 estimate of $600,000):

On October 14, 2016, the U.S. Department of Transportation's ("DOT's") Pipeline and Hazardous Materials Safety Administration ("PHMSA") adopted code requiring the installation of EFVs or shut-off valves on all new or replaced branched service lines (Docket No. PHMSA-2011-009). While the code requires EFV installations be installed in all new or replaced branched service lines, it did not require retrofitting EFVs on existing services.

NW Natural believes a proactive EFV installation program is a prudent action that can mitigate the consequence of a gas release resulting from excavation damage to a gas service line. NW Natural is implementing a policy to retrofit EFVs on existing gas service lines when the buried portion of the service line is exposed and the work involves the interruption of gas service.

This pro-active EFV program was initiated in 2020 and will continue to be a safety program.

6.3 McMinnville/Lafayette ILI (2022 estimate of $2.6MM):

This project involves the transition of the McMinnville/Lafayette transmission line from ECDA to ILI assessment. The McMinnville/Lafayette transmission line is a 6" transmission main that connects to the Central Coast feeder near Amity, OR and runs north 13 miles to serving the residential and industrial customers of McMinnville. The transmission main terminates in the town of Lafayette north of McMinnville. Design work to modify the pipeline will begin in 2021 with construction starting in 2022; cleaning ILI assessment, data analysis, and remediation activities will continue through 2022.

6.4 North Eugene Industrial Trans (2022 estimate of $2.1M)

This project involves the transition of the North Eugene Industrial transmission line from ECDA to ILI assessment. The North Eugene Transmission line is a 5 mile long 6" and 8" transmission line primarily serving the residential and industrial customers located along the Randy Pape Beltline highway. The line terminates at the Northwest Expressway. Design and preliminary construction work coordinated with City of Eugene public works projects will be done in 2021. Cleaning and ILI assessment activities will continue through 2022 with data analysis and remediation/repairs completed in 2022.

6.5 Underground Storage – Well Integrity (2022 estimate of $3.0 MM)

PHMSA has issued an Interim Final Rule incorporating by reference American Petroleum Institute ("API") Recommended Practice 1171 referred to as the Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs by reference. NW Natural developed a Mist UGS Risk Management plan and has begun work on the program. Work in 2022 will involve assessments of the production casings of 6 storage wells. The assessments will include downhole wireline logging of the production casing strings using both multi-arm caliper and magnetic flux tools to identify deformations and metal loss features.

6.6 Other safety projects and programs (2022 estimate of $2 MM):

Pipeline Replacement due to Seismic/Natural Forces

Portions of NW Natural's distribution and transmission system cross through landslide faults, seismic faults, sensitive areas, and waterways. Due to significant weather events or the passage of time, the integrity of these pipelines may become at risk. When identified during patrols, routine maintenance, or other stakeholder the Integrity Team develops plans to remediate these at-risk pipelines as they are identified.

Valve Isolation Plans

NW Natural is working to develop a strategy for identifying and installing additional valves in the distribution system to assist in the isolation of portions of the distribution system in case of an emergency or third party damage.

Meter Protection Installation

NW Natural will continue installation of guard posts adjacent to meter sets that are determined to be at risk of damage due to vehicle or equipment contact.

Pipeline Modification due to ROW Encroachment

Patrols of NW Natural Pipelines may discover structures or other encroachments built over or adjacent to pipelines that can impact the safe operation or access to a pipeline. This program works with landowners to remediate these encroachments.

Pipeline Material Identification (PMI)
At selected transmission pipeline anomaly remediation sites NW Natural has instituted a process using technology to non-destructively test and acquire data regarding pipe material properties. In addition, when the Transmission Integrity rule went in to effect over twenty years ago NW Natural began keeping short (18"-24" long) sections of pipe for future reference. These spools will be destructively tested to obtain pipe material properties that were not required as part of the original installation documentation. The material data obtained through this program will be stored in the permanent record for each pipe segment.

6.7 ASV/RCV Installation (2022 estimate of $700k)

To assist in the timely and efficient closure of valves on the transmission system, NW Natural is continually identifying locations where ASV/RCV valves can reasonably be installed, or existing valves retrofitted in order to facilitate isolation of the transmission system.

6.8 Historical Capital Expenditure - Safety Project Plan (System Integrity)

The Historical Capital Expenditures below are actual expenditures for each of the presented years.

Year	Expenditure
2015	$17,190,356*
2016	$ 7,772,763
2017	$ 5,925,409
2018	$ 9,699,814
2019	$ 10,231,431
2020	$ 8,900,000
2021	$8,200,000

*Final year of known bare steel main replacement

Historical capital expenditures include:

- Work to modify pipelines to accept inline inspection devices; including removal or replacement of non-piggable fittings and facilities required to launch and receive inline inspection devices.
- Pipeline relocation to mitigate threats including outside forces and natural forces. This work does not include relocations due to utility conflicts, or third-party improvement projects.
- Pipe replacements and testing in compliance with federal and state regulations.

- Ongoing DIMP AA programs/projects such as Vintage Plastic, Guardpost installations, Proactive EFV installations, etc.

7. 2022 O&M Expenditures

In 2022 NW Natural expects to spend $3.4 in O&M to address and comply with DIMP, TIMP, damage prevention, and public awareness.

Activities that reflect expenditures in this category include costs for supplies (office/field), reference materials, education (conferences/workshops), vendor and contract costs associated with transmission assessments, sewer crossbore investigations and remediation, public awareness program materials, advertisements and mailings, and natural forces investigation and remediation. Additionally, this category covers the development, initiation, and execution of studies and consulting fees related to integrity requirements, such as class location studies and third-party geotechnical site evaluations to address and mitigate risk.

O&M also includes some non-capital internal labor in support of NW Natural's system integrity program ("SIP"). These costs include the Integrity Management staff (7 FTE), damage prevention specialists (4 FTEs) involved in damage prevention/investigation, and a public information officer for safety outreach, training, and program administration. The Integrity Management group may also utilize other internal resources in support of SIP activities which includes GIS analysts, Customer Service, Construction, and other subject matter experts. Significant O&M projects include:

7.1 Sewer Crossbore Inspections (2022 estimate of $1.6MM):

The sewer crossbore program involves the visual inspection of sanitary sewers for incidences of gas line crossbores. In installations where trenchless technology was used to install polyethylene pipe, there exists the possibility the gas line was bored through a sewer main or lateral. NW Natural's policy is to expose all foreign line crossings when performing trenchless work. Sewer crossbores typically occur when facility owners fail to locate their pipe, creating a situation where NW Natural is unable to expose facilities during construction. This is an industry-wide threat. Although sewer crossbores are not isolated to gas operators, the consequence when gas lines are involved can be high. This program identifies existing trenchless polyethylene installations and inspects the sewers in the vicinity to identify crossbores.

7.2 Transmission Inline and Direct Assessment Reassessment and Remediation (2022 estimate of $1.3MM):

This work includes the federally prescribed seven-year reassessment of transmission pipelines in HCAs and is comprised of both inline inspection and direct assessment of transmission assets and associated repairs.

7.3 Natural Forces (2022 estimate of $300,000):

Where the threat of natural forces can be mitigated without pipe replacement or rerouting, NW Natural may choose to address the threat through site work. This option is necessary in situations where a reroute is not feasible due to environmental restrictions or where a pipeline serves a critical customer or provides a single feed to a distribution system. Work may include armoring of slopes, re-grading of sites, culvert improvements, and retaining structures to address land movement and drainage issues.

7.4 Damage Prevention (2022 estimate of $800,000):

In compliance with DIMP regulations, and to address the single largest threat to gas facilities, NW Natural maintains a damage prevention department. The department consist of a supervisor and 4 FTE damage prevention specialists whose responsibilities include damage prevention through high risk locate ticket intervention, training, attendance at pre-construction meetings, participation in Utility Coordinating Councils, and support of the 811 One-call system. Damage prevention specialists are also responsible for the investigation, enforcement, and contractor training related to excavation and third-party damage.

7.5 Public Awareness (2022 estimate of $1,050,000):

NW Natural's Public Awareness program meets the requirements mandated in API RP 1162, adopted by reference by PHMSA into Part 192.616(a),(b), and (c). This program promotes public safety through communication and outreach focused on educating customers and the public about natural gas safety. The program includes customer correspondence, mailers, advertisements, community events, mobile phone applications, and brochures to excavators, contractors, public officials, residences and businesses along pipeline rights-of-way and in high consequence areas, floating homes, and schools.

The Public Awareness Plan utilizes television and radio advertising, bill inserts, social media, and events to promote natural gas safety awareness. Targeted outreach and public awareness materials are provided annually to customers near transmission pipelines, as well as contractors, excavators, and first responders within NW Natural's service territory.

7.6 Right-of-Way Encroachments (2022 estimate of $100,000):

Pipeline patrols are used to identify changes in site conditions. An example of such a change is the installation of structures over pipelines, and inside dedicated pipeline rights-of-way, or easements. In some instances, the remediation may involve the relocation of structures and other non-gas facilities.

7.7 Historical O&M Expenditure - Safety Project Plan (System Integrity):

The historical O&M expenditures below are actual expenditures for each of the presented years (not including PSMS, damage prevention or public awareness expenditures).

Year	Expenditure
2015	$4,034,218
2016	$4,889,618
2017	$4,771,267
2018	$4,000,000
2019	$3,052,000
2020	$3,100,000
2021	$2,900,000

Historic O&M expenditure included:

- Regulatory transmission assessments including the investigation and remediation of identified anomalies resulting from inline inspection and external corrosion direct assessment (ECDA).
- Sewer crossbore inspection program.
- Investigation and remediation of natural forces including landslides, flooding, erosion, etc.
- Buildover remediation where structures encroach into pipeline right-of-way.
- Digital conversion of historical facility records to facilitate system knowledge.
- Remediation of difficult to operate valves.
- Maintenance of Integrity Risk model as a result of geographical and system changes.

These above costs do not reflect those related to ongoing maintenance of facilities including right-of-way clearing, patrols, leakage, cathodic protection, and other ongoing routine O&M work.

8. 2022 Significant Safety Initiatives

8.1 Changes in TIMP Assessment Methodology

In 2022 NW Natural will extend the use of inline inspection (ILI) for integrity assessment of transmission pipelines assessed at seven-year intervals. Inline inspection tools have the advantage over direct assessment and pressure testing because they assess the entire pipeline maintaining constant contact with the inner wall providing data allowing for the identification of interacting anomalies such as pipe deformation and metal loss. In 2022 NW Natural will change the assessment methodology of the following pipelines.

The McMinnville/Lafayette Transmission line supporting the City of McMinnville and surrounding areas. The 13-mile-long pipeline is routed along Oregon Highway 99W.

The Springfield transmission line is the primary feed to downtown Springfield and large industrial customers in the area. The 3-mile-long pipeline is routed along Harlow Road.

The north Eugene Industrial Transmission line serving industrial, commercial, and residential customers in north Eugene. The 5-mile-long line pipeline is routed along the Randy Pape Beltline Highway.

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8.2 Pro-active EFV Installations

NW Natural has installed EFVs on all new single-family residential services since February of 1999. In 2006, Federal Code was modified to require the installation of EFVs on all new residential and small commercial services. NW Natural will continue and expand the program installing EFVs on existing residential and small commercial services when the buried portion of the service line is exposed and service to the customer is interrupted. NW Natural believes proactive installation of EFVs is a prudent and pragmatic approach that can mitigate the consequence of an excavation damage to a service line.

9. Safety Projects/Programs Being Evaluated at this Time – Tracking and Traceability

NW Natural is developing a roadmap to meet the proposed requirements of the Plastic Pipe Rule (Docket No. PHMSA–2014–0098). The DOT has designated the Plastic Pipe Rule a "significant rulemaking" due to economic impact; compliance with the Plastic Pipe Rule will require new equipment, software, and process changes by NW Natural to meet tracking and traceability requirements.

When the final rule is issued and the impact of the rule on current operations is understood, the Company will develop a program that will be included in future SPPs.

In compliance with recent Regulatory Mandates involving material verification of steel transmission pipelines NW Natural has implemented a non-destructive material verification program to collect material property data on transmission pipeline assets. This program involves material testing of in-service pipelines during planned work to collect material data including metallurgy that was not required at the time of installation.

NW Natural has also developed a program to destructively test segments of pipeline that were removed from past transmission projects to collect the material property information. Collecting material information from the in-service transmission mains and the destructive tests from the historical transmission mains will allow NW Natural to develop a library of material property data.

10. Cost Benefit Analyses & Alternative Analysis

The performance of a cost benefit analysis and alternatives analysis is difficult in the context of safety programs mandated by regulation. As a result, a cost benefit analysis has not been a primary consideration in this report because these safety projects are mandated by CFR, dictated by industry best practices, or driven by operational requirements. The assigned risk and prioritization for implementing these projects are based on in-depth studies and analysis of NW Natural's transmission and distribution systems as well as plant and storage assets. Studies performed as part of normal operations provide measurable and continual feedback needed to perform safety related work for which there are few practicable alternatives.

Alternative analysis and in-depth studies are useful when they identify threats and risks that can be mitigated or eliminated through the application of performance-based best practices, engineering analysis, operational knowledge, and subject matter experts. Where the Code of Federal Regulations prescribe compliance activity or mandate programs, the use of cost benefit, or alternative, analysis is not warranted.

When a pipeline safety initiative requires a cost benefit or alternative analysis NW Natural may select a qualified external resource to perform the analysis.

11. Legislative Update

11.1 Docket No. PHMSA-2011-0023 - the Safety of Gas Transmission and Gathering Lines

11.1.1 Rulemaking No. 1

Regulatory Mandate – involves MAOP reconfirmation, expansion of assessment requirements outside of high consequence areas, material verification, seismicity, reporting requirements, other related items. This rulemaking was published in October of 2019. NW Natural is in compliance with the rule at this time.

11.1.2 Rulemaking No. 2

Non-Regulatory Mandate – involves repair criteria, integrity management improvements, cathodic protection, and management of change, risk modeling requirements, external corrosion, internal corrosion, risk assessment requirements, safety of launchers and receivers, surveillance after weather events, and other related rules. This rulemaking is on currently on hold.

11.1.3 Rulemaking No. 3

Safety of Gas Gathering Pipelines – involves gathering lines. The rule is currently on hold.

NW Natural will assess the full impact of all new or amended rules once published to understand the impact on operations and engineering practices. NW Natural will update programs and existing safety projects as needed to comply with new mandated requirements.

11.2 Docket No. PHMSA-2016-0016 – Underground Storage Facilities for Natural Gas

On February 12, 2020 the Final Rule incorporating API Recommended Practice 1171 referred to as the Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs by reference was published. NW Natural developed a storage well integrity program in compliance with API 1171 incorporating all required provisions into operations at Mist. NW Natural program is in compliance with the final rule as published.

12. Completed Projects (or scheduled to be completed in 2021)

12.1 Eugene Transmission (ILI) ($3.3 MM - Actual):

This project involved the transition of the Eugene transmission line from direct assessment to ILI. The Eugene transmission line is the primary feed to downtown Eugene and the University of Oregon. This pipeline is approximately 4 miles and is routed along Coburg Road. Work on this pipeline was completed in 2021.

12.2 Underground Storage - Well Integrity ($3.5MM – Actual)

This project involved the re-work and baseline assessment of seven wells in the Mist storage field. The 2021 projects are included in year three of NW Natural's well integrity baseline assessment work that includes down hole assessment of production casing and re-work of well tubing as at regular intervals. The program was developed to meet compliance with PHMSA's adoption of APR RP 1171 - Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs. This is a multiyear project planned for completion in 2027.

12.3 South Eugene Transmission (ILI) ($1.4 MM - Actual):

This project involves transition of the South Eugene transmission line from direct assessment to ILI. The South Eugene transmission line is a transmission line from the South Eugene gate that primarily serves the IP Springfield facility and is approximately 6.5 miles in length. Work including station upgrades was completed in 2021. The ILI assessment and remediation of any identified anomalies will be completed in 2021.

12.4 Seismic Vulnerability Assessment and Study of NW Natural's Transmission Line System (2021 estimate of $1MM):

The performance of this assessment and study was completed in compliance with the recommendations of SB 33 (2013) published on October 1, 2014. SB 33 (2013) and in furtherance of the Governor's Resiliency 2025 Plan.

Results of the study will be used to identify projects to replace and/or fortify facilities determined to be vulnerable during events such as a Cascadia subduction zone earthquake. As identified and prioritized, these projects will be included in future SPPs. Future projects will complement existing TIMP mitigation programs, including but not limited to: installation of automatic shut-off valves ("ASVs") or remote control valves ("RCVs"), elimination of bridge crossings, natural forces mitigation work, system reinforcement, and valve installation.

12.5 Underground Storage Integrity – Mist Reliability ($2.2M - Actual):

As part of a mist reliability study and in anticipation of PHMSA's adoption of RP 1171, NW Natural performed inline inspection of four transmission pipelines that transport natural gas between storage wells at Mist into the NW Natural transmission system.

12.6 Labish Shallow Pipe Remediation ($1M - Actual):

As a result of NW Natural's regularly scheduled patrols of the transmission system a 1200' long section of 12" transmission pipe north of Salem was identified as having insufficient ground cover. Due to the depth of the pipe and the farming activities in the area the pipe was replaced. Work was completed in the fall of 2020.

12.7 12" Willamette River Crossing ($1.6M - Actual):

In 2014 an inline inspection was performed on Pipeline S02 from Aurora to Tualatin. This pipeline was primarily 12" in diameter and included a 10" Willamette River Crossing. During the inspection at the river crossing the geometry of the 10" pipe damaged the inspection tool. This project replaced the unpiggagle 10" section with a 12" river crossing allowing the line to be inline inspected. This crossing was installed, and successful ILI assessment completed in 2020.

13. Conclusion

This SPP provides an overview of NW Natural's pipeline safety initiatives and commitment to the safe and reliable delivery of natural gas to the communities we serve. Through its 160-year history, NW Natural has been committed to identifying threats to pipeline safety and taking steps to address and mitigate those threats. Looking forward to the role natural gas will play in our energy future, and as members of the communities we serve, NW Natural recognizes the trust placed on us by our neighbors and customers. NW Natural will continually work to ensure public safety and maintain the integrity of our natural gas system.

NW Natural Pipeline System Safety Capital Projects 2005-2018

1. **Project Name: Navy Heights**
   Year: 2006
   This pipeline safety project's scope of work remediated a natural forces threat and included the replacement of 3,470 feet of 6-inch Class D pipe via horizontal directional drilling (HDD) technology for a pipeline that serves as the single source of natural gas to Astoria. In 2006 a landslide in this area exposed the pipe and caused undo stress on the pipe. Replacement of the pipe facing the landslide hazard via HDD allowed the pipe to be installed at a deeper depth in stable soils.

2. **Project Name: P11 Westside Feeder ILI Conversion**
   Year: 2007
   The P11 Westside Feeder is a 16-inch 400 MAOP, 12.7 mile-long transmission pipeline that serves the west side of Portland, between the Bethany area north of Highway 26 and South Beaverton. In response to the 2003 Transmission Integrity Management rule the Company initiated a program to make all transmission lines capable of inline assessment. This was the first pipeline that NW Natural made capable of inline assessment. This pipeline safety project's scope of work included the removal and replacement of fittings that would not allow passage of inline inspection tools, as well as pipeline cleaning and inspection of the pipeline with inline inspection tools. Post-assessment digs and pipeline repairs were performed to address anomalies identified during the pipeline assessment inspection.

3. **Project Name: P25.02 ILI Conversion**
   Year: 2008
   This was one of the first transmission pipelines that NW Natural made capable of inline assessment. This pipeline safety project's scope of work included the removal and replacement of fittings that would not allow passage of inline inspection tools from multiple locations along the P25.02 pipeline along Columbia Blvd in North Portland, as well as pipeline cleaning and inspection of the pipeline with inline inspection tools. Post-assessment digs and pipeline repairs were performed to address anomalies identified during the pipeline assessment inspection.

4. **Project Name: Young's Bay Pipeline Replacement**

Year: 2008

This pipeline safety project's scope of work remediated a natural forces threat and included the replacement of 4,500 feet of 8-inch Class D transmission pipe via HDD, for a pipeline that is the single source of natural gas from Warrenton to Seaside and Cannon Beach. The original 1966 8-inch pipeline was dredged in place along the bottom of Young's Bay. The pipeline was replaced due to the discovery that the original pipeline had become exposed due to tidal erosion in the bottom of the bay. The 8-inch pipeline exposure was discovered during annual maintenance inspections where Company contract divers inspect legacy dredged river and water body crossings.

5. **Project Name: Salmon River / Highway 18 Pipeline Replacement, Central Coast Feeder**
   Year: 2008

   This pipeline safety project's scope of work remediated a natural forces threat and included the replacement of 5,200 feet of 12-inch Class E transmission main that crossed the Salmon River in three locations, with a new pipeline that reduced the number of Salmon River crossings to one location in the Van Duzer Corridor, east of Rose Lodge. The original 1965 pipeline was installed via open trench across the Salmon River and was found to be exposed due to riverbed erosion. The new pipeline was installed at a deeper depth below the Salmon River riverbed and State Highway 18 via HDD technology.

6. **Project Name: Sullivan's Gulch Bare Main Replacement Project**
   Year: 2010
   This pipeline safety project's scope of work remediated a vintage material threat and included the replacement of 4,400 feet of 8-inch bare steel main with 8-inch coated steel pipeline. The project eliminated a significant segment of bare main in the Portland metro area, including a bare main crossing over Interstate 84 near SE 12th Avenue.

7. **Project Name: Calapooia River**
   Year: 2010

   This pipeline safety project's scope of work remediated a natural forces threat and included the replacement of 900 feet of 10-inch Class D transmission main across the Calapooia River near Albany. The original pipeline was installed in 1960 by dredging a trench across the Calapooia River, and supplied gas to the Corvallis and Philomath communities. During an underwater pipeline inspection the pipeline was found to be

exposed due to riverbed erosion. The new pipeline was installed at depth below the riverbed via HDD.

8. **Project Name: Rock Creek Replacement, Central Coast Feeder**
   Year: 2010

   This pipeline safety project's scope of work remediated a natural forces threat and included the replacement of 3,000 feet of 12-inch Class E transmission main along the Central Coast Feeder, which is the primary source of gas for Lincoln City, Toledo and Newport. The original pipeline crossing had become exposed due to riverbed erosion. The new pipeline was installed at depth below the riverbed via HDD technology.

9. **Project Name: SW Vermont Street Bare Steel Replacement**
   Year: 2011

   This pipeline safety project's scope of work remediated a vintage material threat and included the replacement of 1,850 feet of 6-inch bare steel main in SW Portland.

10. **Project Name: Windsor Island River Crossing Pipeline Replacement**
    Year: 2012

    This pipeline safety project's scope of work remediated a natural forces threat and included the replacement of 1,500 feet of 10-inch Class E transmission pipeline across the Willamette River north of Keizer. The original pipeline was installed in 1964 by dredging a trench across the Willamette River and had become exposed due to riverbed erosion. The new pipeline was installed at depth below the riverbed via HDD.

11. **Project Name: South Yamhill River Crossing Pipeline Replacement, McMinnville**
    Year: 2012

    This pipeline safety pipeline safety project's scope of work remediated a natural forces threat and included the replacement of 1,740 feet of 6-inch Class D transmission pipeline across the South Yamhill River south of McMinnville. The original pipeline was installed in 1964 by dredging a trench across the river and had become exposed due to riverbed erosion. The new pipeline was installed at depth below the riverbed via HDD.

12. **Project Name: South of Monmouth Bare Steel Replacement**
    Year: 2013

    This pipeline safety project's scope of work remediated a vintage material threat and included the replacement of 12 miles of 6-inch bare steel main south of Monmouth and

Independence. The purpose of the project was to eliminate the 6-inch bare steel main installed in 1931.

13. Project Name: P30 South Yamhill River Crossing Fort Hill, Central Coast Feeder
Year: 2014

This pipeline safety project's scope of work remediated a natural forces threat and included the replacement of 915 feet of 12-inch Class E transmission main across the South Yamhill River east of Grand Ronde. The original 1965 pipeline was installed via open trench across the South Yamhill River. The pipeline was found to be exposed due to riverbed erosion. The new pipeline was installed at a deeper depth below the riverbed via HDD technology.

14. Project Name: Ellendale Avenue Bare Steel Replacement
Year: 2015

This pipeline safety project's scope of work remediated a vintage material threat and included the replacement of 8,900 feet of 6-inch bare steel main along Ellendale Avenue east of Dallas. The purpose of the project was to eliminate the 6-inch bare steel main. 2015 was the last year of the Company's bare steel main replacement safety project program.

15. Project Name: Nevada Street Bare Steel Replacement
Year: 2015

This pipeline safety project's scope of work remediated a vintage material threat and included the replacement of 500 feet of 6-inch bare steel main along the Nevada Street right-of-way crossing of Interstate 5 near the Terwilliger Curves in Portland. The purpose of the project was to eliminate the 6-inch bare steel main. 2015 was the last year of the Company's bare steel main replacement safety project program.

16. Project Name: SW Gaarde Road and Highway 99W Transmission Pipeline Replacement
Year: 2015

This pipeline safety project's scope of work included the replacement of 1,430 feet of 10-inch transmission main in Tigard due to shallow depth of cover in advance of an ODOT roadway project.

17. Project Name: SE Transmission Rehydro
Year: 2015

This pipeline safety project's scope of work included the hydrotesting of approximately 8 miles of the P20 10-inch transmission main installed in 1956 between SE Gate in Clackamas and Bell Rd. Station in SE Portland. The purpose of the project was to accomplish a successful hydrostatic pressure test due to missing hydrotest records from the pipeline's original construction in 1956.

18. Project Name: North Coast ILI Conversion
Year: 2018

This pipeline safety project's scope of work included the removal and replacement of non-piggable fittings along approximately 49 miles of 16-inch and 10-inch North Coast Feeder transmission mains between the Deer Island Gate Station and the Wicks Road Regional Station east of Astoria and Warrenton. Removal of the non-piggable fittings allowed the Company to perform its first inline inspection of these transmission pipelines originally installed in 1965. Post-assessment digs and pipeline repairs were performed to address anomalies identified during the pipeline assessment inspection.

19. Project Name: Central Coast Feeder ILI Conversion
Years: 2018 and 2019

This pipeline safety project's scope of work included the removal and replacement of non-piggable fittings along approximately 91 miles of 10-inch and 12-inch Central Coast Feeder transmission mains between the McMinnville-Amity Gate northeast of Salem and the Toledo Regional Station. Removal of the non-piggable fittings allowed the Company to perform its first inline inspection of these transmission pipelines originally installed in 1964 and 1965. Post-assessment digs and pipeline repairs were performed to address anomalies identified during the transmission pipeline assessment inspection.

20. Project Name: South Santiam River Pipe Replacement
Year: 2018

This pipeline safety project's scope of work remediated a natural forces threat and included the replacement of 1,200 feet of 4-inch high pressure distribution main crossing the South Santiam River north of Lebanon. The pipeline was found to be exposed due to riverbed erosion. The new pipeline was installed at a deeper depth below the riverbed via HDD technology.

NW Natural®

Rates & Regulatory Affairs

ADV 1789

NW NATURAL ADVICE NO. 25-23 SCHEDULE 160 TSA COOS COUNTY

Data Request Response

Request No.: ADV 1789 CUB IR 1

Please provide the load of each class of customer that NWN provides service to in Coos Bay, including transport customers, in therms/month and BTUs/month.

Response:

Refer to ADV 1789 CUB IR 1 Attachment 1 for Coos County customer volumes (in therms and BTUs), by Rate Schedule and Rate Class, by Month, for January 2014 through September 2025.

| [redacted] | [redacted] | [redacted] |

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Rates & Regulatory Affairs

ADV 1789

NW NATURAL ADVICE NO. 25-23 SCHEDULE 160 TSA COOS COUNTY

Data Request Response

Request No.: ADV 1789 CUB IR 6

Please provide the estimated useful life remaining on the existing Coos County pipeline in years.

Response:

The existing Coos County pipeline was placed into service in 2005 and the classification of pipeline assets would be FERC Account 367 – Mains. The current OR approved depreciable life of FERC 367 is 50 years (100/accrual rate of 1.99). The purchase price of $1 would be placed into service in FERC account 367.

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ADV 1789

NW NATURAL ADVICE NO. 25-23 SCHEDULE 160 TSA COOS COUNTY

Data Request Response

Request No.: ADV 1789 CUB IR 17

Is it correct that there will be no work on the pipeline until rate recovery is resolved? If this is incorrect please explain the work that will be done and under what circumstances. Please itemize the expected costs from that work.

Response:

The Company assumes that the work asked about refers to the three landslide mitigation projects discussed in ADV 1789, as well as the general operations and maintenance of the Coos County pipeline that the Company previously performed on behalf of Coos County.

The Company will not perform any of the landslide risk prevention work identified in ADV 1789 until the Company receives regulatory certainty regarding its decision to purchase the Coos County Pipeline for the nominal sum of one dollar. To be clear, NW Natural is not seeking pre-approval of any costs to operate and maintain the pipeline or the investments it will need to make upon transfer of ownership. Rather, NW Natural is seeking to ensure that it will not be held to a heightened cost recovery standard simply because it decided to acquire the Coos County Pipeline and pursue a more conventional regulatory framework for the operation of the pipeline. If NW Natural were to maintain the status quo and not assume ownership of the Coos County Pipeline, landslide risks would not be addressed, potentially leading to unplanned service interruptions that could put Oregonians' lives at risk, and that would be costly for NW Natural's industrial and commercial customers. Therefore, cost recovery should be subject to the same standard as any other cost that the Company incurs to maintain its system.

As noted in the third paragraph of page 6 of NWN OPUC Advice 25-23 (ADV 1789), the Company has filed a deferral application to allow it to track O&M costs and would defer recovery of these costs until a future rate proceeding.

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ADV 1789

NW NATURAL ADVICE NO. 25-23 SCHEDULE 160 TSA COOS COUNTY

Data Request Response

Request No.: ADV 1789 OPUC IR 12

Please clarify if the landslide mitigation work referred to in this filing represents a complete solution to the issue. Or does the Company think additional landslide mitigation, or any other extraordinary O&M expense, will be necessary in future years?

Response:

For the landslide mitigation work referred to in this filling listed below are the specific solutions that the Company has determined will address each landslide event:

Mile 98: The Company's geotechnical engineering consultant has recommended relocation of the 12-inch transmission main to a deeper depth, below the identified slide plane elevation. The intention is that the MP 98 Transmission Pipeline Relocation Project will address the current threat to the existing 12-inch transmission main at mile post 98 and no further mitigation work will be necessary.

Coquille River: The Company's geotechnical engineering consultant has recommended relocation of the 4-inch transmission main away from the Coquille River riverbank area to an upland area closer to the state highway. The intention is that the Coquille River Transmission Pipeline Relocation Project will resolve the current threat to the existing 4-inch transmission main along the Coquille River and no further mitigation work will be necessary.

Lookingglass: The Company has received approval from Coos County to hire a geotechnical engineering consultant to evaluate the soil and groundwater conditions at the Lookingglass Slide location and to provide the Company with a recommendation solution to address groundwater movement along the pipeline and restoration of soils. The intent is that this restoration effort will fully address the Lookingglass Slide area but the Company does not know if further O&M expenses will be necessary in the future at this location to augment or make adjustments to the employed solution.

Remaining High Risk Sites: The Company's geotechnical engineering consultant has recommended that the Company continue to frequently monitor these remaining high-risk sites. The Company will follow the recommendation of the Company's geotechnical consultant which states that high risk sites require Frequent Monitoring. Frequent Monitoring is defined as once a month between October and April along with specific criteria for additional monitoring due to weather conditions. Landslide mitigation could necessitate pipeline relocation to address any of these high-risk sites.

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Rates & Regulatory Affairs
UG 527
NW Natural Alternative Rate Mechanism
Data Request Response

Request No.: UG 527 CUB DR 1

Please provide all DR responses, including confidential responses, from ADV 1789.

Response:

NW Natural grants CUB permission to use the responses to DRs in docket ADV 1789, subject to the General Protective Order governing this proceeding.

NW Natural

Rates & Regulatory Affairs
UG 527
NW Natural Alternative Rate Mechanism
Data Request Response

Request No.: UG 527 CUB DR 12

Has Coos County applied for any outside funding to support landslide remediation work? Please list all funding sources applied for and whether or not it was awarded.

Response:

Yes, the County has applied for outside funding to support landslide remediation work from multiple sources.

Coos County applied for and was granted American Rescue Plan Act (ARPA) funds as owner of the pipeline. The County has allocated $1.45 million in these ARPA funds to be spent on the Coquille River project to mitigate the risk of a riverbank washout.

Coos County has also attempted to obtain a FEMA Building Resilient Infrastructure and Communities (BRIC) grant, but funding for this program was cancelled by the federal government in 2025, and its status is currently under judicial review. The County further attempted to obtain a grant through the United States Department of Transportation but were informed that grant eligibility is limited to distribution lines, not transmission lines such as the Coos County Pipeline. Finally, the County has requested a Congressionally Directed Spending (CDS) grant to fund landslide mitigation on the Coquille River. The County is currently waiting for a response to this request.

Additionally, Coos County has federal disaster assistance funds made available after the Federal Emergency Management Agency (FEMA) declared a presidential disaster on July 22, 2025, related to storms in March 2025. The County has inquired with FEMA regarding the eligibility of these funds for landslide-related damage remediation to the Lookingglass portion of the pipeline. FEMA informed the County that grant funds from the disaster declaration cannot be used to relocate the Coos County Pipeline away from the slide area. The County is continuing to evaluate whether any of these funds are eligible for restoration work at the Lookingglass damage site.

Finally, note that Coos County has a pipeline fund that remains available to fund landslide mitigation work. Per a letter Coos County sent to the Commission dated January 9, 2026, the proceeds in this fund at that time were over $600 thousand.

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Rates & Regulatory Affairs
UG 527
NW Natural Alternative Rate Mechanism
Data Request Response

Request No.: UG 527 CUB DR 26

For each area of the Coos Pipeline that requires replacement (e.g. Mile 98, Coquille River, and all additional areas marked as high risk and needing replacements), what is the estimated useful life of each of these replacements?

Response:

FERC account 376 has a 67 year group survivor curve based on the Company's last depreciation study settlement in UM 2363.

The Coos County Pipeline replacement projects will be constructed with API 5L grade X52 high-strength carbon coated steel pipe that is cathodically protected.

The steel pipeline industry predicts a useful service life of 80-100 years for properly maintained cathodically protected buried steel pipelines.

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ADV 1789

NW NATURAL ADVICE NO. 25-23 SCHEDULE 160 TSA COOS COUNTY

Data Request Response

Request No.: ADV 1789 OPUC IR 16

Regarding the Second Stipulation Relating to the Coos County Distribution System in docket UG 152 (Order No. 03-236):

a. What was the modeled gas volume on which the TSA agreement rate was based?
b. What was the actual average gas volume?
c. Please explain why the forecasted gas volumes on the pipeline were not realized.

Response:

a. NW Natural projected a load for residential and commercial customers of 1,326,316 therms in year 1, growing to 7,935,975 therms in year twenty (with year twenty being 2025). Please see UG 152 Exhibit Staff-NWN-CUB-NWIGU-Coos County/1515, Tatom-Henderson-Jenks-Schoenbeck-Whitty for further detail.

b. The average actual total throughput for Coos County customers for the three years 2022 through 2024 was roughly 5.9 million therms annually (including sales and transportation customers).

c. Economic growth in the region, especially in the forest products sector, has not materialized as originally expected since the pipeline entered service.[1]

[1] Refer to the following, for instance, for a discussion of the economic challenges that have faced Coos Bay and Coos County: https://www.opb.org/article/2024/10/25/coos-bay-economy-shipping-timber-federal-funding/.

Senate Bill 32 Work Group

Study of Natural Gas Expansion to Unserved Areas

Report to the Legislative Assembly
Public Utility Commission of Oregon
September 15, 2016

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Executive Summary

Despite strong growth of natural gas customers in Oregon, many Oregonians still lack access to natural gas service. Every city with a population of more than 10,000 has natural gas service, but many communities remain unserved due to the cost to extend natural gas pipelines and distribution systems. These unserved areas generally have populations of less than 1,000 or are located more than 15 miles from a natural gas pipeline.

The Public Utility Commission of Oregon (PUC) allows natural gas utilities to recover investments to extend their distribution systems that are commensurate with the projected revenue from the new customers. These amounts, however, are generally not sufficient to cover the cost of expansion when the facilities needed are considerable and the pool of potential customers in the proposed expansion area is small.

At the direction of the 2015 Oregon Legislature, the PUC formed a Senate Bill 32 Work Group to explore potential mechanisms to increase funding for the expansion of natural gas service. The SB 32 Work Group examined mechanisms both within the PUC's current statutory authority as well as legislative proposals to tap other funding sources.

The SB 32 Work Group made the following findings:

Finding 1: The cost of natural gas expansion into unserved areas is a major obstacle to expansion.

Finding 2: Because the determination of whether expansion will benefit existing customers is based on the comparison of costs to benefits of the expansion, proper accounting for all appropriate benefits is essential.

Finding 3: New customers located within a previously unserved area will receive benefits from expansion (access to new service) and should be charged accordingly.

Finding 4: There are multiple potential funding sources to fill the economic gap for natural gas service expansion.

Finding 5: Multiple funding sources should be bundled when possible. Best practices for bundling multiple revenue sources should be studied and implemented.

Finding 6: If the legislature chooses to create funding sources for the expansion of natural gas service to realize economic, societal, or environmental benefits, it should create transparent subsidies.

The SB 32 Work Group concluded that the distribution extension policies of natural gas utilities could be modified to increase the amount of ratepayer funds to support natural gas service expansion. The SB 32 Work Group concluded, however, that any additional ratepayer revenues resulting from these modifications would not likely be sufficient to fully fund expansion to any city in Oregon that currently does not have natural gas service.

The SB 32 Work Group also identified potential legislative actions that could provide additional revenue to support natural gas expansion. These actions include using general funds or redirecting monies used for local air quality improvement to fill the funding gap for the cost of natural gas expansion. The diverse members of the SB 32 Work Group, however, could not agree on any specific legislative proposals to create these additional revenues.

Introduction

The 2015 Legislature passed SB 32 to address the expansion of natural gas service in Oregon. The bill directed the PUC to form a work group to study ways to expand natural gas service to unserved areas, and to report the work group's findings and conclusions, as well as any recommendations for legislation, by September 15, 2016.

Following meetings with a broad range of stakeholders, the PUC created a SB 32 Work Group comprised of Senator Doug Whitsett, Representative Bill Kennemer, and representatives from utilities, ratepayers, propane dealers, and local governments. The SB 32 Work Group met on four occasions and, as directed by the legislature, evaluated the following issues in its study of natural gas service expansion:

(a) The PUC's policies regarding the extension of natural gas mains;

(b) Mechanisms for funding the expansion of natural gas services, including the use of tariffs, the imposition of charges and fees, the use of unclaimed refunds and the establishment of accounts dedicated to the expansion of natural gas services;

(c) Recommendations by Oregon's natural gas utilities for reforms to expand natural gas service;

(d) Possible processes for including in a utility's rates the cost of projects involving the extension of natural gas pipelines and other infrastructure necessary for providing natural gas;

(e) Possible selection criteria for projects involving the extension of natural gas pipelines and other infrastructure necessary for providing natural gas; and

(f) The potential rate cap for projects involving the extension of natural gas pipelines and other infrastructure necessary for providing natural gas.

This report documents the efforts of the SB 32 Work Group. For context, the report begins with background information on the availability of natural gas service in Oregon, the policies used by the PUC to address extension of service, and the application of those policies to three case studies.

The report then provides the SB 32 Work Group's findings and conclusions on methods by which a natural gas utility may expand its distribution facilities to unserved communities. These findings and conclusions are solely those of the SB 32 Work Group. The SB 32 Work Group did not agree on recommendations regarding legislative action, so no recommendations are included. However, this report does present the legislative proposals that were considered.

Natural Gas Service in Oregon

Three natural gas utilities – Northwest Natural Gas, dba NW Natural; Cascade Natural Gas; and Avista Corporation, dba Avista Utilities – supply gas to more than 800,000 Oregon households and businesses. Currently, NW Natural serves 640,171 Oregonians, including 579,129 households; Avista serves 99,065 Oregonians, including 87,328 households; and Cascade serves 70,083 Oregonians, including 60,114 households.

Over the past 20 years, the number of Oregon customers served by natural gas utilities has doubled. Figure 1 shows the growth from 1975 to 2013 in the number of Oregon homes and businesses that use natural gas.

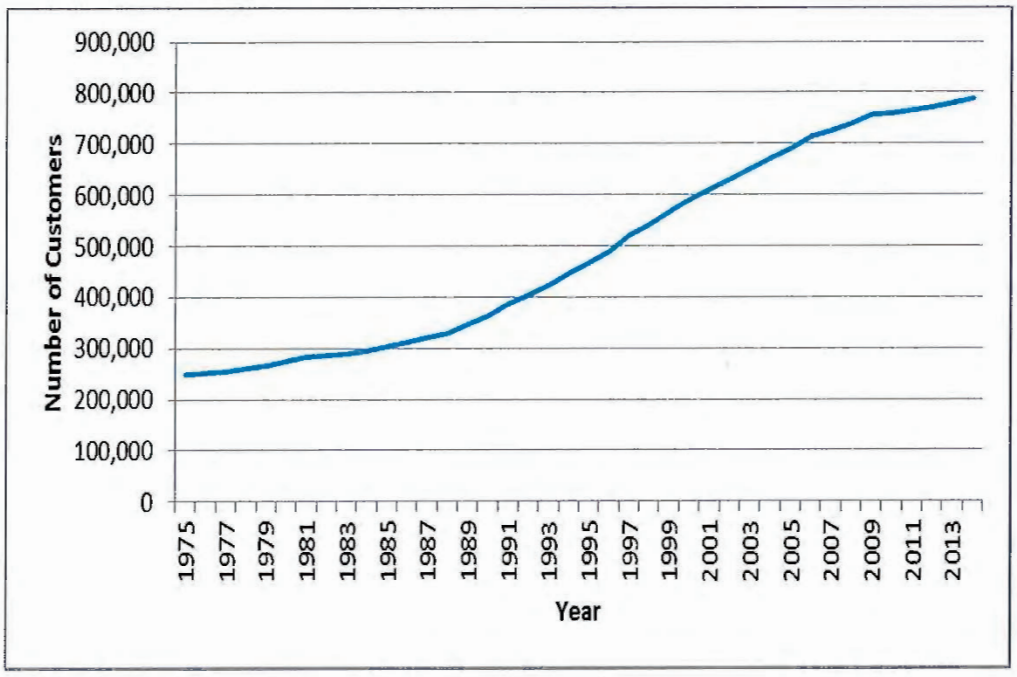


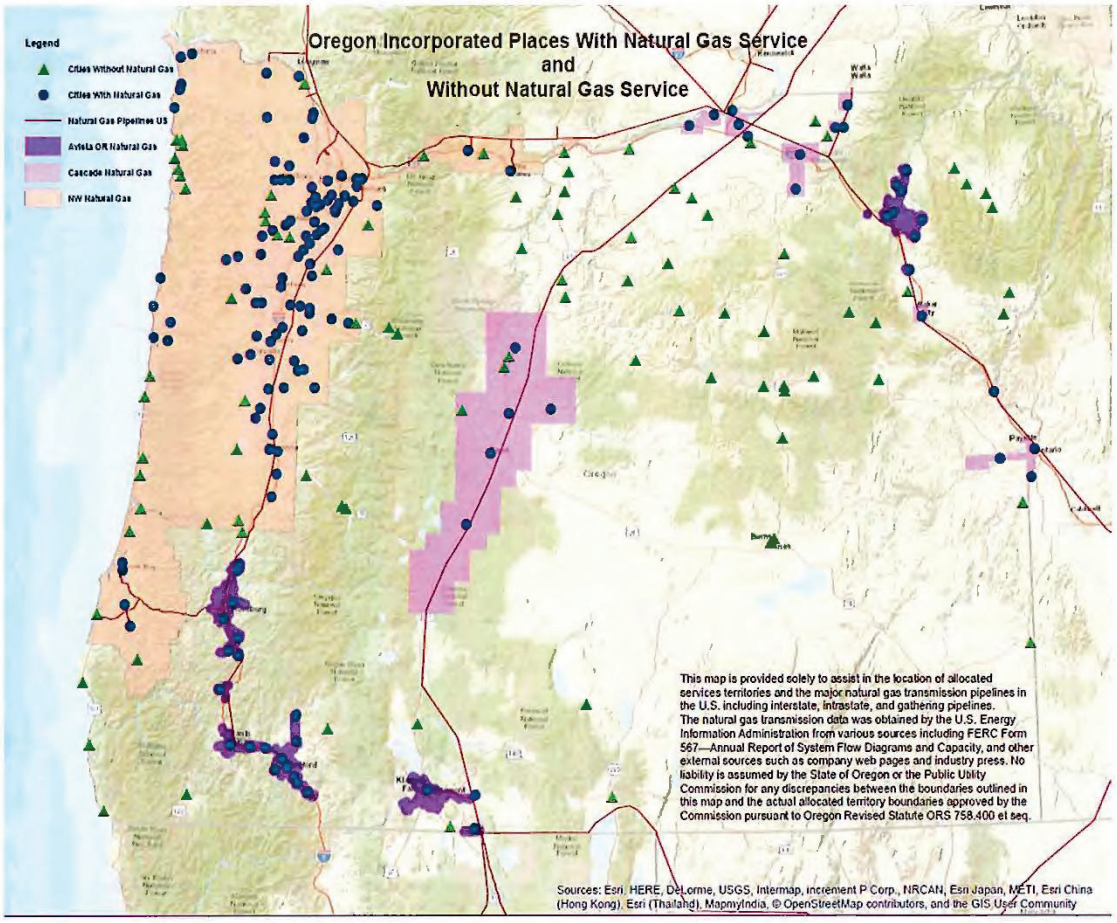
Figure 1: Natural Gas Customers in Oregon

The increase in natural gas customers stems from four primary causes: (1) new construction; (2) conversion from oil and other energy sources; (3) extensions to new

customers in a utility's existing service territory; and (4) new extensions into previously unserved areas.

Over time, Oregon's natural gas utilities have systematically expanded their service areas in more densely populated areas and in areas near natural gas pipelines. Today, a majority of the residents of Oregon's incorporated areas have access to natural gas.

The map below shows the natural gas service status of Oregon's incorporated cities.



Map 1: Oregon Incorporated Cities with and without Natural Gas Service

Two key factors affect an area's access to natural gas service. The first is population size. Figure 2 shows that larger communities have greater access to natural gas service than smaller ones.

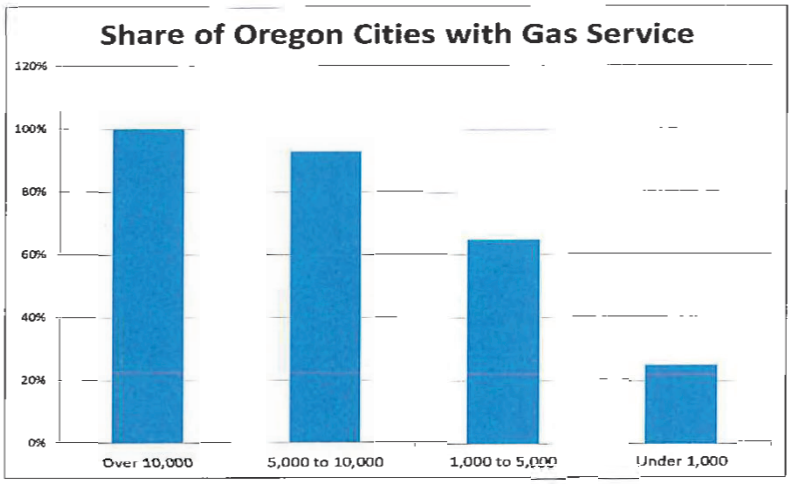


Figure 2: Share of Oregon Cities with Natural Gas

Every city with a population greater than 10,000 has natural gas service. All but two with populations between 5,000 and 10,000 (Florence and Brookings) have service. Most cities with populations between 1,000 and 5,000 have service. In contrast, most cities with populations under 1,000 have no natural gas service.

The second key factor affecting availability of natural gas service is the city's proximity to a natural gas pipeline. Natural gas is transported through a network of intrastate and interstate pipelines, which are subject to regulation by both the PUC and the Federal Energy Regulatory Commission (FERC). Oregon's natural gas utilities receive their gas supply from these pipelines, and build their own pipelines and distribution systems to deliver the gas to customers.

The longer the distance between a city and a natural gas pipeline, the more costly it is for a natural gas utility to serve that area. For this reason, many remote communities remain unserved. Almost all unserved cities with populations over 1,000 are located more than 10 miles from an existing natural gas pipeline. These cities include Bay City, Brookings, Burns, Carlton, Cave Junction, Culver, Dayton, Dunes City, Enterprise,

Estacada, Florence, Gold Beach, Heppner, Hines, John Day, Joseph, Lakeside, Lowell, Oakridge, Port Orford, Reedsport, Rockaway Beach, Sisters, Tillamook, Waldport, Yamhill, and Veneta.

The impact of pipeline proximity is even more dramatic on smaller communities. No city with a population of less than 1,000 that is located more than 15 miles from a natural gas pipeline has natural gas service. Figure 3 shows that all cities with populations under 1,000 that have access to natural gas are near interstate pipelines.

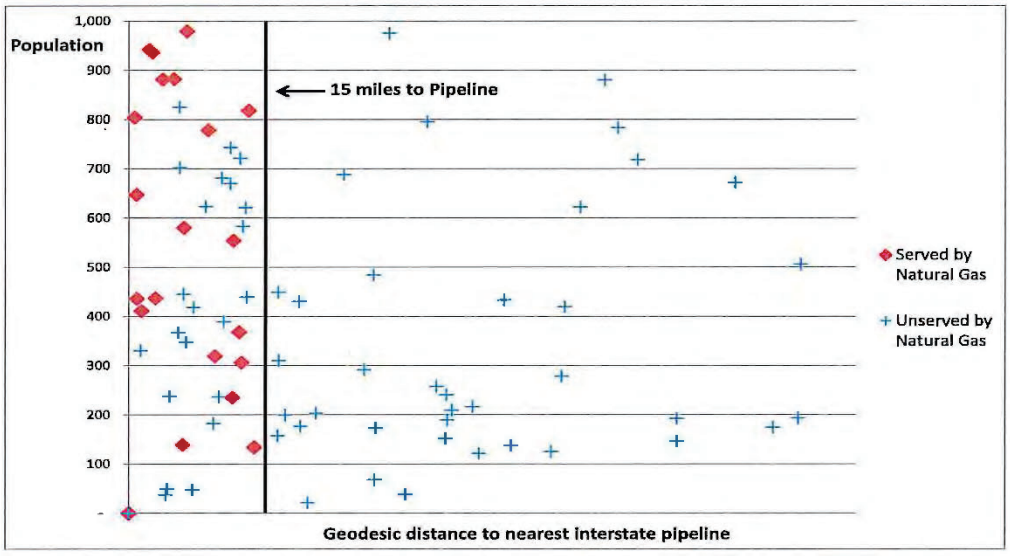


Figure 3: Cities with Population Under 1000 with Natural Gas Service

Extension Policies and Case Studies

The natural gas utilities decide whether to build pipelines and extend their distribution systems into unserved areas, subject to the PUC's review. The utilities also establish their own distribution extension policies, which the PUC reviews and approves to help ensure that the rates paid by all ratepayers for these extensions are fair, just, and reasonable.

The PUC does not require new customers to pay all the costs associated with an extension. Rather, extension policies allow the utility to recover a portion of the extension costs from all customers (usually referred to as a construction allowance), to recognize the increased revenue the new customer will provide through the rates they will pay in the future. Any costs above the construction allowance must be paid by new customers through a surcharge or through other funds secured by the utility or others to fund the expansion.

Each utility currently calculates this allowance for new residential customers differently. NW Natural's construction allowance is five times the annual average margin expected from new customers. Avista's allowance is three times the estimated gross revenue expected from the new customers. Cascade's allowance is 4.5 times the estimated gross margin (gross revenue less cost of gas) to be derived from the new customer.

At any time, a natural gas utility may file a tariff to change its construction allowance formula. The utility must justify the change and show that the formula results in fair and reasonable rates for all ratepayers.

Recent proposals for natural gas expansions into unserved areas provide insight into the conditions for successful expansions. They generally involve a combination of broader taxpayer funding of uneconomic expansion costs, combined with some level of utility ratepayer support. Three expansion projects are discussed below.

Coos County

NW Natural's expansion of service to Coos Bay, North Bend, Myrtle Point, and Coquille is the most notable natural gas service expansion in Oregon over the past 20 years. The expansion project consisted of (1) the building of a 60 mile pipeline from the Roseburg area, and (2) the development of a natural gas distribution system throughout Coos County.

In this case the pipeline was built with the help of state and county bond funds. The 1999 Oregon Legislature approved $20 million in lottery bond funding for construction of the pipeline. Coos County voters authorized general obligation bonds up to $27 million to finance costs of construction not covered by the lottery bond funding.

NW Natural's extension policy, filed and approved by the PUC, addressed the expansion of the distribution system (main and line extensions). The utility was authorized to recover $10 million in distribution-level project costs through existing customer rates. NW Natural was also authorized to recover another $2 million by charging the new customers in Coos County an additional 2 cents per therm for 20 years. After 20 years, this surcharge could be extended if the $2 million was not fully recouped. The company also used $400,000 in shareholder funds to help pay for the new distribution system.

The project went forward and service to Coos County began in January 2005.

Estacada

In 2005, NW Natural examined extending service to Estacada, a city with a population of about 3,000 near Portland.

NW Natural estimated that the extension would cost about $7.5 million, but that only $750,000, or just 10 percent of project costs, could be recovered from ratepayers. Because of a funding gap, NW Natural did not pursue the project.

Lakeview

In 2015, Avista examined extending service into Lakeview, a city with a population of about 2,300 in south-central Oregon.

Avista estimated that the extension would cost about $9 million, but that only $1 million, or less than 15 percent of the total project costs, could be recovered from ratepayers. Because of the need for large amounts of external funding to cover project costs, Avista did not pursue the project.

SB 32 Work Group

Work Group Formation

In September 2015, the PUC solicited stakeholder interest in participating on the SB 32 Work Group. PUC Staff met with representatives from utilities, natural gas pipelines, ratepayers, propane dealers, and local governments to help identify individuals to serve on the work group.

In January 2016, the PUC appointed 11 members to the SB 32 Work Group. Both Senator Doug Whitsett and Representative Bill Kennemer generously agreed to participate. A complete list of the SB 32 Work Group members is set forth below:

SB 32 Work Group Members		
Member Name	**Company/ Organization**	**Representing**
Senator Doug Whitsett	Oregon State Senate	
Representative Bill Kennemer	Oregon House of Representatives	
Clackamas County Commissioner Martha Schrader	Clackamas County	
Lake County Commissioner Ken Kestner	Lake County	
City Administrator Ric Ingham	City of Veneta	
Danelle Romain	Oregon PUD Association	Consumer-Owned Utilities
Joe Westby	Ferrellgas/Blue Rhino	Propane Companies
Dan Kirschner	Northwest Gas Association	Natural Gas Companies (LDC)
Etta Lockey	Pacific Power	Electric Companies
Bob Jenks	Citizens' Utility Board	Residential Customers
Ed Finklea	Northwest Industrial Gas Users (NWIGU)	Industrial Customers

Work Group Activity

Meetings

The SB 32 Work Group met on four occasions in January, March, May, and June 2016. All meetings were open to the public, and other stakeholders were allowed to offer input. Copies of the formal presentations given at the meetings are included in the appendices to this report.

At the January meeting, the SB 32 Work Group heard presentations on energy facility siting, PUC extension authority and policies, and the distribution extension policies and activities of Avista, Cascade, and NW Natural.

At the March meeting, the SB 32 Work Group heard presentations on the Coos County expansion, the proposed Lakeview expansion project, the Oregon propane industry, and natural gas expansion developments in other states.

At the May meeting, the PUC staff facilitated a discussion among the SB 32 Work Group members to address the following questions:

1. Who should invest in natural gas infrastructure in unserved areas in Oregon, and what sources of revenue exist outside of utility ratepayers?
2. What criteria should be used to determine the viability of expansion?
3. Should existing ratepayers help fund expansion of natural gas to new communities? If so, how should the subsidy rate for economic development be determined?
4. How can analytical approaches be improved to increase the forecast adoption rate?
    a. Should we study electric avoided costs due to natural gas conversions?
    b. Should projects advance without anchor customers?

5. Should recovery for expansions be allowed outside of a rate case? If yes:
    a. How should the application process for proposing expansions work?
    b. Should there be a rate cap? If yes, how should the rate cap be applied?
    c. Should there be a surcharge for ratepayers in newly expanded areas? If yes, how should the surcharge be applied (i.e. per therm surcharge, flat monthly surcharge, etc.)?

In addition to this discussion, the natural gas utilities also presented recommendations for actions to enhance the expansion of natural gas into unserved areas. The natural gas utilities' proposals, as well as the propane industry's written response, are attached as Appendices A and B, respectively.

At the final June meeting, the SB 32 Work Group discussed the findings, conclusions, and recommendations it would present to the PUC and to the legislature.

Drafts and Comments

The SB 32 Work Group circulated two drafts for comments. First, it circulated its draft "Findings and Conclusions" among its members for purposes of discussion during its last meeting. Portland General Electric Company (PGE) and the Northwest Gas Association (NWGA) filed comments in response to this first draft.

Second, following its final meeting, the SB 32 Work Group circulated a draft report titled "Study of Natural Gas Expansion to Unserved Areas." Comments were received from NWGA, Senator Whitsett, Lake County Commissioner Kestner, NWIGU, Consumer-Owned Utilities, and the Pacific Propane Gas Association.

All comments are attached in Appendix F.

SB 32 Work Group Findings

The SB 32 Work Group had a robust discussion on a variety of topics. At a very high level, there was general agreement on the following findings:

Finding 1: The cost of natural gas expansion into unserved areas is a major obstacle to expansion.

Case studies of recent and planned natural gas expansion efforts show that the large amounts of additional funding is necessary to cover the costs of gas service extensions into unserved areas.

Finding 2: Because the determination of whether expansion will benefit existing customers is based on the comparison of costs to benefits of the expansion, proper accounting for all appropriate benefits is essential.

Construction allowances may not reflect the full amount of benefits that an expansion of service to unserved areas may provide existing customers. Distribution expansions may be evaluated over too short a time period and other benefits may not be captured in construction allowance formulas.

Finding 3: New customers located within a previously unserved area will receive benefits from expansion (access to new service) and should be charged accordingly.

New customers in a recently-expanded service territory should pay for project costs commensurate with the direct and long-term benefits they receive from getting access to natural gas service. New customer surcharges should be considered a legitimate source of funds for service extension projects.

Finding 4: There are multiple potential funding sources to fill the economic gap for natural gas service expansion.

There are many potential funding sources other than revenue from ratepayers to support the expansion of natural gas service. Obtaining funds from these sources, however, requires action from outside the PUC. Moreover, not all SB 32 Work Group members agree that all the funding sources set out below should be used to fund expansion of natural gas service.

- Economic development grants[1]
- Local taxes and bonds
- Utility shareholder funds
- Lottery revenue
- Community in-kind contributions
- Oregon Health Authority funds related to environmental quality
- Local and county funds to comply with federal and state air-shed standards
- Partial funding by industrial customers or pipelines
- State General Fund

Finding 5: Multiple funding sources should be bundled when possible. Best practices for bundling multiple revenue sources should be studied and implemented.

Because new, large pipeline and distribution extension projects will likely require a significant amount of additional funding to cover project costs, it is important to promote ways to identify and coordinate funding for proposed projects. Any effort to facilitate the expansion of natural gas service should capitalize on the work of existing entities that coordinate economic development in communities.

[1] One example are grants for rural development offered by the United States Department of Agriculture: http://www.rd.usda.gov/programs-services

Finding 6: If the legislature chooses to create funding sources for the expansion of natural gas service to realize economic, societal, or environmental benefits, it should create transparent subsidies.

Although there is no consensus that statutory subsidies should be used for the expansion of natural gas service, any subsidies enacted to promote the extension of natural gas service into unserved areas for social, environmental, or economic reasons should be transparent and collected from all taxpayers—not just utility ratepayers.

SB 32 Work Group Potential Actions

Although the SB 32 Work Group could not reach agreement on specific legislative recommendations to help facilitate the expansion of natural gas service, its members identified three potential actions to encourage service expansion into unserved areas.

1. Establish more liberal distribution extension policies in which existing customers pay for a larger share of the costs of a service extension project.

In general, the SB 32 Work Group agrees that construction allowance formulas should reflect the system benefits that accrue to existing customers over the life of a project. The natural gas utilities have the ability to seek changes to their extension policies and provide justification for those changes. These projects would not affect pipeline extensions but could provide additional distribution-level expansion.

2. Impose surcharges on new customers commensurate with the benefits they receive from getting access to natural gas service.

In general, the SB 32 Work Group agrees that new customers in a previously unserved area should help pay for a distribution expansion consistent with the benefits they receive from getting access to natural gas service.

3. Seek alternative sources of funds for projects.

Funding beyond what legitimately can be picked up by new and existing customers will be necessary to cover the costs of large, new gas service extensions. As listed above, the SB 32 Work Group identified a number of potential untapped sources that could be used to help fund projects.

The SB 32 Work Group also believes that service extension projects would greatly benefit from an individual or organization responsible for identifying and securing external funding for the projects. Without such a coordinated effort to secure outside funding, most projects will be shelved.

Although the SB 32 Work Group did not reach a consensus on possible legislative actions to provide additional funding, its members did discuss the following possible proposals:

1. Allocating general fund or lottery funds to natural gas system expansions.
2. Redirecting some portion of Oregon Health Authority funds to natural gas system expansions.[2]
3. Redirecting funding used for air quality improvement such as reducing emissions from wood stoves to natural gas system expansions.
4. Providing state loan or bond guarantees for expansion projects.[3]
5. Directing Business Oregon to identify and coordinate other sources of funding for natural gas system expansion projects.

[2] This redirection of funds might be justified based on the premise that the availability of natural gas will promote economic development, which, in turn, will reduce poverty and promote overall health in the region. Also, because the expansion of gas service would likely reduce wood heating, the redirection of funds might also be justified based on the purported link between air quality and health.
[3] These guarantees, which would result in decreased interest rates on loans or bonds, could be justified to improve economic development. Funding sources may include local bonds, Business Oregon loan/bond guarantees, lottery bonds, industrial development bonds, new natural gas public purpose charge funds, general fund moneys, lottery funds, Oregon Health Authority funds, etc.

SB 32 Work Group Conclusions

The SB 32 Work Group reached two primary conclusions:

Conclusion 1:

Potential changes to distribution expansion policies could increase the amount of ratepayer revenue to support the expansion of natural gas service territory. Although the PUC could approve such changes within its current statutory authority, these additional revenues are not likely to be sufficient to fully fund expansion to any city in Oregon that currently does not have natural gas service.

Conclusion 2:

Potential legislative action could provide additional revenue to support natural gas expansion. These actions include using funds from existing sources, such as the general fund, or creating new funding mechanisms, such as a service territory expansion surcharge on all natural gas customers. The diverse members of the SB 32 Work Group, however, do not agree on any legislative action to create this additional revenue. If such legislative action is taken, the SB 32 Work Group agrees such measures operate in a transparent manner.

Appendix A: Natural Gas Utilities' Proposal for Funding Mechanisms

September 15, 2016

Senate Bill 32
Study of Natural Gas Expansion to
Unserved Areas
2016 Report to the Legislative Assembly

EXPANSION OF NATURAL GAS IN OREGON – REGULATORY INITIATIVES/MECHANISMS

Through Senate Bill 32, the Legislative Assembly "finds and declares that having access to natural gas is in the public interest and that the extension of natural gas pipelines and other infrastructure necessary for providing natural gas to areas that do not have access to natural gas is necessary for the communities of this state to preserve local economies, enlarge tax bases and generate additional economic opportunities." (emphasis added)

In an effort to effectuate the findings of the legislature, and consistent with the authority already held by the Public Utility Commission of Oregon (PUC), **the LDCs recommend that the PUC adopt the legislative policy statement listed above as its own policy.**

The LDCs further recommend that the Commission support the following items, understanding that a combination of those items may be necessary to fulfill legislative intent:

1. **Line Extension Policy Modification** – Recognizing the benefits that natural gas can provide to areas that don't have natural gas today, filings from the natural gas Local Distribution Companies (LDCs) which use allowable investment methodologies may take into consideration the longevity of new customers on the system (such as the Perpetual Net Present Value methodology). Such filings would be expected to increase the level of allowable LDC investment above the current level, which hamper potential expansion opportunities.

2. **Natural Gas Expansion Tariff Rider** – Filings from the LDCs may be developed to include mechanisms through which amounts could be accumulated for the purpose of funding any shortfall that may exist between the estimated cost to provide service to a new community or development, and the allowable investment as calculated in the LDC's tariff. The determination of the level of funding, collection and allocation of funds, etc. would be included in the LDCs filing.

3. **Portfolio Treatment of Allowable Investment** – Some natural gas line extensions cost less than what the maximum allowable investment supports. To that end, filings by the LDCs may include an application of "banked" amounts of any unused portions of line extension allowances to help, in conjunction with other funding sources, to make uneconomic line extensions financially viable.

4. **Geographical Surcharges** – LDC filings may request geographic-specific surcharges or tariff riders applicable only to customers in communities where natural gas expansions have been made. These surcharges would be in addition to the LDC's Commission-approved rates. The additional revenue from the surcharge rate would be applied towards the revenues expected from a system expansion, and would assist in making the economics of the expansion more favorable.

5. **Customer Assistance** – Not only are the costs associated with providing service to new communities a matter that requires special attention and consideration, the costs on the

customer side of the meter also need to be addressed. To that end, the LDCs recommend that the Commission encourage LDC filings to assist customers with the cost of conversion. Below are two examples that provide customer assistance, and which have been employed in similar form by other jurisdictions:

a. Excess Line Extension Allowance – LDC filings may include programs to make available to new customers any excess line extension allowance in order to help offset the cost of natural gas space and water heating equipment.

b. Fuel Conversions & Electric Avoided Costs – Energy efficiency incentives promoting the conversion of space and/or water heat to natural gas, if cost-effective as measured under the total resource and utility cost tests. Any potential rebates would further help to offset the costs associated with the conversion to natural gas consistent with legislative intent.

Appendix B: Pacific Propane Gas Association Comments

September 15, 2016

Senate Bill 32
Study of Natural Gas Expansion to
Unserved Areas
2016 Report to the Legislative Assembly

Comments of the Pacific Propane Gas Association
On Proposal by the Northwest Gas Association

The Pacific Propane Gas Association (PPGA) appreciates the opportunity to present its views on the issues being considered by the Senate Bill 32 natural gas work group. PPGA here offers specific comments on the proposal distributed by the Northwest Gas Association (NWGA) at the meeting of the work group on May 5, 2016.

PPGA disagrees with the reading given to Senate Bill 32 by NWGA. NWGA essentially argues that the legislature has already determined that Oregon's natural gas systems should be expanded and that the Public Utility Commission is charged with making it happen. Instead, the legislature has recognized the benefits of natural gas as a fuel and required the Public Utility Commission to convene a work group to solicit input and to explore means by which natural gas service might be made more available to consumers. A number of issues are identified for the work group to address, and the final product is a report to the legislature—not a plan for expanding the natural gas network. Had the legislature intended to mandate that the state's natural gas system be expanded and that the Public Utility Commission be the instrumentality for doing so, it certainly could have, and would have, stated this.

Line Extension Policy Modification. As the work group knows, PPGA believes that natural gas expansions that are not economic run counter to sound public policy if they are subsidized by either taxpayers or existing captive natural gas customers. Utility shareholders, who have decided not to deploy their own capital, should not be subsidized by either taxpayers or captive utility customers. On the other hand if utility shareholders do desire to put their capital at risk in financing an expansion, then PPGA can interpose no objection.

In one fashion or another determining whether a proposed expansion is economic requires comparing anticipated delivery revenue from the expansion with the costs of constructing and operating it. There are a number of analytical tools for doing so, but they all essentially compare the delivery revenue stream with the costs.

PPGA does not offer any specific guidance with respect to modifying existing line extension policy, but it should not be used as a tool to predetermine the outcome of line extension proposals. The apparent suggestion by NWGA that the revenue stream in perpetuity be used as the basis for analysis would appear to be a mechanism to predetermine the outcome. Business decision-makers do not make investment decisions on the basis of possible perpetual revenue streams for assets. Rather, any line extension policy should track the models that managers employ in determining whether it is economic for the utility to deploy its shareholders' capital. Utilities should not be permitted to use one form of analysis for its shareholder investments and a different one for assessing potential line extensions.

Natural Gas Expansion Tariff Rider. NWGA speaks of methods by which funds "could be accumulated" to cover any future shortfall in revenues from a proposed expansion. The NWGA paper is vague on this point, but presumably such a mechanism would include surcharging existing customers in order to develop a pot of dollars to fund line extensions. Or it might include directing pipeline and supplier refunds or refunds ordered by the Public Utility

Commission itself to a reserve to fund line extensions. Any such mechanism would be a wolf in sheep's clothing, as such refunds would ordinarily be distributed to the customers that paid these costs in the first instance. Again, although the NWGA paper is vague, in all likelihood these mechanisms would be shell games, played with other peoples' money.

Portfolio Treatment of Allowable Investment. Admittedly where significant numbers of prospective customers are involved it may not be efficient to assess the economics of serving each new customer down to the nickels and cents. Nevertheless, a portfolio approach can result in material subsidization between different groups of prospective new customers. Should a portfolio approach be adopted the Commission should design it carefully so that cost-causation principles are observed.

Geographic Surcharges. NWGA suggests that "geographic surcharges" might be employed to promote system expansion. PPGA does not oppose surcharges to new customers so that the total revenue from those customers covers the total cost of serving them. PPGA would, however, object to a "geographic surcharge" under which existing utility customers in a geographic area would subsidize service to new utility customers in that or another region.

Customer Assistance. NWGA suggests that the Commission consider assistance to new customers in making a conversion to natural gas. In most circumstances this would address piping in the home and either conversion or replacement of appliances. The Commission should not entertain any suggestions of this nature, which call for yet a further customer subsidy. Experience has shown that customer conversion/replacement costs can run in the vicinity of $4,000-10,000 per home. The existing customers of the utility (some of which have certainly paid for their own conversion costs) should not be assisting new customers to install piping and appliances in their homes. Should the Commission entertain such a proposal, it should also extend it to the customers of competing energy sources such as propane.

NWGA speaks of making "excess line extension allowances" available to new customers to fund piping and appliances. Line extension allowances are essentially grants from existing customers to new customers. Making them available to new customers for conversion costs would simply represent one more tax on existing natural gas customers to subsidize both new customers and utility shareholders.

NWGA also speaks of using energy efficiency credits to fund conversion costs. Propane, like natural gas, when employed in direct flame applications, is more efficient than comparable electric applications. If the Commission entertains utilizing energy efficiency credits for natural gas conversion, it should also adopt a similar program for new and existing propane customers, who help reduce the state's demand for electricity.

Appendix C: First Meeting Presentations

September 15, 2016

Senate Bill 32
Study of Natural Gas Expansion to
Unserved Areas
2016 Report to the Legislative Assembly

Gas Distribution Development

Prepared by the Oregon Public Utility Commission

SB 32 Work Group Shall Study

a) The commission's policies regarding the extension of natural gas mains;

b) Mechanisms for funding the expansion of natural gas services, including the use of tariffs, the imposition of charges and fees, the use of unclaimed refunds and the establishment of accounts dedicated to the expansion of natural gas services;

c) The submission of recommendations by public utilities that furnish natural gas;

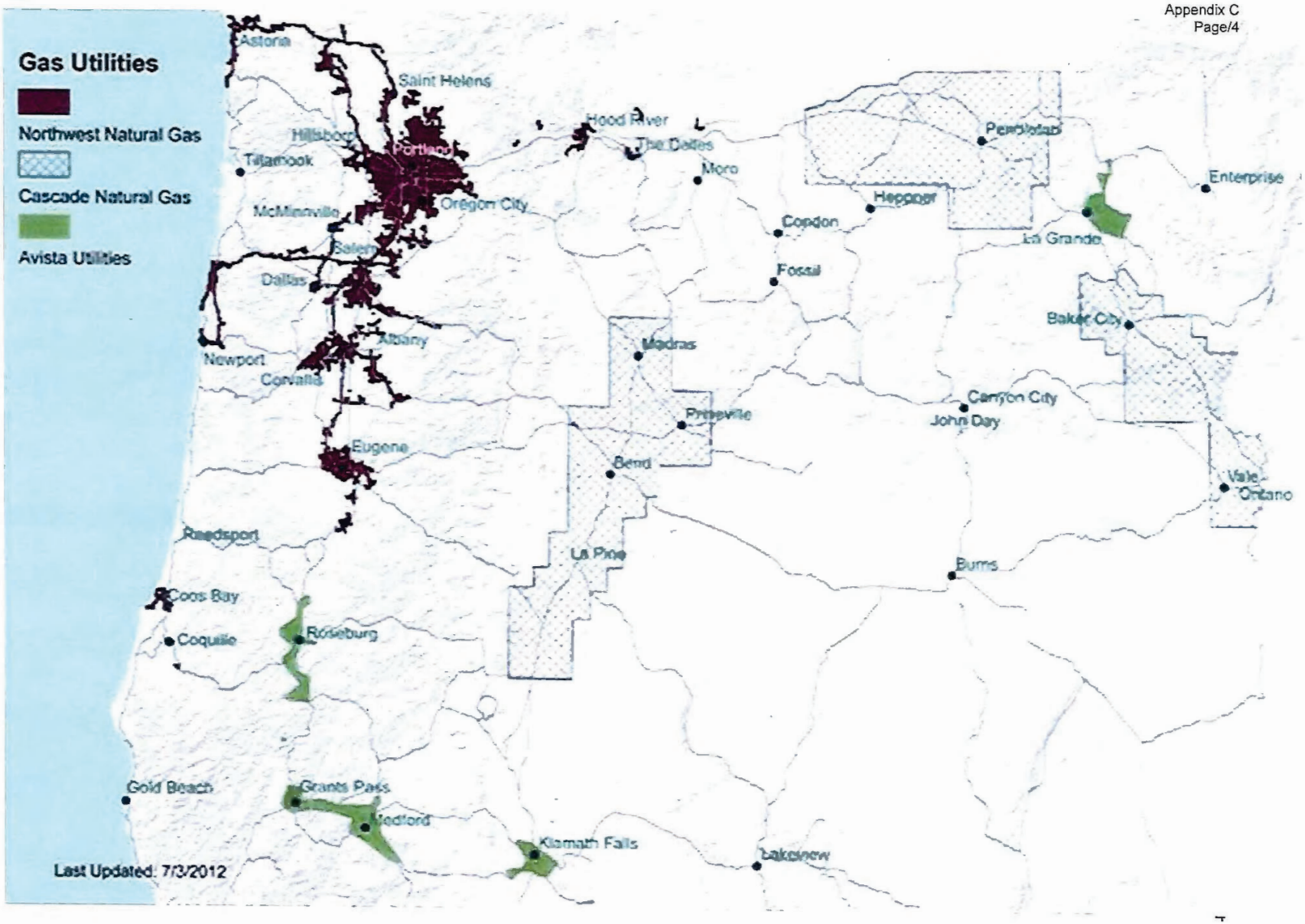
d) Possible processes for including in a public utility's rates the cost of projects involving the extension of natural gas pipelines and other infrastructure necessary for providing natural gas;

e) Possible selection criteria for projects involving the extension of natural gas pipelines and other infrastructure necessary for providing natural gas; and

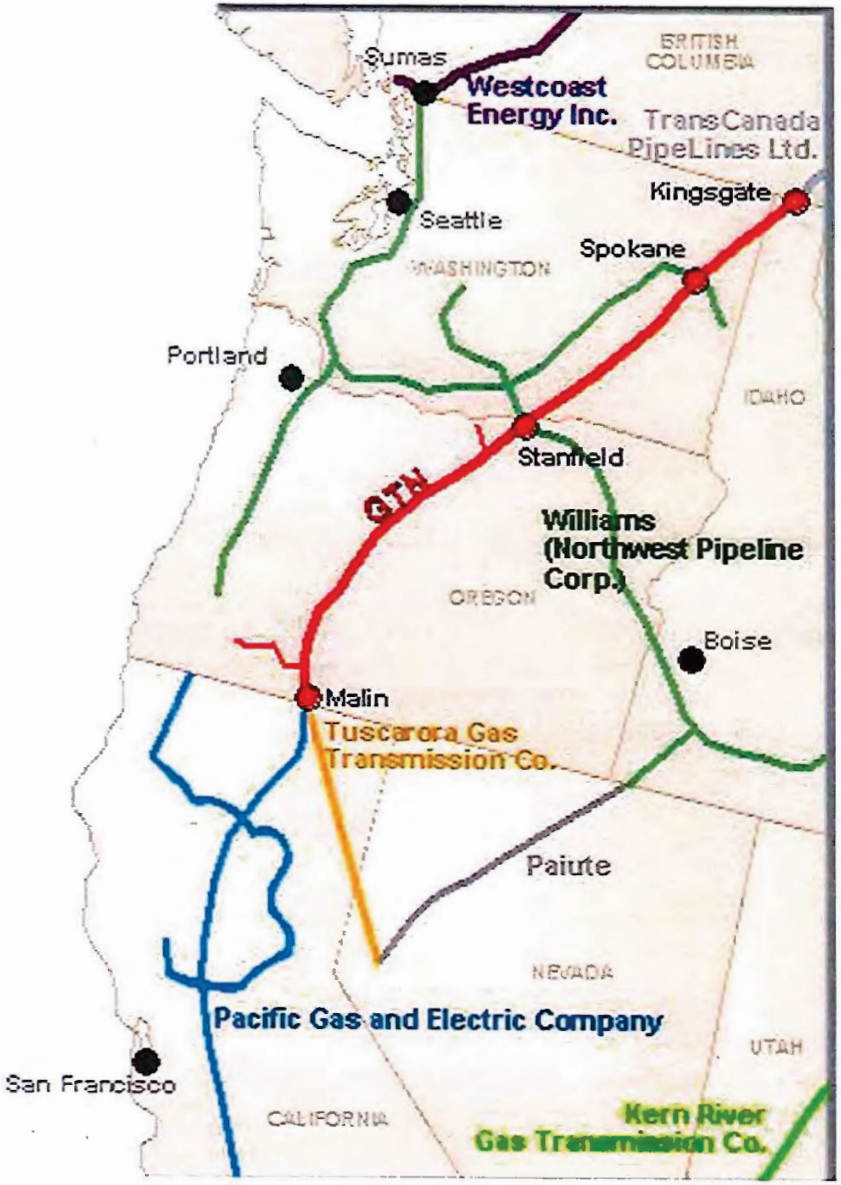
f) The potential rate cap for projects involving the extension of natural gas pipelines and other infrastructure necessary for providing natural gas.

Unserved Communities

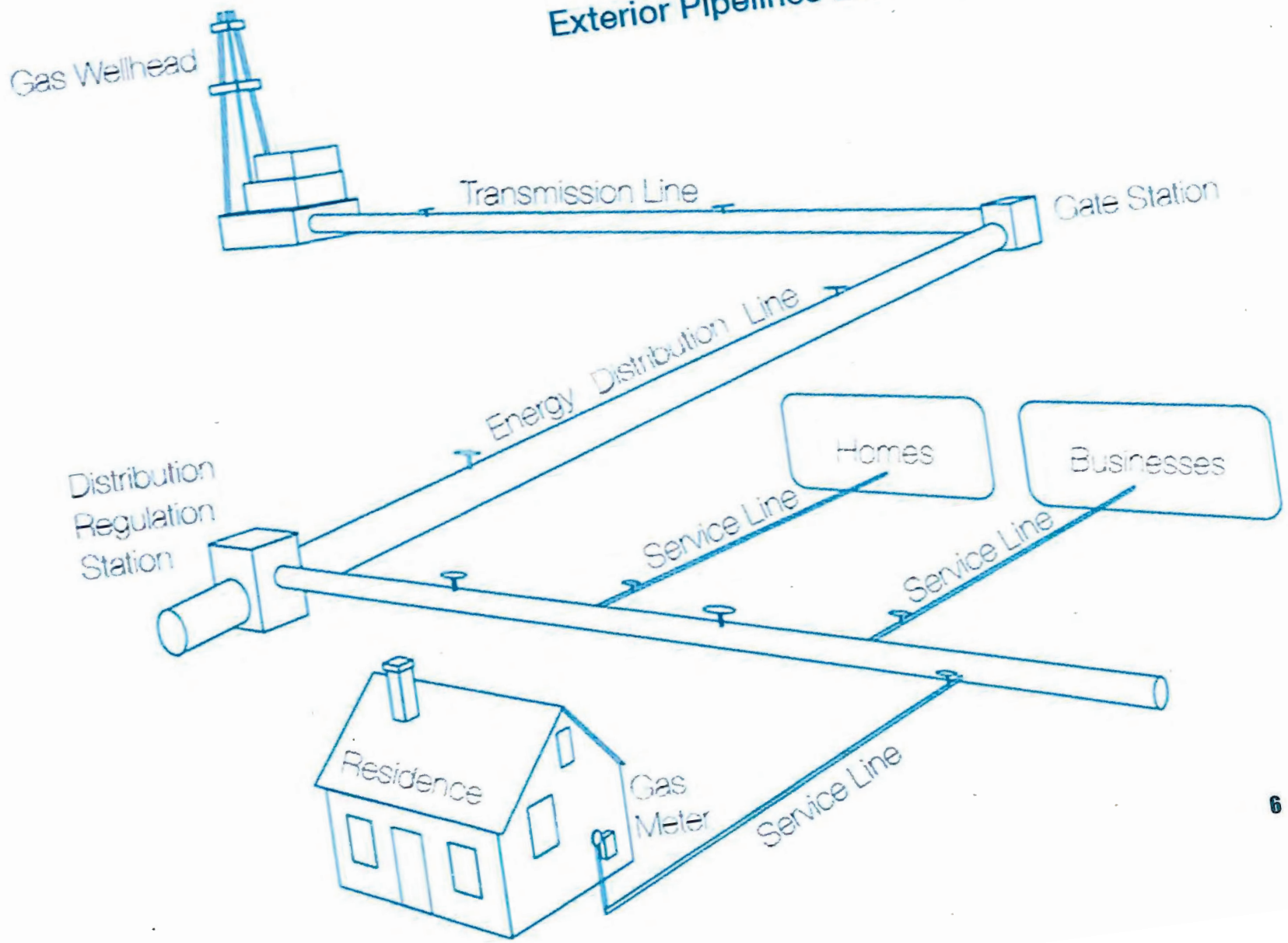
- Oregon has many communities without access to natural gas
  - Small population
  - Low housing density
  - Far from existing transmission or distribution
- These communities rely on alternate energy sources for heating and industry


Gas Utilities
Northwest Natural Gas
Cascade Natural Gas
Avista Utilities
Last Updated: 7/3/2012
Astoria
Saint Helens
Hillsboro
Portland
Tillamook
McMinnville
Oregon City
Salem
Dallas
Albany
Newport
Corvallis
Eugene
Reedsport
Coos Bay
Coquille
Roseburg
Gold Beach
Grants Pass
Medford
Klamath Falls
Lakeview
Hood River
The Dalles
Moro
Condon
Fossil
Heppner
Pendleton
La Grande
Enterprise
Baker City
Madras
Prineville
Bend
La Pine
Burns
Canyon City
John Day
Vale
Ontario

Western Pipeline Grid Map

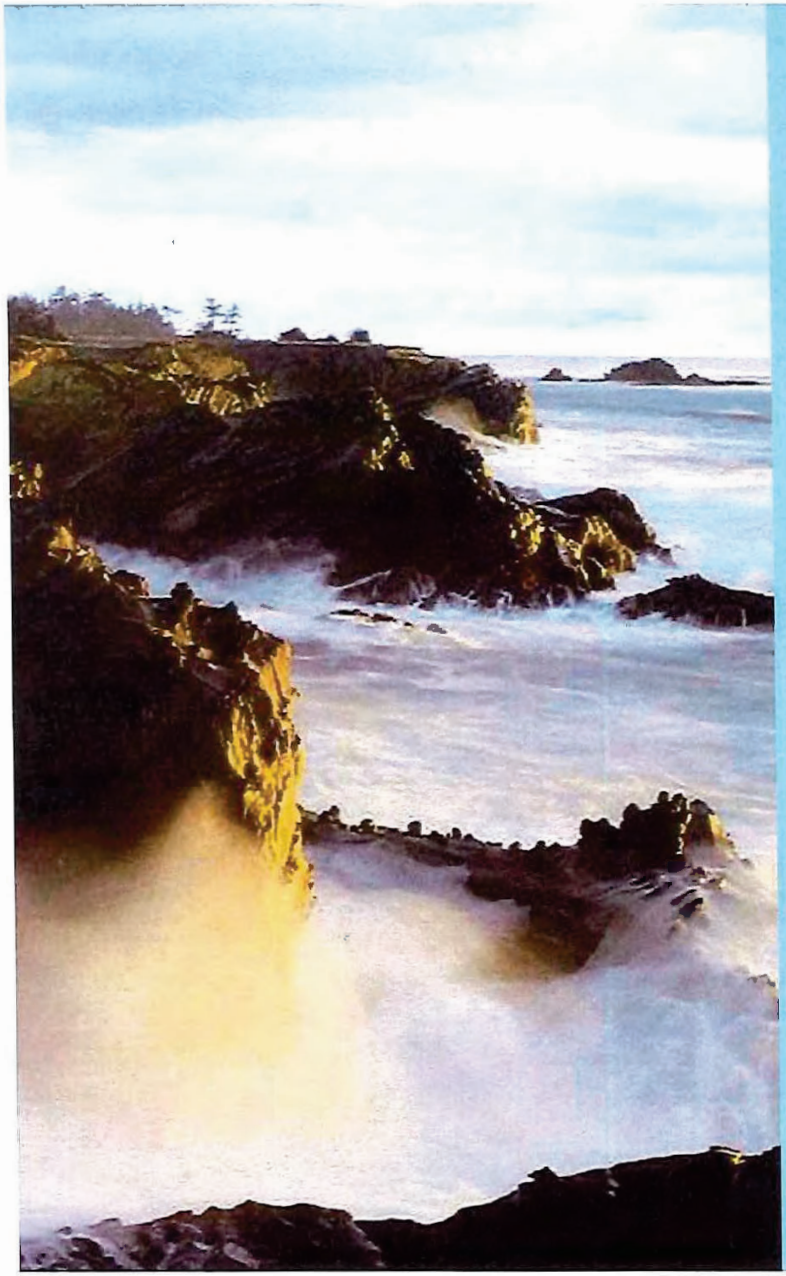


Exterior Pipelines Leading to the Home



SB 32 2(1)(a) Commission Policy

- General expansion of the system
  - Large project to build in new communities
  - Addressed in general rate case
  - Investment subject to prudency review
  - E.G. Coos Bay
- Extensions to specific properties
  - Small incremental investment within existing community
  - Governed by line extension policy in LDC Tariff
  - E.G. Industrial and residential service connection



General Expansion:

Coos County

- Community Financed Pipeline
- NWN Financed Local Distribution
  - NWN Rates Increase in next GRC
- Coos Customers Pay Surcharge

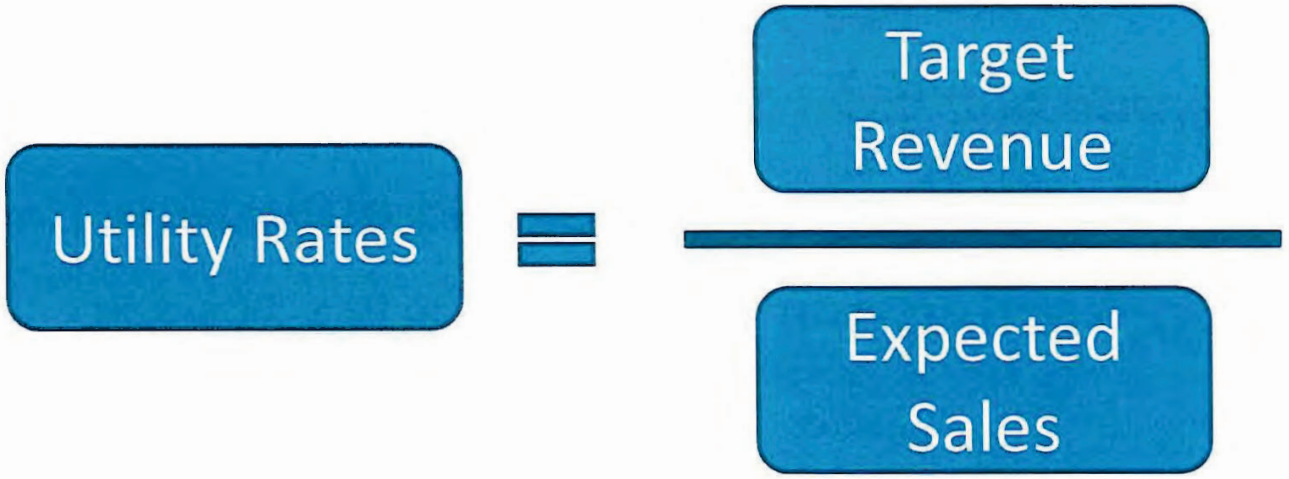
Specific Property Extension:

- Utility pays share of cost based on expected revenue
- Applicant covers remaining cost
- Applicant is reimbursed as neighbors connect
- Utility's share of costs are incorporated into rates in next GRC

General Rate Case

- Review expected annual expenses for utility
- Determine fair return for utility investors
  - Identify value of used, useful, and prudent investment
  - Identify market based cost of equity
- Set utility rates such that utility earns the fair return

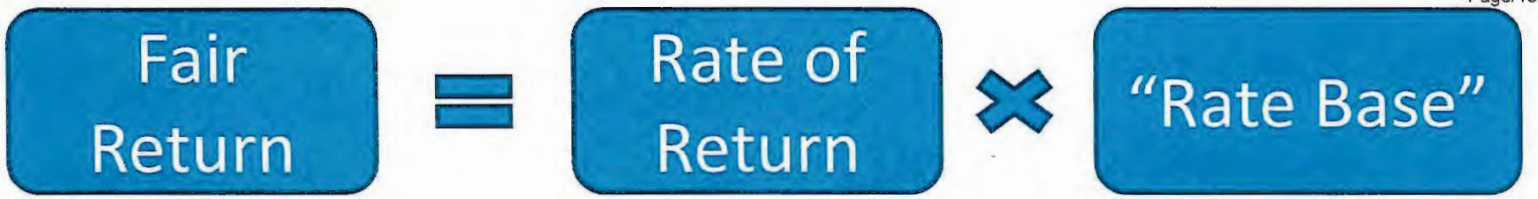
Target Revenue
=
Expected Cost
+
Fair Return


Utility Rates
=
Target Revenue
Expected Sales

Expected Costs

- Labor
- Transmission charges
- Storage Expenses
- Maintenance and Repairs
- Overhead
- Depreciation

❖Natural Gas Cost is Pass Through Expense

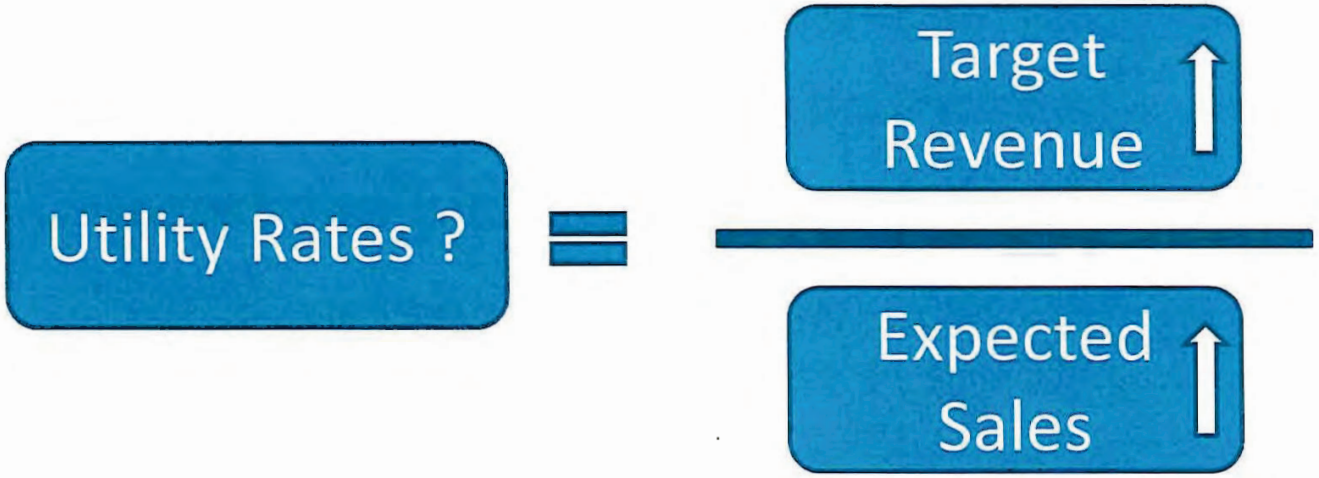


- Rate of Return is a market estimate for investments of equivalent risk
- Rate Base is the amount of investment that is allowed to earn a return
  - Includes used and useful assets
  - E.G. Transmission Pipe and Combustion Turbines
  - Costs for assets must be prudent
  - Total amount excludes accumulated depreciation

Rate Effects of Prudent Expansion

- Sales increase over time
- Ratebase increases
  - Return to shareholder increases
- Operating Expense Increases
- Impact on existing customers is ambiguous

Target Revenue
=
Expected Cost
+
Fair Return


Utility Rates ?
=
Target Revenue
Expected Sales

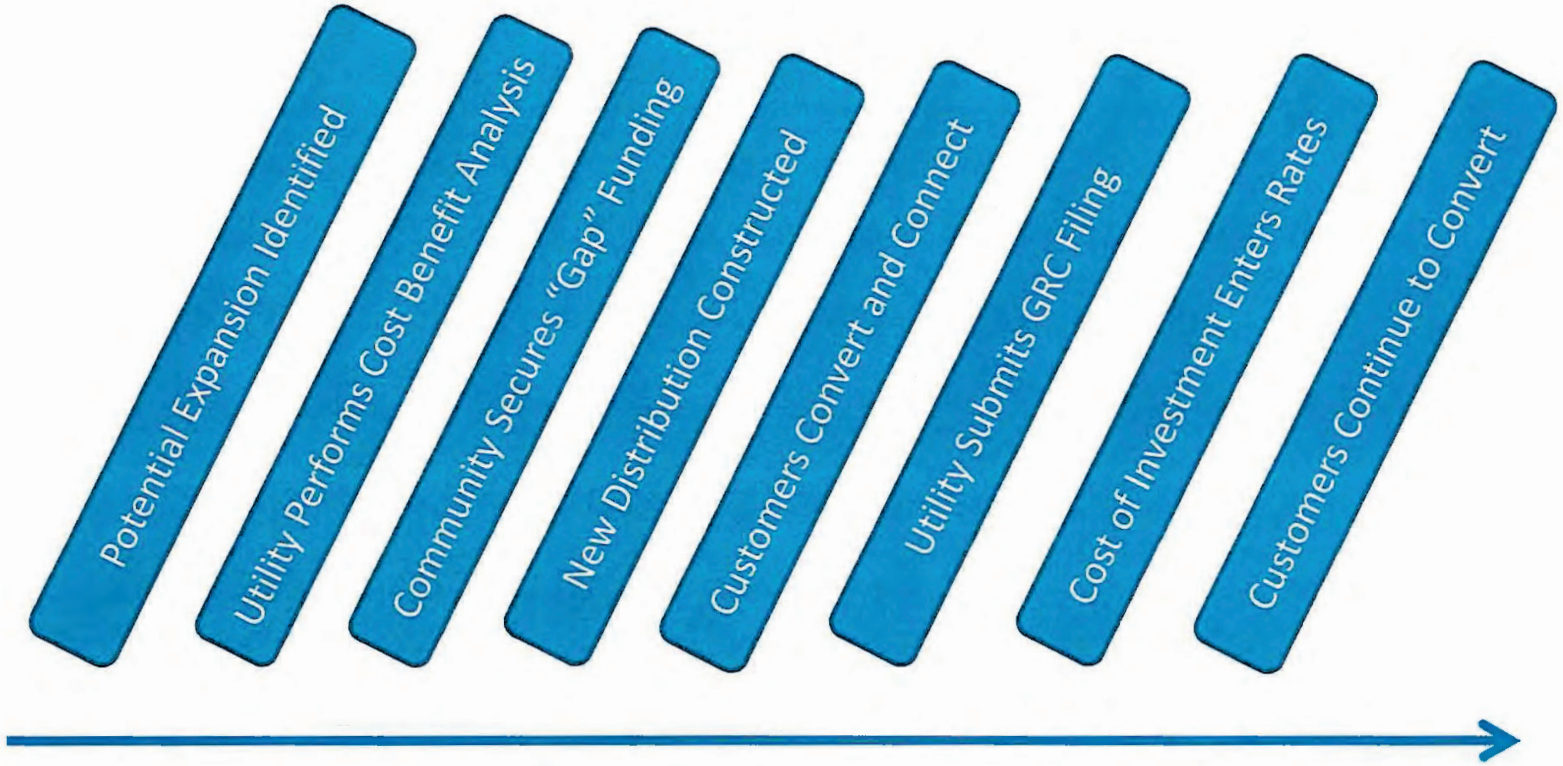
Goals of Regulation

- Provide safe and reliable service
- Reproduce efficiencies of competitive markets
  - Utilities operate in efficient, least cost method
- Customers are responsible for the costs that they cause (I.E. avoid subsidies)

Prudency Review

- Promote efficient operations and investments
- Given the information available at the time, the investment was in the best interest of ratepayers:
  - Benefits (as gas customers) exceed costs
  - Existing customers are not harmed
  - Does not weaken the financial stability of Utility
- Construction costs were properly managed
- Does not evaluate external costs and benefits

Timeline for Distribution Expansion



When the "utility" pays for expansion:

- Shareholders bear the annualized cost until the next rate filing.
  - Utility shareholders bear timing risk.
- Existing customers bear the cost of approved investment after the next rate filing.
  - Utility shareholders earn return on approved investment.
  - Any associated increase in rates represents a subsidy of new customers by existing customers.

Economical Distribution Project

- Distribution projects are economical if the present value of all the future benefits is greater than the present value of costs.

- If the costs of a project are high and the benefits are low, the project will not add value to society.

Example of inefficient expansion

- Potential customer has a long driveway that crosses a stream.
- Annual savings for natural gas vs propane: $1000
- NPV of savings @ 10% discount rate: $10,000
- Cost to connect and convert to natural gas: $15,000*
- Value of expansion: Loss of $5,000

* After accounting for contribution to fixed cost imbedded in utility rates.

Cost Causer Cost Payer

- Efficient
  - If customer expansion is subsidized the cost may be more than the benefit
- Fair
  - If customer expansion is subsidized by existing customers, existing customers pay twice

Expansion Question Implicates Additional Societal Impacts

- Environmental Impacts
- Economical Development
- Impact on Existing Energy Providers
- Effect on State Agencies
- Long Term Gas Supply and Interstate Pipeline Capacity

Avista Line Extension Policy

January 26, 2016

Current Line Extension Policy

Allowances – How much can Avista invest in a line extension

- Present Methodology - 3x estimated annual revenue from customers
- Allowance is approximately $2,000 for residential customers; C&I allowances determined on a "site-specific" basis.
- Allowance starts at the service line to the premise, and then is applied "upstream".
- Analysis for serving new communities factors in all of the various potential allowances for financial feasibility studies

Current Line Extension Policy

Costs – there are many costs that affect line extension economics:

- New development or existing streets (e.g., pavement cuts)
- Type of soil (sandy, basalt, etc.)
- Distance to existing natural gas infrastructure
  - Distance to natural gas main
  - Distance to support personnel, local reps, office space, etc.
- Is an interstate pipeline tap required

Current Line Extension Policy

Line Extension Allowance Discussion – should new customers:

- Subsidize existing customers
  - Less allowance to new customers
  - New customer revenue helps cover costs of existing customers

- Be rate neutral
  - Could justify a larger allowance (Avista's Washington filing – Perpetual Net Present Value Methodology)

- Be subsidized by existing natural gas &/or electric customers
  - Environmental benefits of natural gas
  - Direct Use vs. Turbine – more efficient
  - Regional View - Natural Gas is the incremental electric resource.
  - Avista electric DSM in Washington & Idaho provides conversion incentives

NW Natural – Oregon
Schedule X Applicant requested gas service

RESIDENTIAL:

- Existing main:
  - Fixed revenue allowance based on installed equipment per Tariff
  - System average service line installation cost
  - Applicant pays any difference ("contribution") between revenue allowance and installation cost
    - Installs for gas furnace typically do not require contribution
  - No refund on any construction contribution payments

- Main Extension:
  - Company uses same revenue allowance as existing main installations
  - Installation cost based on site-specific cost estimate
  - Applicant pays any difference between revenue allowance and estimated installation cost
    - Revenue allowance typically does not cover any main extension costs
  - Customer receives potential refund should additional hook ups occur on the main extension within three years from install date

NON-RESIDENTIAL:

- Revenue allowance based on 5X estimated gas use for installed equipment type and equipment operational ratings
- Site-specific costs for both main extension and service installations
-

NEW COMMUNITIES:

- Investment decision would be based on a financial model that would estimate the average return on the investment given cost and estimated potential revenue to be expected from the investment
- Service line and in-community main extensions would use Schedule X criteria for each actual customer hook-up.

Current Line Extension Policy

- Service Lines at No Direct Cost
  - Space Heat Only — 20 Feet
  - Space and Water Heat — 40 Feet
  - Large C/I with >150,000 BTU load — 40 Feet

- Mains Extensions
  - The Company provides an allowance based on 4.5 times the customer's forecasted annual margin (distribution revenue and basic charge)
  - Costs beyond this allowance must be paid upfront by the customer
  - If the customer forecasted load does not develop in six months, the Company shall bill the Company for the costs of the main extension.

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A Subsidiary of MDU Resources Group, Inc.

Line Extension Costs

- Average length of service line
  - 43 feet
- Average cost for a new service line (not main)
  - $1666
- Note: This is a system average for customers who did not find first costs to be prohibitive.

CASCADE NATURAL GAS CORPORATION®
A Subsidiary of MDU Resources Group, Inc.

Unintended Consequences

The Policy upholds the principles of cost causation, ensuring installed pipe is "used and useful", and in doing so creates the following barriers to connecting to gas:

- Prohibitive first cost barrier to connect (service line, main extension, and appliances)
- Lost opportunities to serve areas. Pockets of unserved areas in urban communities develop that are difficult and costly to backfill.
- The policy is designed to look at one customer at a time rather than the potential of a community.
- Serving isolated communities is nearly impossible without a signed commitment to connect and unique cost recovery through a property tax or city-specific rate.

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State Energy Facility Siting

SB 32 - Workgroup

January 26, 2016

Todd Cornett, Assistant Director
Oregon Department of Energy

OREGON DEPARTMENT OF ENERGY

State Energy Siting Basics

- Energy Facility Siting Council (EFSC)
- Oregon Department of Energy Staff
- Consolidated Review Process
- Standards Based Process
- Site Certificate
- Application Fees

OREGON DEPARTMENT OF ENERGY

Jurisdiction

- State - ORS 469.300(11) "Energy Facility" definition – creates state threshold
- Local: facilities smaller than state "Energy Facility" definition
- Federal: Federal Energy Regulatory Commission (FERC)

OREGON DEPARTMENT OF ENERGY

Gas Pipeline Energy Facilities

- 469.300(11)(a)(E) A pipeline that is:

(i) .....

(ii) At least 16 inches in diameter, and five or more miles in length, used for the transportation of natural or synthetic gas, but excluding:

(I) A pipeline proposed for construction of which less than five miles of the pipeline is more than 50 feet from a public road, as defined in ORS 368.001; or

(II) A parallel or upgraded pipeline up to 24 inches in diameter that is constructed within the same right of way as an existing 16-inch or larger pipeline that has a site certificate, if all studies and necessary mitigation conducted for the existing site certificate meet or are updated to meet current site certificate standards; or

(iii) .....

OREGON DEPARTMENT OF ENERGY

Gas Pipeline Exemptions

- OAR 345-015-0350(2) – A site certificate is not required for construction or expansion of any interstate natural gas pipeline or associated underground natural gas storage facility authorized by and subject to the continuing regulation of the Federal Energy Regulatory commission or successor agency.
- OAR 345-015-0370 – Consideration of Request for Exemption

OREGON DEPARTMENT OF ENERGY

EFSC Process

- Applicant submits a **Notice of Intent (NOI)**
- ODOE issues a **Project Order**
- Applicant submits an **Application (pASC)**
- ODOE deems the application complete
- ODOE issues a **Draft Proposed Order (DPO)**
- **DPO Hearing**
- ODOE issues a **Proposed Order (PO)**
- **Contested Case**
- EFSC issues a **Final Order/Site Certificate**
- **Appeal to Oregon Supreme Court**

OREGON DEPARTMENT OF ENERGY

Siting Division Staffing

- Fee for service – Staff increases and decreases based on volume of applications.

- Lead time for hiring new staff
  - E-Board or Budget Process
  - Recruitment
  - 6 – 12 Months to train Siting Analysts to function efficiently and independently.

OREGON DEPARTMENT OF ENERGY

Questions???

OREGON DEPARTMENT OF ENERGY

Appendix D: Second Meeting Presentations

September 15, 2016

Senate Bill 32
Study of Natural Gas Expansion to
Unserved Areas
2016 Report to the Legislative Assembly

SB32
Coos Bay Extension Review

Presented to SB 32 Workgroup
March 31, 2016

NW Natural®

Overview of Presentation

- Project drivers and funding streams
- Stipulation
- Timeline of project
- System development priorities
- Economic factors
- Customer growth
- Lessons learned

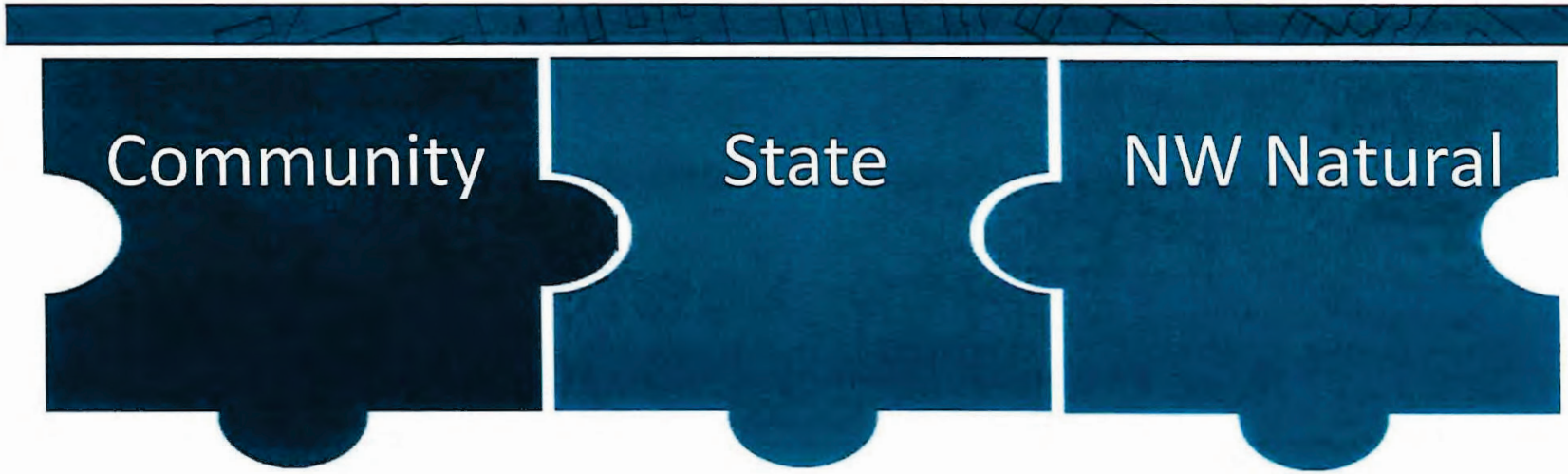
NW Natural®

Project Drivers

- Community needed economic development tools
  - Unable to attract new large commercial/industrials without natural gas service
  - Wanted to help businesses be competitive
- State wanted to support economic development
  - South Coast area had been economically depressed for years
- OPUC wanted to support expansion efforts while minimizing cross subsidization
- NW Natural wanted to support expansion to a new community

NW Natural®

Funding Streams



- $27M in local bonds
- $0.02/therm rider paid for by each new gas customer

- $20M lottery bonds
- $4M in studies to support project

- $12M approved by OPUC
- $500,000 shareholder contribution

NW Natural®

OPUC Stipulation Summary

- Project capital limit of $12 million
- Defined construction period
- Company capital contribution of $400,000
- 2 cent per therm adder
- Evaluation term of 20 years

System Development

- Top priority: Build system backbone to serve commercial and industrials
  - Used field surveys to locate commercial and industrial prospects, which drove backbone investment
  - Residential was secondary, when feasible
- Local team used a combination of marketing and advertising support
  - Public meetings to describe project and answer questions
  - Mail surveys - dual purpose of generating pre-construction interest and assessing consumer willingness to convert to gas
  - Direct mail, print and radio advertising and media outreach
- System backbone largely in place by end of 2005
  - 97% of $12 million budget spent
  - 88% (64 miles) of planned distribution main constructed

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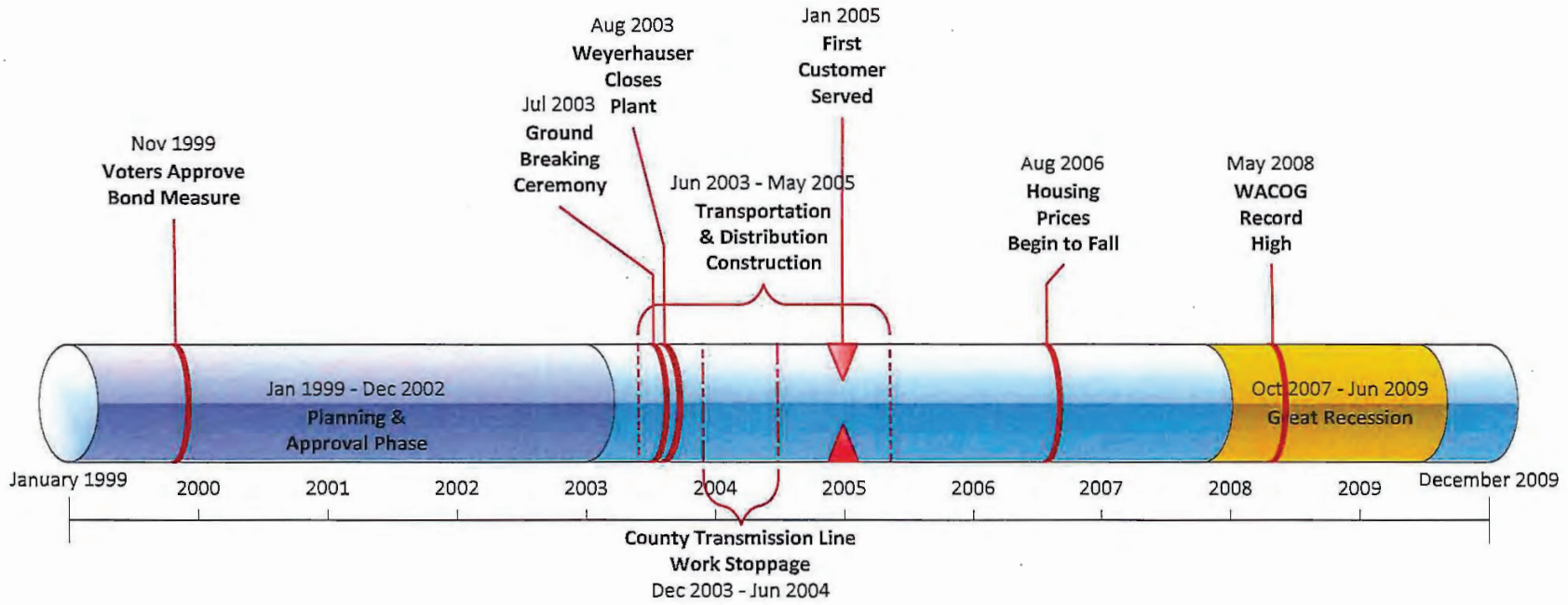
Timeline Factors



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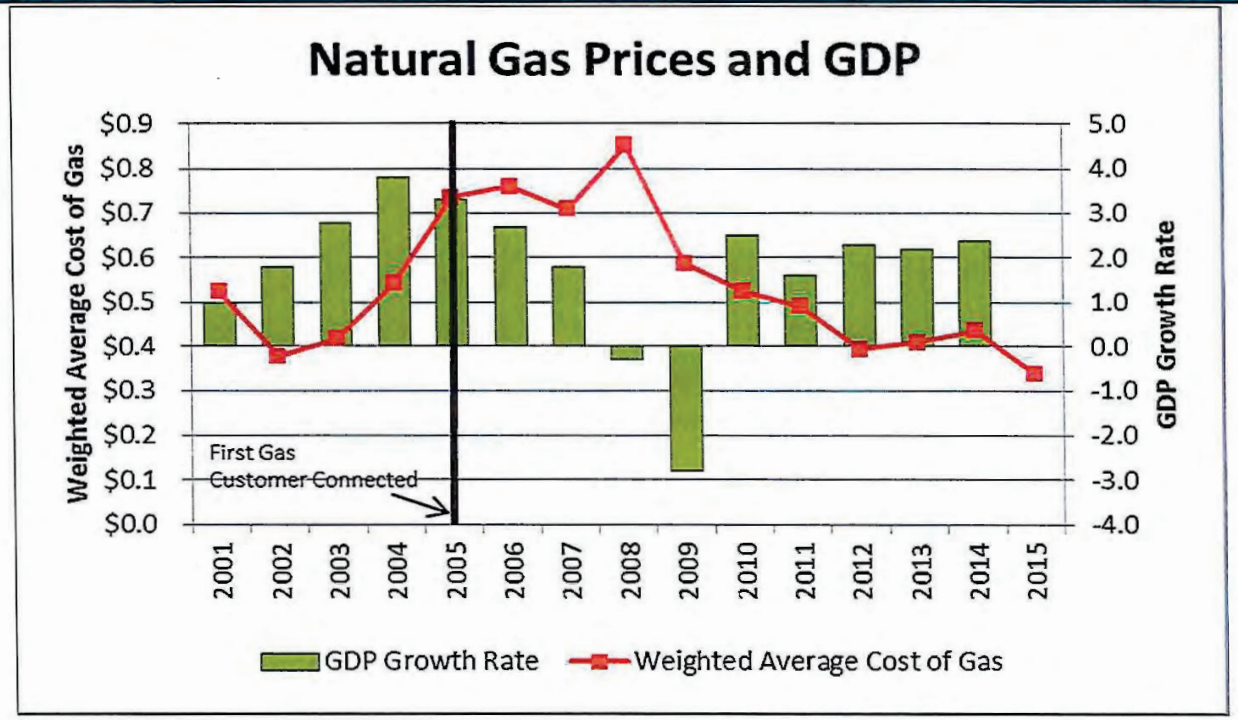
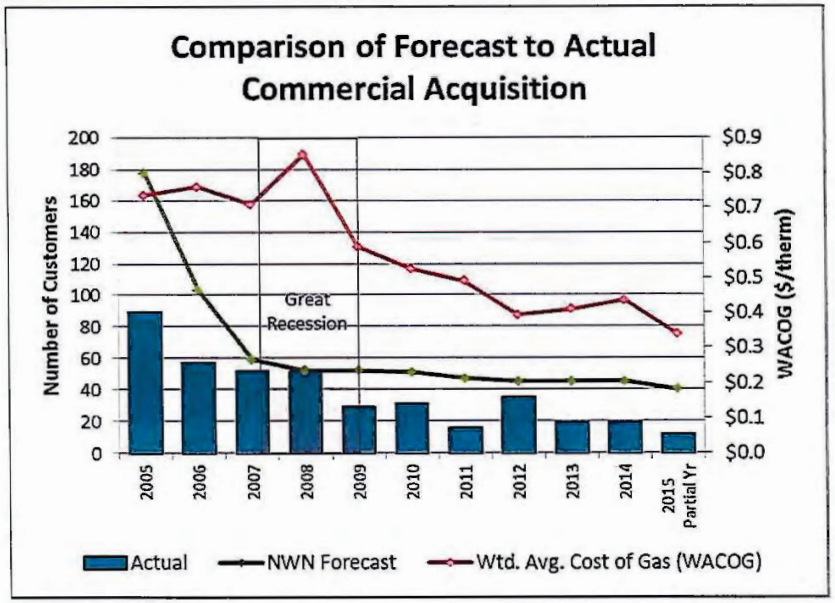
Gas Prices and the Economy

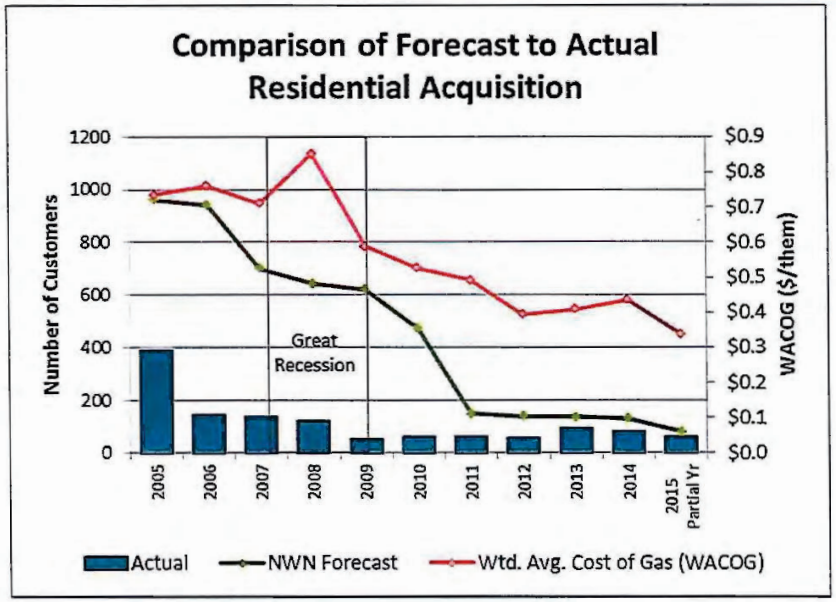


- Natural gas prices spike to record levels
- Great Recession hits, followed by slow recovery

NW Natural®

Forecast to Actuals





- Penetration of commercial and industrials largely tracks to forecast – coinciding with the strategic focus of economic development.
- First cost barrier significant for residential conversions, given traditional service line policy and economic demographics.

NW Natural®

County Conditions Still Difficult

- Coos County's lagging local recovery
  - Coos County household income 76% of Oregon average
  - Jan. 2016 unemployment of 6.5% vs. Oregon rate of 5.1%
    - Coos County unemployment rate peaked at 13.8% during the Great Recession in 2009
- Many existing businesses and houses small, often un-ducted
  - Wood is primary heating fuel in roughly 20% of homes
  - Electric wall furnaces prevalent
  - Economics of unsubsidized conversions that also require a service line contribution not viable
- Low volume construction and conversion work mean few qualified contractors and higher per unit costs for consumers

NW Natural®

On-Main Market Share: 2005–2014

- Commercial new construction - 50%
  - Smaller buildings hard to serve unless right on main with no adverse construction issues
- Existing commercial - 29%
  - First-cost prohibitive; hard to cost justify with small loads
- Single family new construction - 69%
  - 25% of new construction is < 1,400 sq. ft.
- Existing residential - 22%
  - First cost prohibitive

Gas Share of Businesses and Square Feet

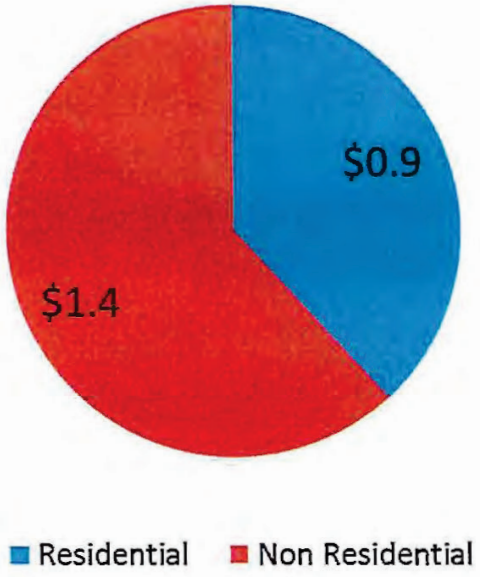
- Gas customers are twice as energy intensive as on-main non-customers
  - Gas customers tend to both larger and more energy intensive per square foot.
  - Gas serves a much larger percentage of business square footage than number of businesses.
- Conversion economics are more difficult for businesses with low potential gas usage per square foot

	Percent of Businesses		Percent of Square Feet	
	Non-Customers	Customers	Non-Customers	Customers
Commercial Schools	49%	51%	28%	72%
Commercial Hospitals	67%	33%	7%	93%
Commercial Other	70%	30%	68%	32%
Industrial	78%	22%	49%	51%

NW Natural®

Annual Energy Cost Savings

- Annual direct benefits from lower energy bills estimated at $2.3 million
  - Increased disposable income to residential customers
  - Higher profits for non-residential customers
- Does not include indirect benefits
  - Additional local spending by households and businesses results in higher local employment and incomes beyond the gas customer base.



NW Natural®

Lessons Learned

- Diversified funding streams coupled with regulatory support can make expansions happen.
- Expansions to promote economic development take a long-term view.
- Energy savings contribute to economic health of depressed communities.
- Early success can be affected by large anchor customers
  - Residential loads can grow slowly, and may not be enough
  - Contractual obligations could help bolster chances of achieving adoption rates
- An ongoing, coordinated economic development plan supported by all stakeholders may be beneficial
- Trade allies are a crucial link to customers
- Changes in the economy have a significant impact
- Conversions need robust first-cost reduction tools, and a longer-term view
- Looking at avoided costs may provide a new economically justified funding stream

NW Natural®

Thank you.

Lakeview, OR Natural Gas Expansion

March 31, 2016

Lakeview, Oregon

Quick Review from January Meeting

Allowances – How much can Avista invest in a line extension

- Present Methodology - 3x estimated annual revenue from customers
- Allowance is approximately $2,000 for residential customers; C&I allowances determined on a "site-specific" basis.
- Analysis for serving new communities incorporates all of the various potential allowances for financial feasibility studies

Current Line Extension Policy

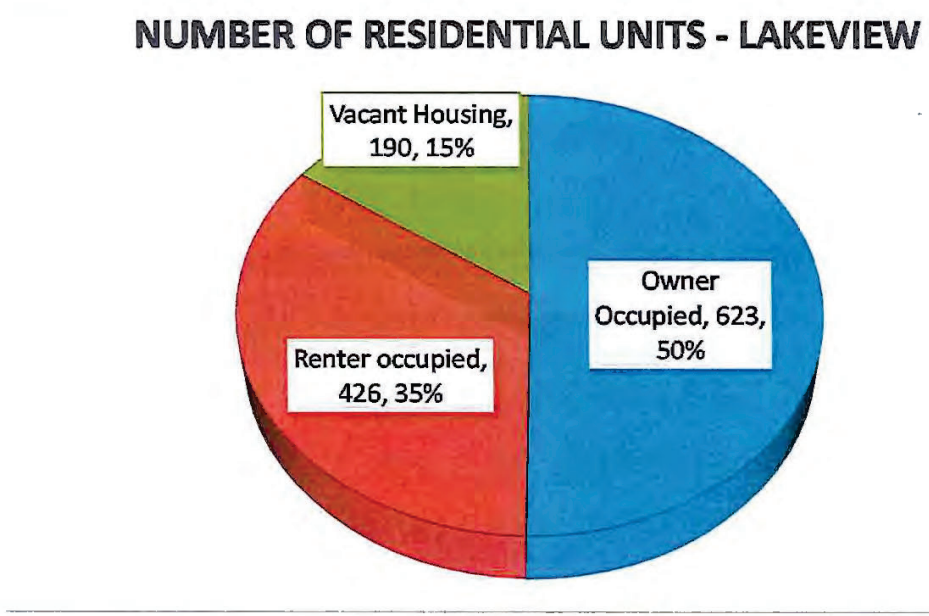
Costs – there are many costs that affect line extension economics:

- New development or existing streets (e.g., pavement cuts)
- Type of soil (sandy, basalt, etc.)
- Distance to existing natural gas infrastructure
  - Distance to natural gas main
  - Distance to support personnel, local reps, office space, etc.
- Is an interstate pipeline tap required?

Lakeview Economics under present Line Extension Policy

Residential Hookup Estimates

Median Housing Value	$ 89,216.00
Average Housing Value	$ 121,744.00



Avista Estimate – 125 homes out of 1,239 homes.

Lakeview Economics under present Line Extension Policy

Lakeview	Projected Customers	Total Therms Per Month Customer Class	Projected Annual therms 360 days	Rate per Therm	Total Annual Revenue
Residential Homes	125	46	69,000	$ 1.05307	$ 86,162
Commercial	50	194	116,400	$ 0.94626	$ 120,345
Large Commercial	3	5,000	180,000	$ 0.94626	$ 170,939
Totals	**178**	**5,240**	**365,400**		**$ 377,445**

3 Times Annual Revenue = $1.132 million allowance

Estimated Cost to Serve Lakeview

Cost to Build Project				
	Footage	Type	Total Cost	
Tap		Ruby	$	-
Regulation, Heating, Odorizing		Gate Stn & Reg Stn	$	606,586
High Pressure	10000	6" Steel	$	1,041,816
Distribution	42760'	6", 4" & 2" PE	$	6,340,039
Total cost to build Natural Gas System in Lakeview (including Tap)			**$**	**7,988,441**

Summary of Lakeview Economics

Cost to build based on Avista Engineering estimates	$	7,988,441
Revenue allowance based on OPUC Tarriff	$	(1,132,336)
Cost for Avista Local Rep. in Community (3 year offset)	$	750,000
State Contribution	$	-
Annual Reservation fees on Ruby Pipeline	$	106,331
Short on Contruction/Costs vs Revenue	**$**	**7,712,437**

How do we fill the gap?

Revised line extension tariffs:

Allowance Methodology Eff 3/1/2016 (WA)			
Residential Allowance	$	3,836	per customer
Commercial Allowance	$	5.10	per therm
Residential Allowance	$	479,500	
Commercial Allowace	$	1,511,640	
Total Allowance	**$**	**1,991,140**	

Result – 76% increase in allowance

How do we fill the gap?

Use a Long Term Time Horizon – factor in all housing?

Allowance Methodology Eff 3/1/2016 (WA)			
Residential Allowance	$	3,836	per customer
Commercial Allowance	$	5.10	per therm
Residential Allowance	$	4,756,640	
Commercial Allowace	$	1,511,640	
Total Allowance	**$**	**6,268,280**	

How do we fill the gap?

- Revised Allowance Methodology
  - approved in WA effective 3/1/2016
  - Incorporate Hookups Beyond 5 years
- State/Local Funding to Offset Capital Costs
- Locality Specific Surcharges
  - Need to be set at an appropriate level given fuel switching economics
- Electric to Natural Gas Fuel Switching Rebates
  - Behind the meter financial assistance
  - Changes in Avoided costs
  - Efficiency of Generation vs. Direct Use

Outline:

- Energy Source Overview
- Avista – Lakeview
- NW Natural – Coos County
- Key Takeaways

PUC Staff Observations

Energy Source Overview

- Census Bureau survey asks about residential primary fuel source for heating. Nationally about:
- 4% heat primarily with propane
- 5% heating oil
- 39% electricity
- 2% wood
- ~50% natural gas

EIA, "Short-Term Energy Outlook," March 8, 2016

Avista
Lakeview, OR Natural Gas Expansion

Economies of Scale with Population Density

Customer	Residential Households	Commercial	Large Commercial
Projected annual therms 360 days	69,000	116,400	180,000
Share of total	19%	32%	49%
		81%	

- **Lakeview projection**: Residential = **19%** of throughput
- **2014 Oregon Actuals**[1]: Residential = **36%** of throughput

[1](UG 288, Avista/700, Forsyth/5)

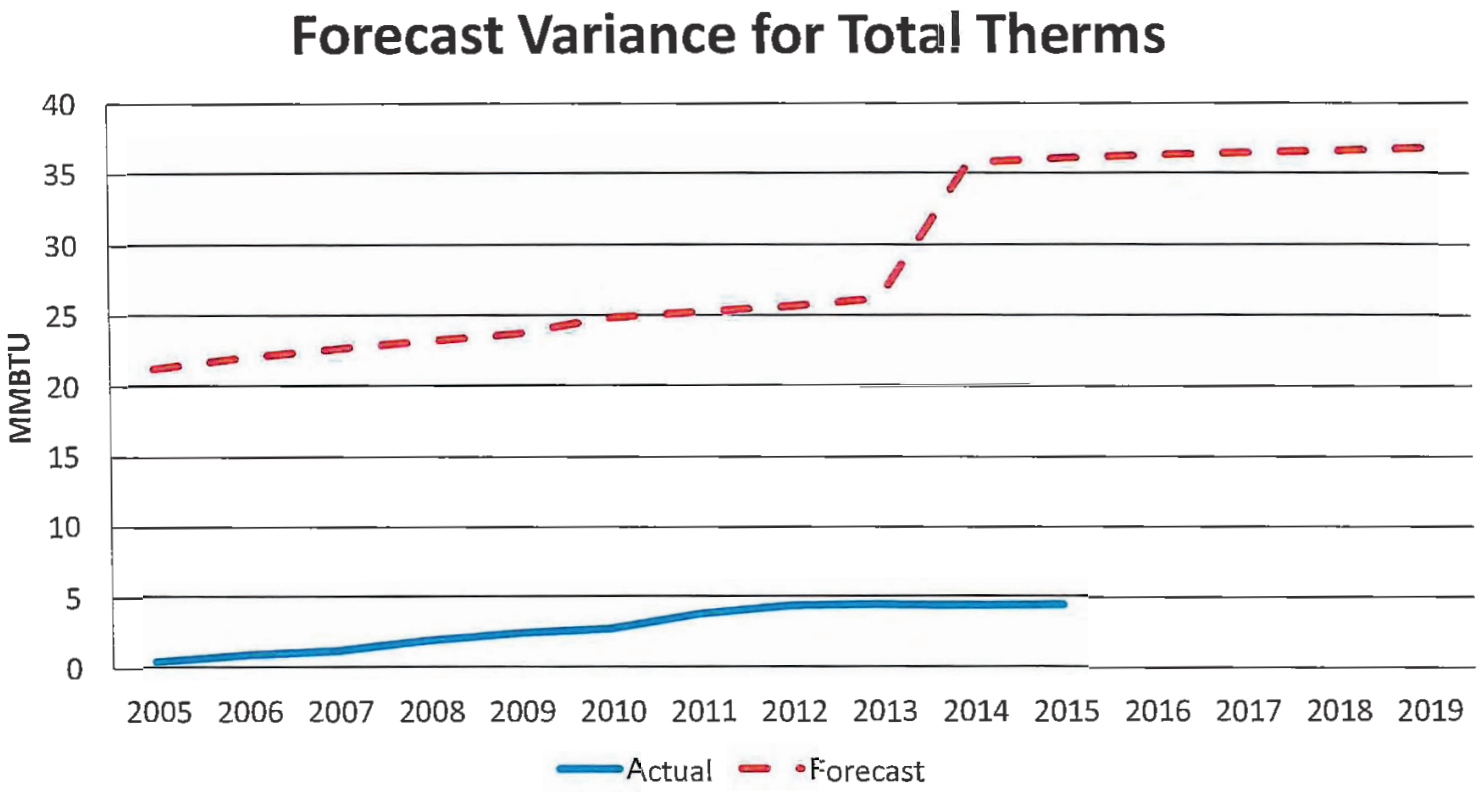
Forecasting Large Customers

- Importance of ensuring throughput
  - *The Oregonian/Oregon Live*, "Iberdrola Renewables told stakeholders in Lake County Wednesday that it would stop working on its planned $100 million biomass plant in Lakeview"[3] (Red Rock commits funds 2013)
- Customers may not immediately switch
  - Many wait until replacing equipment
- Attractiveness of switching depends on current fuel source
  - *Oregon Public Broadcasting*, Geothermal heating system in Lakeview heats four schools and hospital[4]
  - Warner Creek Correctional Facility
    - Geothermal system with propane backup
    - 2008 Oregon SEED award

[3]October 13, 2011
[4]December 13, 2013

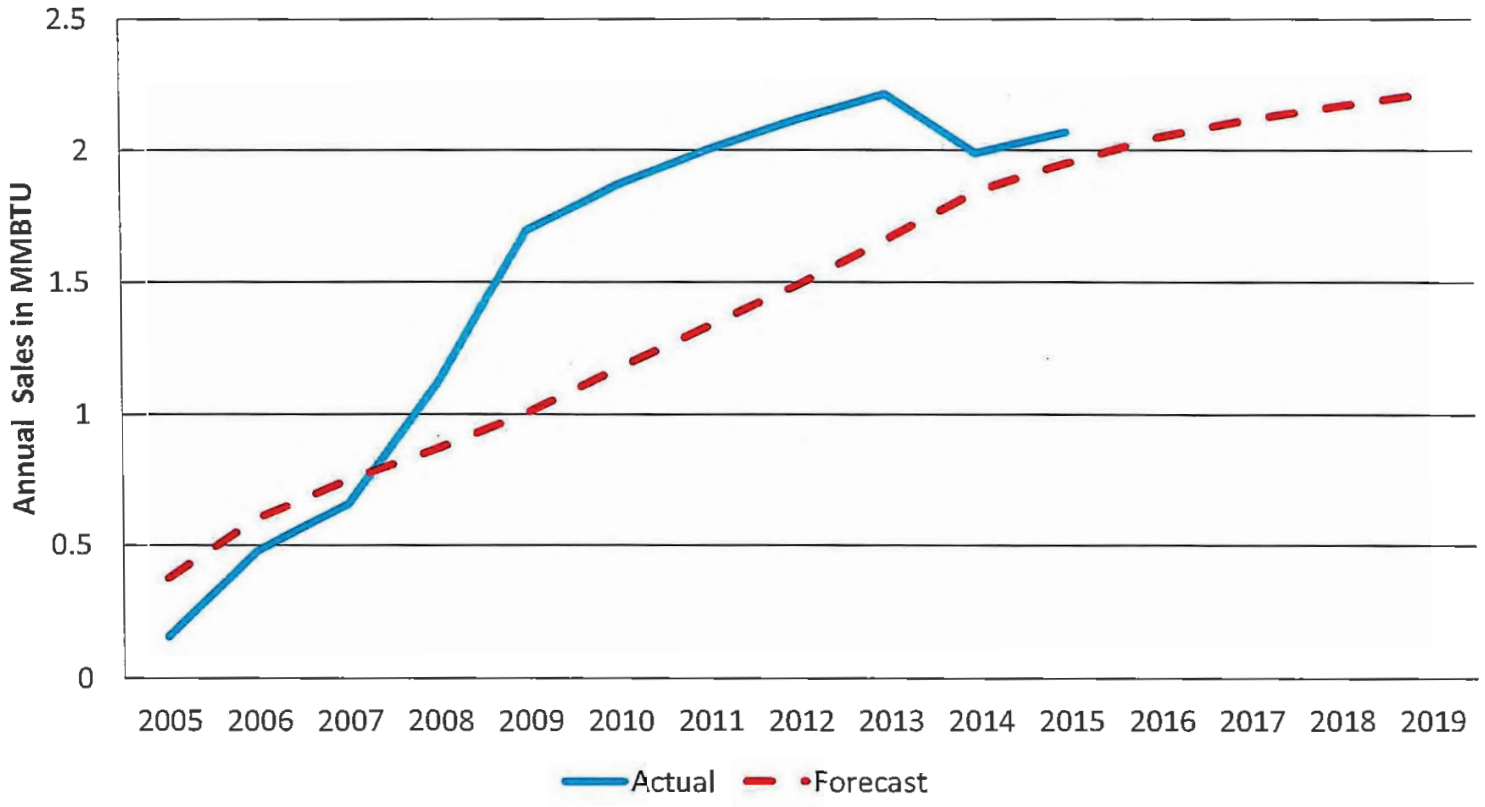
NW Natural
Coos County, OR Natural Gas Expansion

NW Natural, Coos County

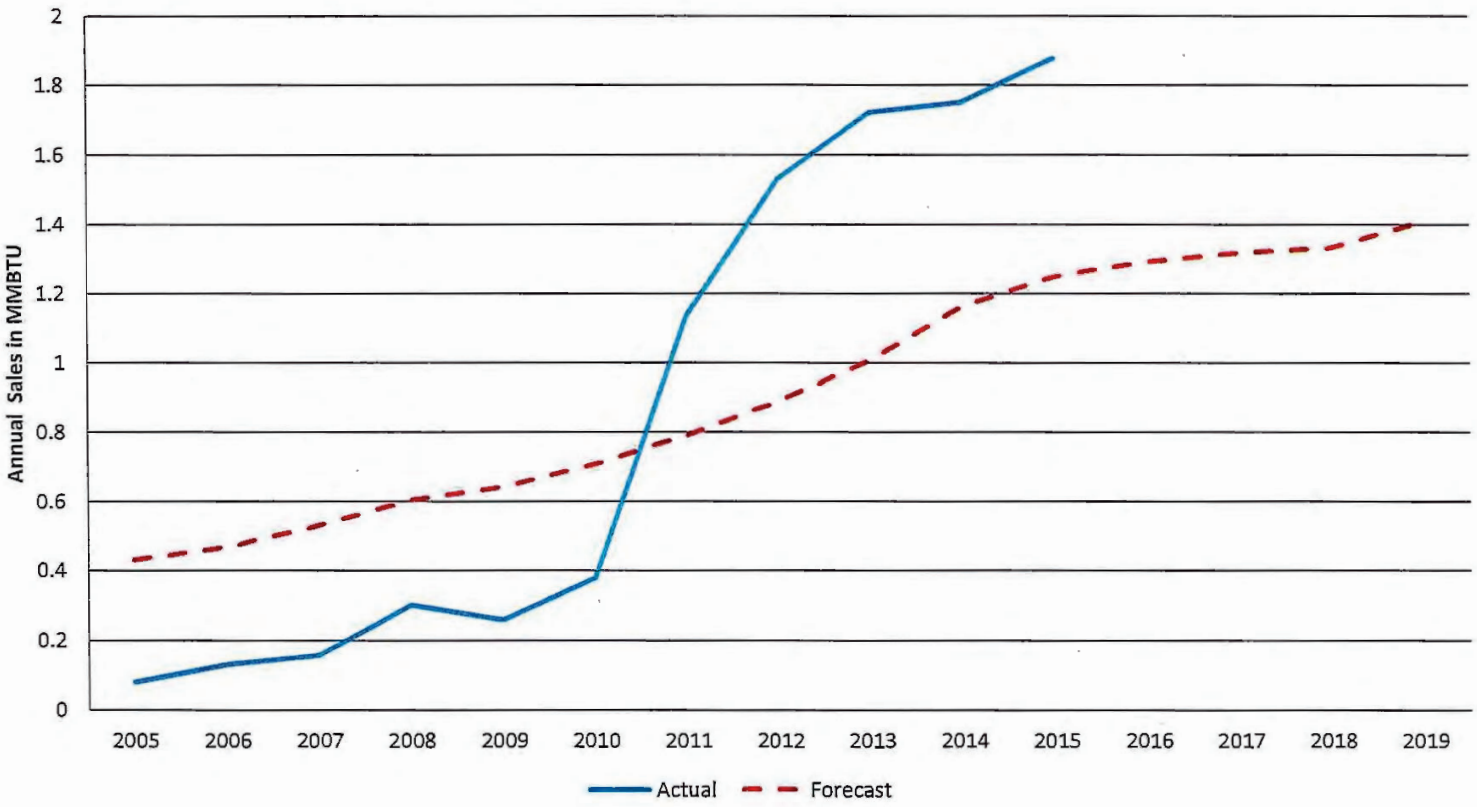


First Year Sales Forecast
94% Weyerhaeuser

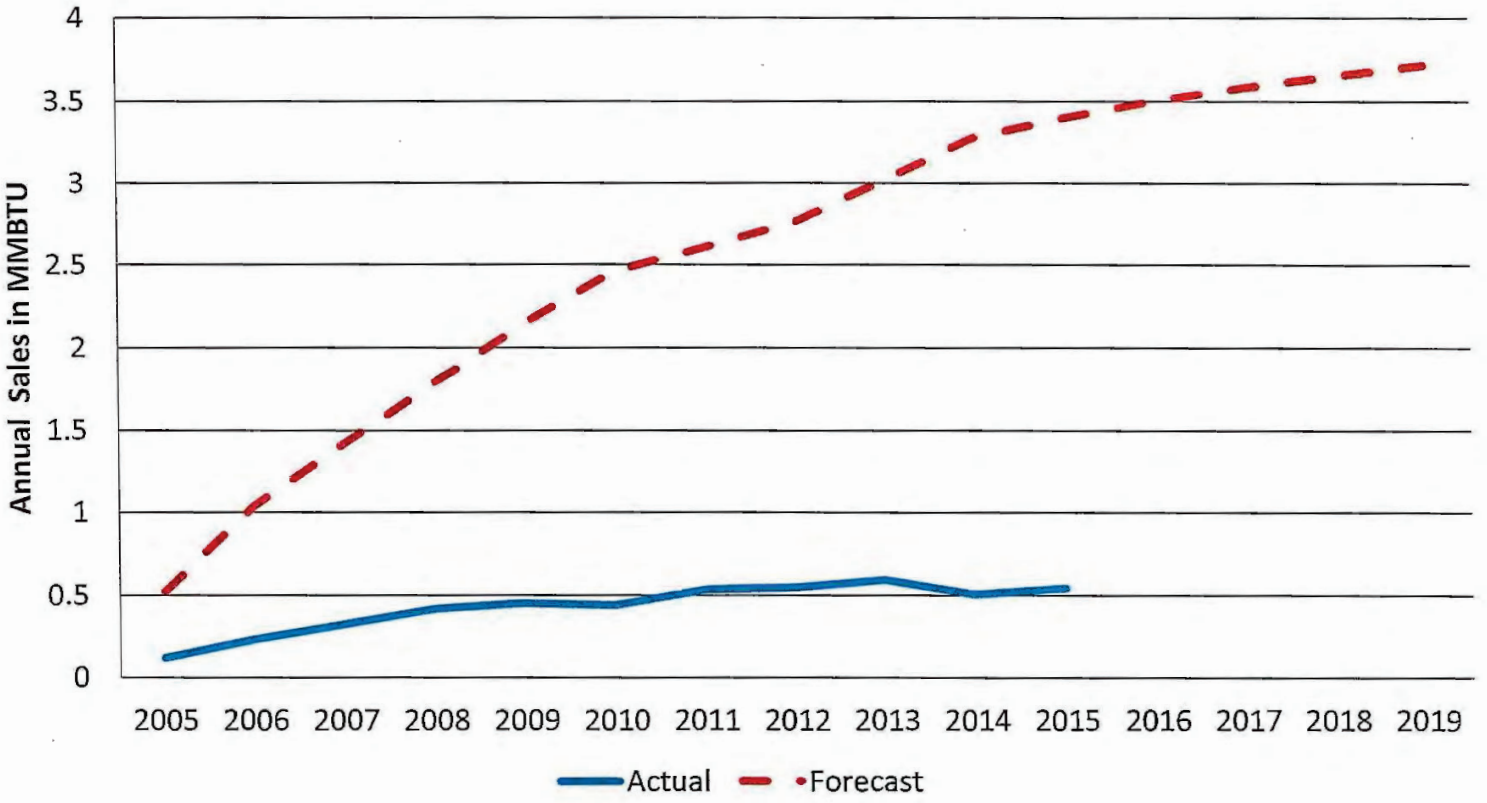
Forecast Variance for Commercial Therms



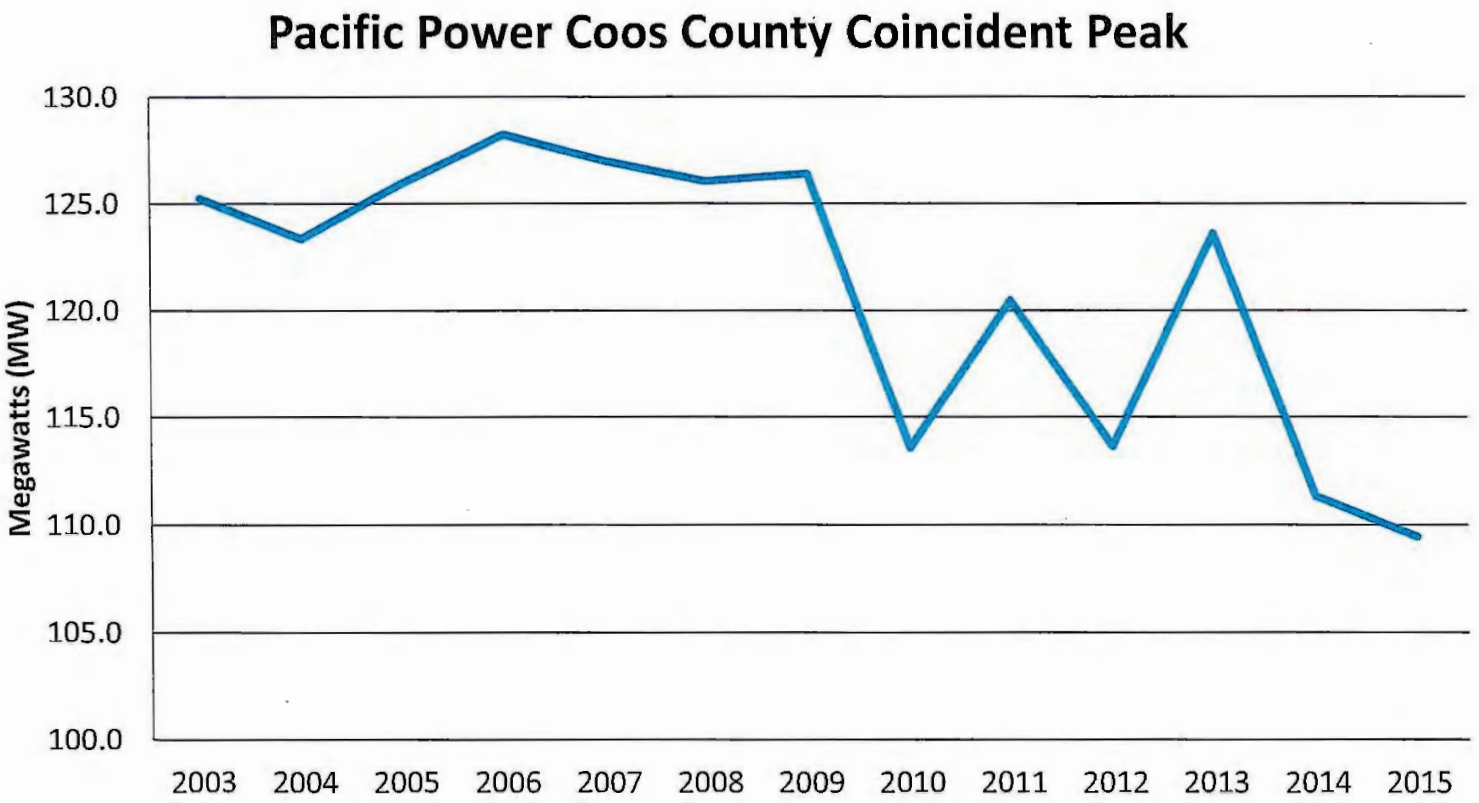
Forecast Variance for Small Industrial Therms



Forecast Variance for Residential Therms



Four Month Coincident Peak



New Distribution is Expensive

- Present Value Of Subsidy: $111 Million
  - Initial Distribution Investment $30 Million
  - Initial Pipeline Investment $78 Million
  - Ongoing Transport Cost Subsidy $3 Million
- Identified Annual Benefit: $2.4 Million

Key Takeaways

One size does **NOT** fit all

Areas unserved by natural gas can have very different profiles that include but are not limited to:

- Population (overall adoption potential).
- Interest in becoming a natural gas customer.
- Proximity to interstate pipeline.
- Local economy.
- Housing stock.
- Existing customer base to help subsidize expansion.

These potential variances impact the economic feasibility of each unserved area when calculating the financial viability of an expansion project.

Without large incentives or subsidies behind the customer meter, natural gas uptake will be slow.

Natural gas conversion can be very expensive for potential customers with regard to:

- Customer line extension costs beyond the allowance.
- Cost of ducting a home for natural gas heat.
- Cost of natural gas furnace.
- Cost of gas water heater.

Economic feasibility for gas expansion to unserved areas will be difficult if not impossible without bridging this gap.

Local financial commitment is important for gas expansion to unserved areas to be financially viable.

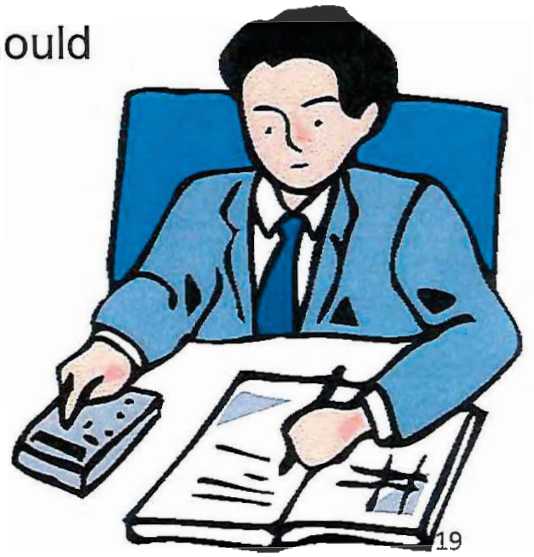
- Tax breaks for anchor customers.
- Local bond measures.
- Surcharge to new customers.
- Waive future franchise fees to offset upfront investment for expansion.
- Other local government funds.

Potential funding sources beyond those of the local government for the expansion area

- State business development funds.
- Legislative derived funds directly for the purpose of natural gas expansion.
- Air quality funds.
- State or Federal grants.
- Costs absorbed by all utility customers through rate base.
- Coordination of construction projects to reduce costs.

Thorough Financial Analysis is Critical

- New rural gas distribution is much more expensive than existing gas distribution.
- Future projects will require substantial subsidies.
- Subsidy of alternative energy sources should considered.



NPGA
NATIONAL PROPANE GAS ASSOCIATION

Introduction to the Propane Industry

Oregon Public Utility Commission
Salem, Oregon
March 31, 2016

Jeffrey M. Petrash
National Propane Gas Association
Washington, D.C.

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National Propane Gas Association

- **3000 members**
- **Producers**
- **Service providers**
- **Equipment suppliers**
- **Marketer/retailers**
  - Three large national
  - Several large regional
  - Thousands of small, local
- **38 state and regional associations**

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"THE OTHER WHITE MEAT"

- C_3H_8 (versus CH_4 for natural gas)
- Nontoxic, colorless, odorless
- 75% derived from the natural gas stream
- 25% derived from petroleum refining
- 100% percent American
- "Portable natural gas"
- Greenhouse gas emissions (GHG) similar to natural gas
- Criteria pollutants emissions similar to natural gas
- Fugitive propane is not a GHG (unlike natural gas)
- Propane not a groundwater contaminant (unlike fuel oil)
- Two percent of America's primary energy

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PROPANE AND NATURAL GAS ARE COMPLEMENTARY FUELS

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BEYOND THE BARBEQUE

Odorized propane

- Only 3% is used in barbeques
- Residential
- Commercial
- Agricultural
- Industrial
- Vehicles

Non-odorized propane

- Approximately half the market
- Petrochemical feedstock
- Exports

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USES OF ODORIZED PROPANE

- More than 5.5 million U.S. households are heated with propane
- Residential—5 billion gallons—54%
- Commercial—1.8 billion gallons—18%
- Vehicles—0.6 billion gallons—7%
- Industrial—0.5 billion gallons—5%
- Agricultural—1.1 billion gallons—12%

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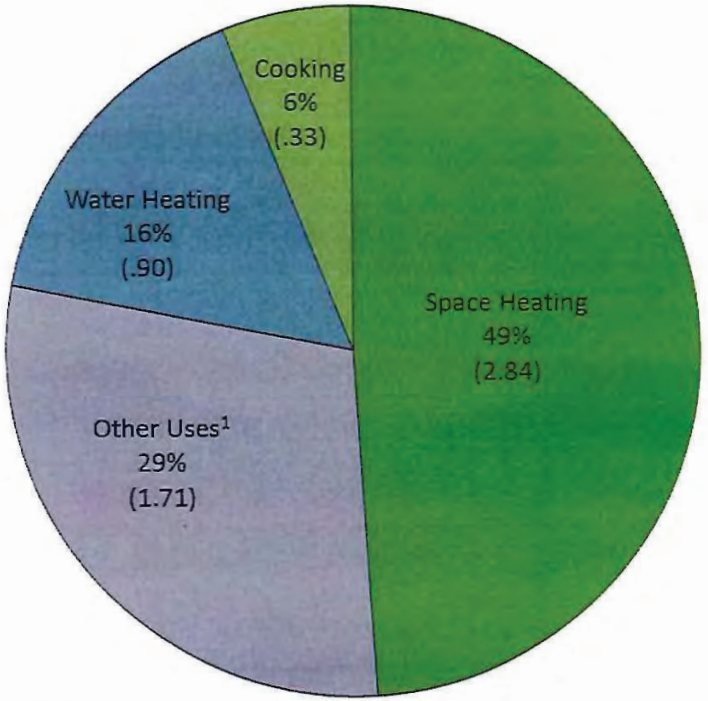
How do households use propane?

While propane is mainly used for home heating, it has many other uses as a residential heat and energy source.

Five percent of U.S. households heat with propane.

Residential Propane Consumption by End-User
(billion gallons)



[1] Other uses include clothes drying, outdoor grills, mosquito traps, etc.
Source: EIA

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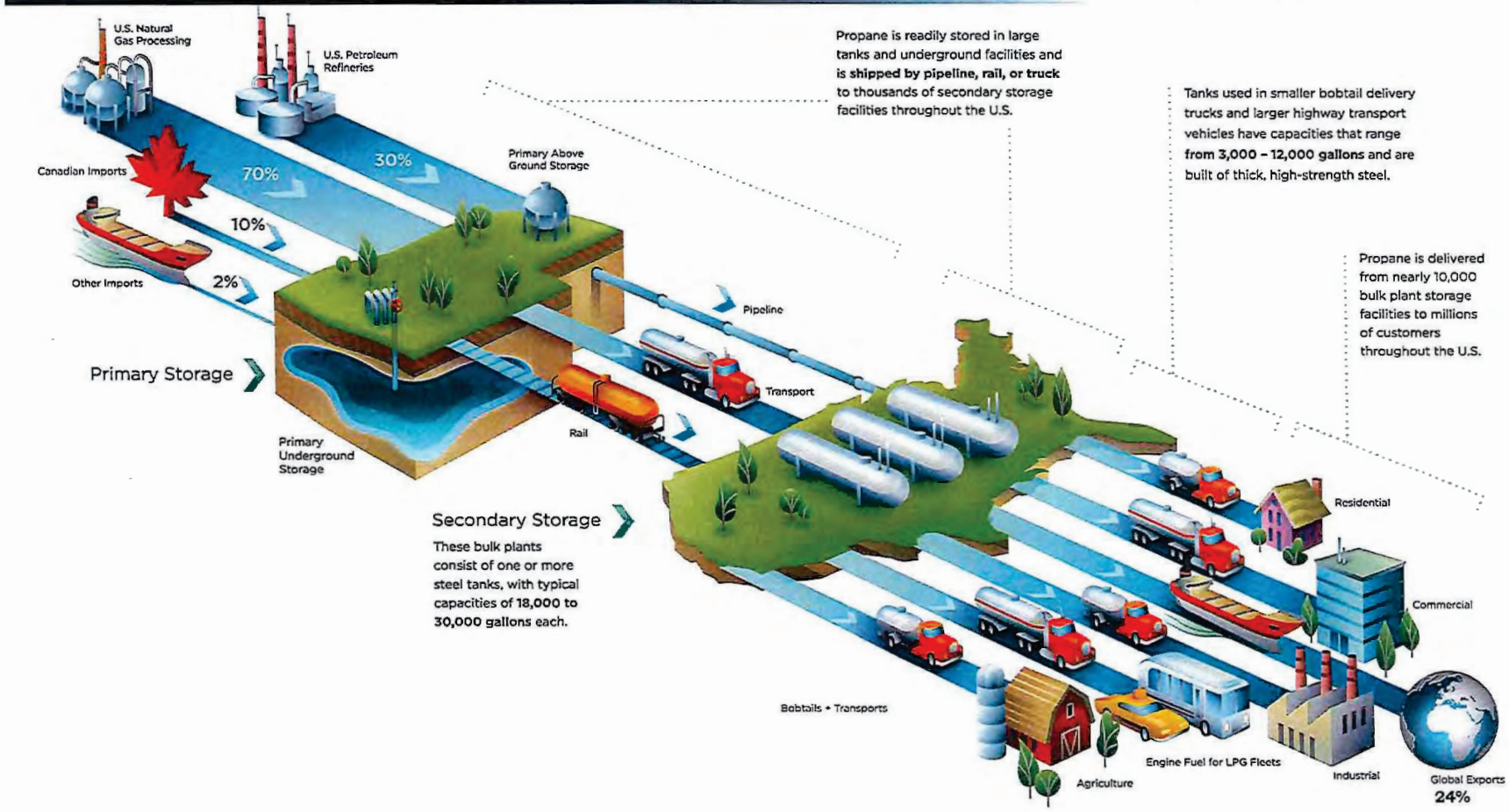

Propane is readily stored in large tanks and underground facilities and **is shipped by pipeline, rail, or truck** to thousands of secondary storage facilities throughout the U.S.

Tanks used in smaller bobtail delivery trucks and larger highway transport vehicles have capacities that range **from 3,000 – 12,000 gallons** and are built of thick, high-strength steel.

Propane is delivered from nearly 10,000 bulk plant storage facilities to millions of customers throughout the U.S.

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PROPANE IN OREGON

- Total: 63 million gallons
- Residential: 16 million gallons
- Commercial: 15 million gallons
- Cylinders: 4 million gallons
- Vehicles: 10 million gallons
- Industrial: 14 million gallons
- Agricultural: 4 million gallons
- Market value: $112 million
- Jobs: $9-10 million
- Oregon part of PADD V

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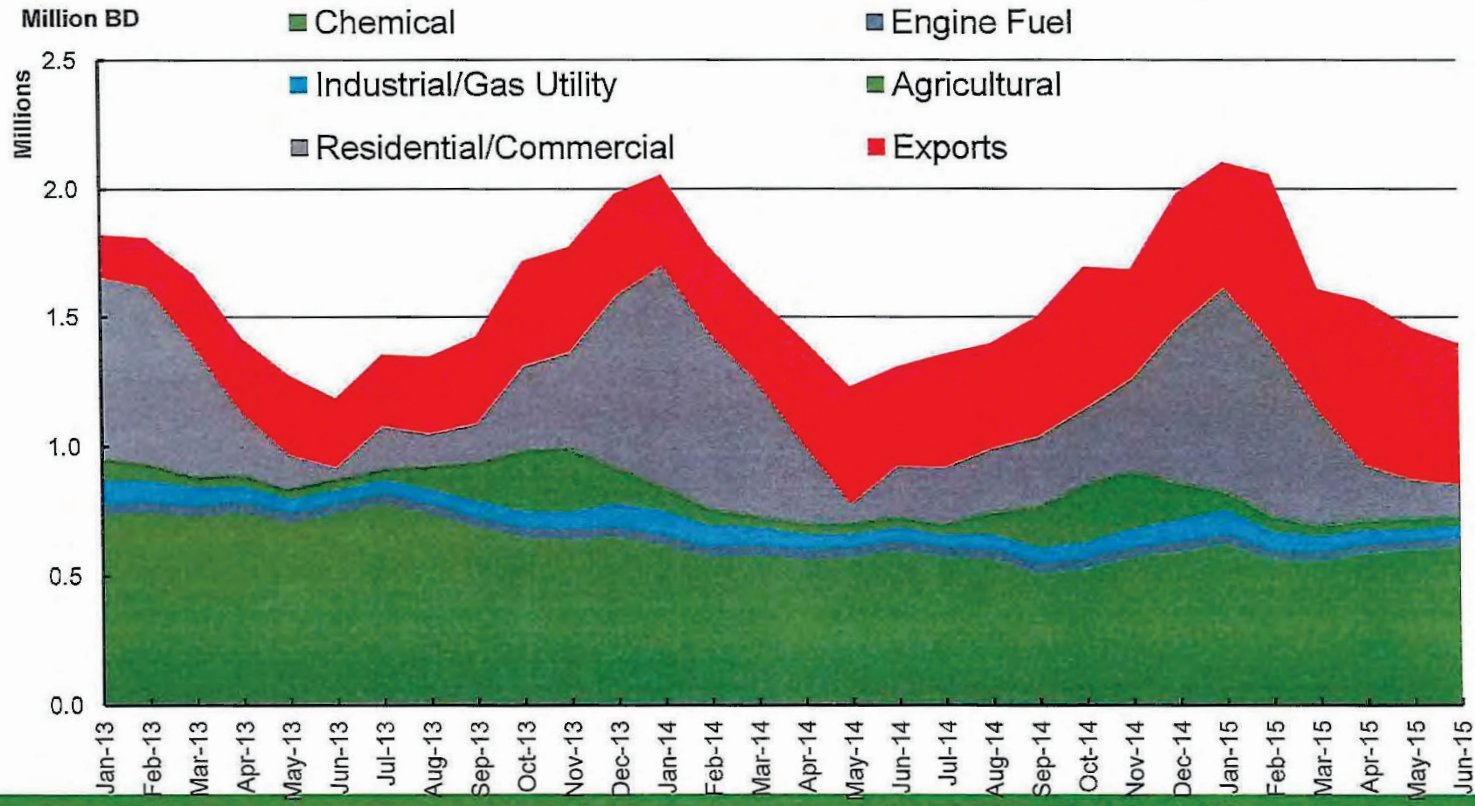
NATIONAL PROPANE GAS ASSOCIATION

KEY U.S. PROPANE DEMAND CATEGORIES



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PROPANE MARKETERS

- **Free marketers**
- **Compete with other fuels**
  - Natural gas
  - Electricity
  - Fuel oil
  - Wood
  - Ground source heat pump
- **Compete with each other**
- **Majority are small businesses**

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IT'S ALL ABOUT SHALE!

(NATURAL GAS AND PROPANE)

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LET'S CONNECT EVERYONE!

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NATURAL GAS $4

SHIPPING AND HANDLING $9

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THE REALITIES

- Facilities built today are much more expensive than facilities built in the past
- $1 million per mile is a benchmark
- Population density is necessary to make natural gas service economical
- In most circumstances rates for new service would have to be significantly higher than old service to be economic
- Conversion costs $3,500-$10,000

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SUBSIDIZED NATURAL GAS SERVICE COMPETES UNFAIRLY WITH OTHER ENERGY SOURCES

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THE ECONOMIC TEST

- Costs: building and operating the new infrastructure
- Revenues: delivery revenues for new service
- Revenues ≥ costs = economic expansion
- Revenues < costs = uneconomic expansion

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UNDERPRICED NATURAL GAS SERVICE

- ECONOMICALLY INEFFICIENT
- CAUSES MISALLOCATION OF RESOURCES
- ARTIFICIALLY CREATES DEMAND FOR THE SERVICE

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MOST EXPANSION PROPOSALS DO NOT MAKE SENSE

- **Revenues will not cover costs**
- **Utility is unwilling to deploy its capital for the expansion**
- **Utility seeks a subsidy to make the expansion**
  - Tax revenues
  - Charging existing customers (rolled-in pricing)
- **Existing customers receive no benefit or minimal benefit**
- **Why should existing customer subsidize utility shareholders**
- **Natural gas service is not a public good**

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OUR OREGON COLLEAGUES

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NATIONAL PROPANE GAS ASSOCIATION

OTHER ISSUES?

QUESTIONS?

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Gas Distribution Development in Other States

Prepared by the Oregon Public Utility Commission

At a minimum, the work group shall study:

(a) The commission's policies regarding the extension of natural gas mains;

(b) Mechanisms for funding the expansion of natural gas services, including the use of tariffs, the imposition of charges and fees, the use of unclaimed refunds and the establishment of accounts dedicated to the expansion of natural gas services;

(c) The submission of recommendations by public utilities that furnish natural gas;

(d) Possible processes for including in a public utility's rates the cost of projects involving the extension of natural gas pipelines and other infrastructure necessary for providing natural gas;

(e) Possible selection criteria for projects involving the extension of natural gas pipelines and other infrastructure necessary for providing natural gas; and

(f) The potential rate cap for projects involving the extension of natural gas pipelines and other infrastructure necessary for providing natural gas.

Minnesota

Vermont

Delaware

Indiana

Maryland

At a minimum, the work group shall study:
(b) Mechanisms for funding the expansion of natural gas services, including ... the imposition of charges and fees,

- **Minnesota**: New Area Surcharge Rider
  - Introduced in the 1990s to mitigate an adverse effect on existing customers.
  - New gas service can be brought to communities where it is not economically justified.
  - Recovers Company's revenue deficiency from customers willing to pay more to receive natural gas service.
    - The Minnesota Legislature specifically authorized such rates in Minn. Stat. § 216B.16, subd. 13, enacted in 1992[1]
    - Update enacted in 2015: up to 33% of the costs spread to all customers in Minn. Stat. § 216B.1638[2] No dockets approved, one pending[3]

WELCOME
TO
Minnesota

Minnesota New Area Surcharges

- Extensions to entire towns in remote areas
- New customers pay a share of the existing system's costs in base rates, plus incremental cost of the new extension in the surcharge, repaid over multiple years[4]

- CenterPoint Energy
  - Alexandria Lakes area
- Xcel Energy
  - Brainerd Lakes area project
  - Barnesville, Holdingford and Pillager
- Minnesota Energy Resources Corporation
  - Ely Lake

e.g. Ely Lake, Minnesota

- 2014, Commission approves monthly New Area Surcharge of **$25.45/month**, up to 20 years[5]
- The surcharge calculated in similar fashion as loan
  - Incremental cost of the new extension is principal, interest rate is rate specified in the tariff and term is length of the surcharge in years[6]
- Monthly surcharge is in addition to the regular bill for gas service.
  - Appears on bill as separate line item.

WELCOME TO
VERMONT
GREEN
MOUNTAIN
STATE

(b) … the use of unclaimed refunds and the establishment of accounts dedicated to the expansion of natural gas services;

- **Vermont**: 2011, Vermont Gas establishes the System Expansion and Reliability Fund for the purpose of facilitating further build-out of its system.
  - Substitutes for an about 5.4% rate reduction.
  - Expected to generate approximately $4.4 million annually[7]
  - Defers & escrows cost savings from quarterly Purchased Gas Adjustment (declines in the wholesale cost of natural gas)[8]
- Withdraw from The Fund for expansion

  withdrawal = cost of service – generated revenues

  associated with the expansion[9]
- e.g. 43 mile expansion into the Vergennes and Middlebury, Vermont, market areas. Commission certificate issued 2013[10]
  - $55 million estimated withdrawals.[11] Initial filing estimated costs at $87 million - updated to $154 million[12]

Welcome to
DELAWARE
SMALL WONDER
THE FIRST STATE

(d) Possible processes for <u>including in a public utility's rates</u> the cost of projects involving the extension of natural gas pipelines and other infrastructure necessary for providing natural gas;

- **Delaware:** 2012, Chesapeake Utilities proposed to recover $1.25 from all ratepayers monthly for purpose of expansion.
- Delaware's Division of the Public Advocate argued it would result in current customers subsidizing future customers[13]
- 2013, Parties settled at charging only customers within proposed expansion areas:

RS-1 Residential customer charge	ERS-1 Expansion area residential customer charge
$11.75 per month	$16.50 per month[14]

Welcome to
Indiana
Crossroads of America
Lincoln's Boyhood Home

(e) Possible selection criteria for projects involving the extension of natural gas pipelines and other infrastructure necessary for providing natural gas;

- **Indiana:** Enacted 2013, Chapter 39. Transmission, Distribution, and Storage System Improvement Charges and Deferrals (TDSIC):

  Indiana Code § 8-1-39-11 (c) allows gas utilities to extend service in rural areas without requiring a deposit if the extension of service results in a positive contribution to the utility's overall cost of service over a 20-year period.

- e.g. So far, Lizton Indiana (population <2,000) ruled to qualify, several unincorporated areas proposed[15]
- Cost cap: may not increase utility's total retail revenues by more than 2% in a year (exception: projects with Indiana economic development corporation)[16]

MARYLAND
WELCOMES YOU
ENJOY YOUR VISIT!

(f) The potential rate cap for projects involving the extension of natural gas pipelines and other infrastructure necessary for providing natural gas.

- **Maryland**: February, 2016 Senate Bill 778
  - Under consideration, concerns Natural Gas Infrastructure Expansion and Reinforcement
  - Proposes to create expansion investment regulatory asset, which gas utility later incorporates into rate base[17]

... incremental eligible expansion costs added to the [expansion investments]regulatory asset for each year the gas company defers those costs may not increase by more than 0.5% of the gas company's net rate base...

Hyperlinks in order of appearance

1. (Xcel - Petition - Mar-2-2015) https://minnesotapuc.legistar.com/LegislationDetail.aspx?ID=2353311&GUID=A88875F9-1D5A-410E-B9CE-DDF7E3722FFE&Options=&Search=
2. https://www.revisor.mn.gov/laws/?id=1&doctype=Chapter&year=2015&type=1
3. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={D37BA6B5-5C24-4B4D-BA93-37ACC5B77A87}&documentTitle=20161-117194-01
4. http://www.lec.leg.mn/2014/072814WerginPresentation.pdf
5. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={3F4B3A85-F530-4071-BA8A-6053AFC9167A}&documentTitle=20163-118842-03
6. (Briefing Papers) https://minnesotapuc.legistar.com/LegislationDetail.aspx?ID=1878961&GUID=FE2DB309-8BC0-43ED-A322-B90FCE9055A5&Options=&Search=
7. http://psb.vermont.gov/sites/psb/files/docket/7970addison/Simollardes/VGS%20ANGP%20Simollardes%20PFT%20%5b12-20-12%5d.PDF
8. http://psb.vermont.gov/sites/psb/files/orders/2011/7712ORDreModifyARPandNoticePHC.pdf
9. http://psb.vermont.gov/sites/psb/files/docket/7970addison/DPS/DPS%20Kumar.pdf
10. http://psb.vermont.gov/sites/psb/files/7970%20CPG.pdf
11. http://psb.vermont.gov/sites/psb/files/docket/7970addison/Simollardes/Exhibit%20Petitioner%20EMS-2.PDF
12. http://psb.vermont.gov/sites/psb/files/Docket%207970%20Budget%20Update%2012-19-14.pdf
13. (Docket # 12-292, Order No. 8479) https://delafile.delaware.gov/Global/AdvanceSearch.aspx
14. http://www.chpkgas.com/wp-content/uploads/2012/11/DE_Tariff-Feb-24-2016.pdf
15. https://myweb.in.gov/IURC/eds/Modules/Ecms/Cases/Docketed_Cases/ViewDocument.aspx?DocID=0900b631801c83c4
16. http://www.in.gov/legislative/bills/2013/SE/SE0560.1.html
17. http://mgaleg.maryland.gov/2016RS/bills/sb/sb0778f.pdf

NPGA
NATIONAL PROPANE GAS ASSOCIATION

A Propane Primer

Propane is a naturally occurring hydrocarbon commonly found in the production stream of oil and natural gas wells. With the chemical formula C_3H_8, it is one of the least complex hydrocarbons (technically an alkane). It is closely related to methane (natural gas), which, with the chemical formula CH_4, is the least complex of the hydrocarbons. Chemically, only ethane (C_2H_6) separates natural gas and propane. More complex hydrocarbons include butane, pentane, hexane, and octane. The molecular proximity of propane to methane has important real-world consequences, as we will discuss below.

Like natural gas, propane is colorless, odorless, and tasteless. (For both products the smell that people associate with them is artificially added at the retail level.) Both are gaseous at normal temperatures and pressures. As a result, both are readily usable as fuels in a number of applications. While natural gas liquefies at -162 Centigrade, propane liquefies at -42 Centigrade. With pressure, propane becomes a liquid at somewhat higher temperatures—hence "liquefied petroleum gas" (LPG), another name for propane. An important consequence of the difference in the temperatures at which the two compounds liquefy is that propane can be stored and transported in relatively lightweight containers and with much greater ease and economy than natural gas (in either a gaseous or liquefied state). While large volumes of propane are transported by petroleum products pipelines, it is also commercially feasible to transport it by rail, truck, ship, and barge. Technically those modes are possible for natural gas, but they are not generally economically feasible—on a retail basis—because natural gas, whether compressed or liquefied, requires much heavier storage containers and higher pressure or lower temperature. At ordinary temperatures and pressures natural gas is lighter than air, while propane is heavier than air.

Propane is produced (as with other more complex hydrocarbons) through two processes. First, it can be extracted from natural gas streams in natural gas processing plants. Second, it can be produced by refiners as part of the crude oil cracking process. Today the former method of production accounts for more than seventy percent of domestic supply. North American supplies of propane are adequate to meet the entire U.S. demand. Unlike customers of gasoline, diesel fuel, and heating oil, propane customers are not dependent upon supplies from foreign nations. (Although some propane is imported, the volume is dramatically less than the volume of exports.) Propane is in essence a byproduct, and, from a commercial perspective, production varies not so much with the demand for propane as the demand for the products of which it is a byproduct (natural gas and refinery products).

NPGA
NATIONAL PROPANE GAS ASSOCIATION

The nation is in the midst of a boom in natural gas production, largely involving the production of natural gas from shale formations. Because natural gas liquids draw higher prices in the market than natural gas on a British thermal unit (Btu) basis, producers are aggressively seeking shale gas that is rich in hydrocarbon liquids. As a result, domestic supplies of propane will be plentiful for the indefinite future.

Propane has applications in residential and commercial markets for heating (furnaces, boilers, and gas logs), water heating, cooking, and clothes drying. It is well known across America, even among those who do not use it as a primary home fuel, as a fuel source for barbecues, outdoor stoves, heaters, and the like. About fourteen million American families use propane for these various applications. Approximately six million households heat with propane. Similarly, propane has wide usage as a cooking fuel in recreational vehicles and boats. Additionally, propane commands a significant market as a transportation fuel, for forklifts, buses, vans, trucks, and cars. Indeed, there are more propane vehicles on the road than either electric or natural gas vehicles. Propane is also used as a fuel in the industrial sector both for space heating and process applications. Propane is used on nearly one million farms for irrigation pumps, grain dryers, standby generators, and other farm equipment.

Propane is a low-carbon fuel. At the point of combustion it produces 62 kg of CO_2/MMBtu, compared to 53 kg for natural gas, 71 kg for gasoline, and 93 kg for bituminous coal. Factoring in upstream emissions, propane produces 74 kg of CO_2/MMBtu, compared to 65 kg for natural gas, 91 kg for gasoline, and 221 kg for electricity. (The large number for electricity reflects the significant thermal loss in generation and the thermal loss in transmission and distribution.) A key fact in regard to carbon emissions is that when propane is released (*i.e.*, fugitive) into the atmosphere, it has essentially no greenhouse gas (GHG) effect because it deteriorates rapidly. In contrast, natural gas released into the atmosphere is approximately 25 times more potent than CO_2 as a GHG.

Propane accounts for approximately two percent of the primary energy consumed in the United States, compared to 29 percent for natural gas, 28 percent for coal, and 41 percent for petroleum products. Yet propane accounts for only one percent of the nation's GHG emissions.

Propane is essentially "portable natural gas." Most propane today is produced alongside natural gas. It is used in the same applications as natural gas. Propane has an emissions profile similar to natural gas but with the added benefit of not being a GHG itself. Propane has the important benefit of being easily transportable to areas where there is no natural gas infrastructure.

Appendix E: Line Extension Economics

September 15, 2016

Senate Bill 32
Study of Natural Gas Expansion to
Unserved Areas
2016 Report to the Legislative Assembly

Summary of Estacada Economics

Cost to build based on NWN Engineering estimates	7,563,847	
Revenue allowance based on OPUC tariff	(748,627)	
Cost for NWN Local Rep in Community (3-year offset)	-	1/
State Contribution	-	
Annual Pipeline Reservation Fees	39,013	
Short on Construction Costs vs Revenue	6,854,233	

1/ NWN has not estimated representation costs, but costs could be mitigated by the proximity of the Estacada market to the greater Portland metro and NWN service area

Summary of Lakeview Economics

Cost to build based on Avista Engineering estimates	$	7,988,441
Revenue allowance based on OPUC Tariff	$	(1,132,336)
Cost for Avista Local Rep. in Community (3 year offset)	$	750,000
State Contribution	$	-
Annual Reservation fees on Ruby Pipeline	$	106,331
Short on Contruction/Costs vs Revenue	**$**	**7,712,437**

September 15, 2016

Senate Bill 32
Study of Natural Gas Expansion to
Unserved Areas
2016 Report to the Legislative Assembly

Appendix F: Work Group Member Comments

September 15, 2016

Senate Bill 32
Study of Natural Gas Expansion to
Unserved Areas
2016 Report to the Legislative Assembly

Portland General Electric Company
121 SW Salmon Street • Portland, Oregon 97204
PortlandGeneral.com

June 30, 2016

Public Utility Commission of Oregon
Attn: Lisa Gorsuch
201 High Street, S.E.
P.O. Box 1088
Salem, OR 97308-1088

RE: PGE's SB 32 Work Group Recommendations

PGE appreciates this opportunity to offer comments on the draft Findings and Conclusions of the Senate Bill (SB) 32 Work Group concerning Natural Gas Expansion to Unserved Areas - 2016 Report to the Legislative Assembly. SB 32 directs the PUC to form a work group to conduct a study on methods by which a natural gas utility may expand the utility's service to areas that do not have access to natural gas. The legislation further directs the work group to review the Commission's authority and policies to authorize the expansion of natural gas services. PGE appreciates the work of Commission staff and the work group and offers the following comments in response to the draft Findings and Conclusions:

- Generally, PGE recommends the Workgroup articulate the factual bases of each finding within the discussion section of each finding.

- In the discussion for the second finding, it states:

  "A natural gas utility's expansion into unserved areas does provide service-related benefits to the utility's existing customers and the Commission can allocate costs associated with these benefits to the utility's existing ratepayers."

  - The declaration that expansion into unserved areas provides benefits to existing customers seems at odds with the Commission's review and treatment of the River District development (PGE Advice No. 97-15) in the PGE service territory. In that case, the burden rested with the company to demonstrate benefits to existing customers—it was not presumed. As I discussed at the May 5 meeting of the Work Group, the River District involved the company covering the initial costs of trenching, conduit and vaults, essentially the necessary service backbone in the NW Portland area described in our Tariff, Rule I. As customers connect to the system they each pay a per square foot charge to connect. For a standard 200 x 200 foot block, the initial fee was $33,280. After 2007, the connection fee was adjusted based on PGE's cost of capital.

At the time that the matter was pending before the Commission, PUC staff expressed the interest that existing ratepayers not be burdened by any of the costs. There was no finding or presumption that the expansion into the unserved area provides service related benefits to the utility's existing customers. The burden was clearly placed on the utility to demonstrate such benefit to existing customers in that instance.

- SB 32's finding and declaration that "access to natural gas is in the public interest" does not alter the Commission's previous treatment that a utility has the burden to demonstrate such benefits. Instead, the legislation requires the commission to study its policies related to expansion and "methods" for expansion. One of those methods is to allow the utility to make a showing that existing customers would benefit.

- PGE recommends that the discussion of this finding be amended to state that the gas utility may make a showing that the expansion provides benefits to existing customers or to change the referenced sentence to the conditional: "*If* a natural gas utility's expansion into unserved areas provides service-related benefits to the utility's existing customers, the Commission may allocate costs associated with those benefits to the utility's existing ratepayers."

- Finding #3 seems to be inconsistent with finding #2. Finding #3 describes how the Commission would determine whether expansion into unserved territory will result in benefits to existing customers. Finding #2 presumes that those benefits exist.

- The discussion in finding #4 repeats the statement that "expansion will have system benefits that accrue to all the utility's customers." PGE does not oppose the ability of a utility to attempt to make such a showing, but believes that the burden is on the utility to do so.

Thank you for the opportunity to comment. We look forward to reviewing the Draft Report.

Should you have any questions or comments regarding this filing, please contact me at (503) 464-8718. Please direct all formal correspondence and requests to the following email address pge.opuc.filings@pgn.com

Sincerely,

mark lindsay

For Karla Wenzel
Manager, Pricing and Tariffs

NORTHWEST GAS ASSOCIATION

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June 30, 2016

Ms. Lisa Gorsuch
Oregon Public Utility Commission
201 High Street SE #100
PO Box 1088
Salem, OR 97308-1088

Re: NWGA Comments on SB 32 Report to the Legislature

Dear Ms. Gorsuch,

Thank you for facilitating the meetings of the SB 32 Work Group chartered by the Legislature. As you develop the final draft of the Oregon Public Utilities Commission (PUC) report to the Legislature, the Northwest Gas Association (NWGA) offers the following comments for consideration.

In passing and signing SB 32, the Legislature and the Governor found and declared, "[T]hat having access to natural gas is in the public interest and… is necessary for the communities of this state to preserve local economies, enlarge tax bases and generate additional economic opportunities."

In order to fulfill the Legislature's expectations of the SB 32 Work Group, the final report must chart a clear path by which natural gas service will be extended to certain currently unserved areas of the state. Toward the objective of providing the Legislature with a report that responds to its intent and holds the promise of meaningful progress, the NWGA makes the following suggestions:

1) The SB 32 report should detail the specific actions the PUC intends to actively pursue in order to promote the extension of natural gas service to unserved areas of the state.

2) Recommendations for legislative action necessary to ensure that natural gas service is extended to unserved areas of the state ought to be included in the SB 32 report.

3) The Legislature would benefit from a summary in the SB 32 report of the successful efforts of other states in implementing policies to extend natural gas service to unserved areas. The report should break down the mechanisms each state is employing to good effect. We suggest the report include summaries of the Georgia STRIDE program, Mississippi's Supplemental Growth Rider and Pennsylvania's GETGAS program.

4) Most importantly, per Section 2(1)(c) of SB 32, the report to the Legislature should incorporate recommendations made by the NWGA (representing the natural gas utilities) during the work group process. The NWGA's recommendations include:

a. Modifying Line Extension Policies.
b. Allowing Natural Gas Expansion Tariff Riders.
c. Enabling Portfolio Treatment of Allowable Investments.
d. Approving Geographical Surcharges.
e. Providing for Customer Assistance.
    i. Permitting the use of surplus line extension allowances;
    ii. Authorizing fuel conversions & consideration of electric avoided costs.

The NWGA believes that a report incorporating the elements listed above will be responsive to the task set forth by the Legislature: to create a practical road map that will deliver natural gas to a number of Oregon communities currently just out of reach.

Thank you for your consideration,

DAN S. KIRSCHNER
EXECUTIVE DIRECTOR

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July 26, 2016

Ms. Lisa Gorsuch
Oregon Public Utility Commission
201 High Street SE #100
PO Box 1088
Salem, OR 97308-1088

Re: NWGA Comments on SB 32 Report to the Legislature, Final Draft – UM 1748

Dear Ms. Gorsuch,

Thank you for the opportunity to comment on the final draft of the Public Utility Commission of Oregon (OPUC) report to the Legislature regarding extending natural gas service to unserved communities in Oregon. The Northwest Gas Association (NWGA) offers the following comments for consideration.

We appreciate the time and effort that OPUC Staff, and all members of the Work Group put into this process. NWGA believes that the process provided an opportunity for meaningful conversation, and led to a greater mutual understanding of the important issues surrounding the topic of extending the natural gas system in Oregon. Although NWGA is disappointed in some aspects of the report, as described below, the process also points to positive opportunities.

To reiterate our prior comments, it is important that in passing SB 32 in 2015 the Legislature found and declared, "…that having access to natural gas is in the public interest and… is necessary for the communities of this state to preserve local economies, enlarge tax bases and generate additional economic opportunities." These findings and declaration provide a clear legislative emphasis on creating solutions to get natural gas to currently unserved communities.

NWGA's general takeaway from the Work Group process is that the OPUC Staff and customer representatives feel that, although the OPUC has some role to play in this regard, its role is limited and it may lack the authorities necessary to ensure that this system expansion happens. If that is accurate, we believe that the report should more clearly articulate this conclusion, given that it was the legislative genesis for requesting this report.

The NWGA's primary objective throughout this process has been to provide input and recommendations that would help the PUC be responsive to the Legislature's request by charting a clear path by which natural gas service could be extended to unserved communities that desperately need and want it. For instance, we submitted a proposal identifying a number of levers that would help facilitate service extensions including:

1) Modifying Line Extension Policies.
2) Allowing Natural Gas Expansion Tariff Riders.
3) Enabling Portfolio Treatment of Allowable Investments.
4) Approving Geographical Surcharges.
5) Providing for Customer Assistance.
    a. Permitting the use of surplus line extension allowances;
    b. Authorizing the use of electric energy efficiency incentives for fuel conversions.

The NWGA also offered the following suggestions to strengthen the PUC's initial draft report:

1) Incorporate recommendations of natural gas utilities per Section 2(1)(c) of SB 32;
2) Summarize successful efforts of other states.
3) Detail specific actions the PUC intends to actively pursue relative to extending service;
4) Include specific recommendations for legislative action to authorize new tools.

Although the final draft of the PUC's report includes these recommendations, it neither analyzes the NWGA's specific proposals, nor makes any recommendation or otherwise offers guidance to the Legislature or the utilities concerning how practically to extend natural gas service to Oregon's unserved communities. We believe the report could be improved by noting the following items:

1) There appeared to be a broad consensus that the OPUC should consider allowing utilities to modify their line extension policies to better take into consideration the longevity of customers on the gas system. This could help facilitate line extensions that both allow expansion of the system, and appropriately protect current customers.

2) The Work Group discussed that legislative action may be required to accomplish some of the recommendations offered by NWGA and its members, and that a broad effort among state agencies and other contributors may be a necessary part of accomplishing the stated goals of SB 32.

Finally, although we recognize that there was not unanimity among the work group, NWGA would like to note that we believe the OPUC may be able to take further steps to implement our recommended approaches within its existing authorities than is currently outlined in the report. We look forward to continued work on these topics to determine if some of these approaches can be implemented through discussions with the OPUC Staff and other stakeholders in the future.

Having commented on the substance of the PUC's final draft report to the Legislature, the NWGA respectfully offers a few edits for clarity and/or to correct mischaracterizations:

1) On page 6, the narrative states: "Today, more than 95 percent of the residents of Oregon's incorporated areas have access to natural gas." NWGA believes it would be appropriate to identify what the source for this statement is, as that was not discussed at the Work Group.
2) On page 6: "Two key factors ~~affect~~ correlate highly with an incorporated area's access to natural gas service. The first is population size."
3) On page 9, a number of edits which more accurately portray the principles in question:

   Subject to the Commission's review, Oregon's natural gas utilities ~~decide~~ make decisions about whether or not to extend service into unserved areas. The utilities also establish ~~their own~~ line extension policies, which the Commission reviews and approves to help ensure that the rates paid by all ratepayers are fair, just , and reasonable.

   The Commission and the utilities ~~does~~ do not require ~~a~~ new customers to pay all the costs associated with a line extension up front. Rather, ~~the Commission seeks to equitably divide these costs between new and existing customers based on the benefit that the line extension will provide to the utility system, including increased revenue generated by new customers~~line extension policies allow the utility to invest some amount without a direct charge to the customer (usually referred to as a construction allowance), in light of the increased revenue the

new customer will generate through the rates they will pay in the future. The new customer pays for expected costs above the construction allowance through a direct charge (usually referred to as a contribution). Line extension policies are generally designed to ensure that new customers pay the construction and other costs associated with securing natural gas service, either through an up-front contribution or through their rates over time.

~~The amount of line extension costs recouped through the rates of existing customers is called a "construction allowance." The construction allowance is a cap on how much of the costs of a line extension is covered by all ratepayers. Any costs above the construction allowance must be paid by the new customers through a surcharge or through other funds secured by the utility or others to fund the expansion.~~

Subject to review and approval by the Commission, each utility sets its own formula for calculating the construction allowance. Each utility currently calculates this allowance differently. NW Natural's construction allowance for new residential customers is ~~three~~ five times the annual average ~~revenue~~ margin expected from a new customer. Avista 's construction allowance for new residential customers is "three (3) times the estimated gross revenue as determined by the Company to be derived from bonafide applicants for such service[.]"Cascade's construction allowance for new residential customers is 4.5 times the estimated gross margin (gross revenue less cost of gas) to be derived from the new customer.

At any time, each utility can file a tariff to change its construction allowance formula. The utility must justify the change and show that the formula results in fair and reasonable rates for all ratepayers.

4) On page 11, under Estacada: "In ~~2015~~2005, Northwest Natural…"

5) On page 15, first bullet: "The natural gas utilities ~~argue~~ stated that the current construction allowance formulas likely fail to ~~capture all system benefits that accrue to existing ratepayers over the life of extension projects~~account for the longevity of new customers on the system. The utilities recommend that other construction allowance methodologies - such as the Perpetual Net Present Value Methodology - should be ~~used~~ considered to calculate ~~the share of project costs paid by existing customers~~construction allowances."

6) On page 15, third bullet: "…unused line extension allowances from successful line extensions ~~should~~ could effectively be banked…"

7) On page 15, fourth bullet: "Utility filings for rate recovery ~~should~~ could include targeted surcharges, as necessary, to cover shortfalls in project funding."

8) On page 16, first bullet (continued from previous page): "Use ratepayer funds to assist conversions to natural gas for specific end-uses. The gas utilities recommend that the funds dedicated for energy efficiency incentives or tied to unused line extension allowances ~~should~~ be used to help cover the cost of ~~conversions to natural gas space heat and water heating from other sources of energy~~converting from electric space and water heating to natural gas, where these conversions result in cost effective energy efficiency savings~~;~~"."

9) On page 17: " The SB 32 Workgroup ~~adopted~~ had a robust discussion on a variety topics. At a very high level, there was general agreement on the following findings and conclusions:"

10) On page 17, under Finding 2 Discussion: "Construction allowances may not reflect the full ~~benefits to ratepayers of service extensions~~amount that can be invested in extending service to new customers, while holding existing customers neutral over time. Line extensions may be evaluated over too short a time period and other benefits may not be captured in construction allowance formulas."

11) On page 18, Finding 3: *"Customers located within the area that is served after expansion will receive different benefits from expansion (access to new service) than customers outside the newly-served area (access to existing service), and both sets of customers may be charged accordingly."* (these changes attempt to specify the differences which are mostly a matter of order, timing, etc.)

In conclusion, NWGA appreciates the efforts put into the Work Group by all involved. We view it as unfortunate, however, that the final draft of the PUC's SB 32 Report to the Legislature does not provide substantive recommendations that the Commission or the utilities can undertake to extend natural gas to unserved and underserved areas as directed by the legislature.

We think the report could be improved by noting there was a broad openness to modifying utilities' line extension policies, but do not believe that this will be sufficient to accomplish the legislative goals expressed in SB 32. The report should also make the apparent conclusions about the limited role the OPUC believes it can play in expanding the natural gas system more clear. In our view, doing so will help provide the legislature more clarity about the context that seems to underlie the approach taken in the OPUC's report.

Thank you for your consideration,

DAN S. KIRSCHNER
Executive Director

Senator Whitsett
SB 32 Comments
July 12, 2016

1.) Senate Bill 32 states in part that the Legislative Assembly "*finds and declares that having access to natural gas is in the public interest and that the extension of natural gas pipelines and other infrastructure necessary for providing natural gas to areas that do not have access to natural gas is necessary for the communities of this state to preserve local economies, enlarge tax bases an generate additional economic opportunities,*" That statement would appear to direct OPUC to determine and delineate pathways for natural gas service expansion both under existing statutory authority and under OPUC recommended amendments to existing law. The draft report appears to do neither.

2.) To my knowledge, Avista has not abandoned their efforts to extend natural gas service to Lakeview. They appear to be remain actively engaged in that effort.

3.) What other history of natural gas expansion to underserved or unserved areas has occurred in Oregon. For instance, how and when did 21 of 43 small towns located within 15 miles of a natural gas pipeline acquire natural gas service? How and when did 15 of 32 small towns located within approximately 10 miles of a natural gas pipeline acquire natural gas service?

4.) Why has OPUC not addressed questions regarding the existing expansion of natural gas service to Shady Cove? Under what authority and economic reasoning was that expansion authorized by the Commission? Will Commission staff provide an Appendix E type table for the Avista Shady Cove expansion project?

5.) Regarding alternative funding sources, why would only "new" revenue from the investor owned natural gas utilities public purpose charge be considered? Does OPUC have statutory prohibitions or Commission objection by rule that would prevent existing public purpose charge moneys collected from investor owned natural gas utility customers to be expended toward expansion of natural gas services to unserved or underserved areas?

6.) The text of the draft report suggests that investor owned natural gas utilities are authorized to file for a change in tariff pretty much at will. However, it is my understanding that OPUC must approve such an application. What history can OPUC describe of utilities applying for such tariff changes? What has been the Commission's history of approval or denial of such tariff change requests?

Response To

SB 32, 2016 OPUC Draft Report to Legislative Assembly

Ken Kestner, Lake County Commissioner

26 July 2016

1. I'll reiterate the points made by Senator Doug Whitsett.

2. I'll emphasize the strategy of collaborative/coordinated & bundling multi-funding scenario, as local, multiple state agencies/depts., LDCs, etc.
   On the State's behalf, as others have emphasized, I encourage the 'transparency', which should apply to all other state-funded endeavors.

3. Likewise, I emphasize in the 'construction allowance' that multi-benefits AND long-term benefits be considered.
   I recognize that PERPETUITY means 'forever' and the objection by some providers, so therein I stress emphasis on a reasonable LONG-TERM approach, which might encompass several decades. *(I understand that "Reasonable" is interpreted differently by different people; that's where Legislative Assembly can embody an interpretation.)*

4. LDCs' recommendation of OPUC adopting the legislative policy statement in SB 32 is noteworthy.
   Having such policy embodied in OPUC gives a tone of emphasis to further facilitate LDCs efforts to expand Nat Gas, as facilitate changes in tariff, etc.

5. On surcharges, as reasonable new customers' surcharges, such would contribute to the local funding contribution.
   I'm a little reserved, though not fully opposed, on the Geographical Surcharges concept. A small percentage with possible long-term return to existing customers would be palatable for me.

6. On subject of 'customers' assistance', if considered, I agree such should be applicable & fair to all energy providers.

7. I do like the notion of "banked" amounts of any unused portions of line extension allowances.

KK –

NORTHWEST INDUSTRIAL GAS USERS

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Edward A. Finklea
Executive Director

E-Mail: efinklea@nwigu.org

July 26, 2016

VIA E-MAIL
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lisa.gorsuch@state.or.us

Re: SB 32 –Northwest Industrial Gas Users' Comments on Draft Report

Dear Ms. Gorsuch:

Per your request to the members of the SB 32 Workgroup, I am providing comments to you on the Draft Report to the Legislative Assembly ("Draft Report").

At the outset, I want to thank Staff for sharing this draft and for capturing the discussion that occurred during the workshops. I do not have any suggested changes to the Draft Report.

The initial sections of the Draft Report do a good job reflecting the history of the extension of natural gas service. In both the description of how line extensions work and in the case study section, the common principle is that line extensions are primarily paid for by the customers who seek the new service and that existing ratepayers contribute only to the extent that they will benefit from an expanded system. Natural gas service and electric service are often viewed as similar services simply using a different fuel, but the reality is that there are fundamental differences in these services and how they have evolved. Natural gas service has traditionally been developed as the result of customers deliberately choosing that fuel source. As such, expansions of a natural gas system have occurred only when it makes economic sense for the customer to pay for that service, including the costs of expanding a system to provide the service.

As the Coos County case study similarly demonstrates, sometimes it is a broader community that makes the economie deeision to obtain new service, in which case other public funds (i.e. bond revenue or lottery funds) may be appropriate for use to expand the system.

The specific findings included in the Draft Report also accurately capture the limits of, and opportunities for, system expansion. For example, if construction allowances do not accurately reflect all of the benefits to the existing system, there may be opportunity to revise line extension policies for that purpose. This is not anathema to the existing system, which contemplates that all customers will pay for the benefits they receive. Similarly, there may be opportunities for having surcharges to multiple customers in an expanded area as described in Finding 3. This approach of having a community pay for incremental capacity is precisely how all interstate pipeline expansions have been priced by FERC since the mid-1990s and it is reasonable to model a state system after this federal approach.

I look forward to reviewing the comments of other Workgroup members and assisting the PUC in developing the final report.

Sincerely,

/s

Edward A. Finklea

OREGON PEOPLE'S UTILITY DISTRICT ASSOCIATION

July 26, 2016

Public Utility Commission of Oregon
Attn: Lisa Gorsuch
201 High St., SE
P.O Box 1088
Salem, OR 97308-1088

Re: Joint Consumer-Owned Utility Comments on OPUC Docket 1748, Access to Natural Gas Infrastructure in Underserved Areas

Oregon's Consumer-Owned Utilities (COUs) appreciate the opportunity to comment on the OPUC draft report to the 2016 Legislature on SB 32, Access to Natural Gas Infrastructure in Underserved Areas. Our comments are focused on the mechanism for funding the expansion of natural gas service.

The draft report concludes that large amounts of funding will be necessary to cover the cost of gas service extension to underserved areas. (Draft Report, Page 18.) In a cost versus benefits analysis, Oregon's COUs do not support using Oregon General Fund dollars to provide gas service in COU territories. Oregon's COUs already deliver safe, reliable, and affordable carbon-free electricity to our customers. Oregon COU's obtain the majority of their power from the Bonneville Power Administration (BPA). We follow a regional electric power plan to guarantee adequate and reliable energy at the lowest economic and environmental cost to the Northwest. COU customers are already benefitting from at-cost power that is largely carbon-free. Spending state taxpayer dollars to extend natural gas services to areas served by consumer-owned utilities would do little, if anything, to reduce carbon emissions in our electric system or reduce global CO2 levels. In fact, extending natural gas services to these areas likely would increase CO2 emissions as customers switch from largely carbon-free electricity to natural gas.

We do not support using taxpayer or lottery revenue to fund natural gas service expansion. We have a fundamental objection to using taxpayer dollars to subsidize a private for-profit company when the customers are already being well-served by a non-profit utility providing at-cost, clean, renewable power.

We appreciate being part of this process. Thank you for the opportunity to comment.

Ted Case, ORECA Beth Vargas-Duncan, OMEU Danelle Romain, OPUDA

Jason Heuser, EWEB

PACIFIC PROPANE GAS ASSOCIATION

Representing the Propane Gas Industry for

Alaska, Hawaii, Oregon and Washington

Comments of the Pacific Propane Gas Association
On the SB 32 Work Group 2016 Draft Report to the Legislative Assembly
July 20, 2016

The Pacific Propane Gas Association (PPGA) once again appreciates the opportunity to be heard with respect to its views on the issues being considered by the Senate Bill 32 natural gas working group. PPGA particularly appreciates the manner in which Staff has conducted the working group sessions and has heard the varying viewpoints of the different stakeholders in the process. PPGA commends Staff for its even-handed presentation of these views in the draft report.

PPGA endorses the reading given to Senate Bill 32 by Staff. The legislature has certainly recognized the benefits of natural gas as a fuel and has required the Oregon Public Utility Commission to convene a work group to solicit input from stakeholders and to explore means by which natural gas service might be made available to more consumers. The end result of this process is a report to the Legislature, not a plan to expand natural gas service to all citizens of Oregon. As Staff appears to have concluded, the reading of the statute championed by the natural gas utilities includes an element that is simply not there.

PPGA appreciates the recognition by Staff of its views on these issues. The types of expansions of natural gas service in Oregon that were addressed by the working group all appear to be uneconomic—delivery revenues for the service will not cover the costs of providing the service. Indeed, were the delivery revenues sufficient to cover the cost of service these expansions would already have occurred, as Northwest Natural, Avista, and Cascade presently have the means to undertake them, with no necessary change in policy or law. And there is no doubt that they have ready access to capital markets to fund such expansions. As the draft report points out, 95 percent of Oregonians in incorporated areas already have access to natural gas service.

As PPGA has expressed previously, natural gas expansions that are not economic run counter to sound public policy if they are subsidized by either taxpayers or existing captive natural gas customers. Utility shareholders, who have decided not to deploy their own capital, should not be subsidized by either taxpayers or captive utility customers. On the other hand if utility shareholders do desire to put their capital at risk in financing an expansion, then PPGA would have no objection. Subsidized natural gas expansion is wrong for many reasons, including:

- It violates the fundamental utility regulatory principle that costs should be allocated to those who cause them to be incurred
- It underprices the service to those who receive it, resulting in an inflated demand for the service
- By underpricing the service and inflating the demand, it causes an inefficient allocation of resources

- Natural gas service is not a public good such as parks and highways, where the costs involved are shared among all citizens
- Even if natural gas service were a public good, citizens would benefit more from funding any number of more worthy ventures
- It is unfair to the captive customers who are compelled to subsidize new customers and utility shareholders and who receive little, if any, benefit from the expansion
- It unfairly, and without justification, tilts the competitive playing field against competing energy sources such as electricity, propane, fuel oil, and wood.

PPGA recognizes that natural gas expansion can benefit existing natural gas customers. This is, however, an inherently fact-specific analysis, of the type for which utility regulators have great experience. Broad generalizations have no place in assigning expansion costs to existing customers. Clearly there will be instances in which existing customers receive benefits in terms of system reliability, but these will be fact specific. In contrast, benefits associated only with increased throughput (for example, spreading general and administrative costs over more units of throughput) will usually be so modest as to be difficult to measure. Additionally, benefits for existing natural gas customers are to be found in the numbers in the utility's books—not hypothetical and unverifiable economic development and environmental "benefits".

At the heart of this inquiry is the cold fact that expanding a natural gas network is an exceedingly expensive venture, with system costs hovering around $1 million per mile. As the report points out, two factors are determinative—population and distance to a natural gas distribution or transmission line. The result is that high population density near natural gas lines leads to affordable expansion; low population density remote from a natural gas line leads to unaffordable expansion. Most of Oregon that is unserved falls in the latter category; it is the unavoidable fact. Natural gas service to these communities will simply not be possible without significant wealth transfers. Neither the Oregon Public Utility Commission nor the Legislature have it within their powers to change these facts. As the report concludes, the cost of natural gas expansion is a major impediment.

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February 2, 2026, Regular Public Meeting of the Oregon Public Utility Commissioner

Audio Transcription

1

00:00:02.830 --> 00:00:15.170

Chair Letha Tawney - Oregon PUC: Good morning! Today is, February 3rd, 2026, and this is a regular public meeting of the Public Utility Commission of Oregon, and all commissioners are present this morning.

2

00:00:16.010 --> 00:00:24.909

Chair Letha Tawney - Oregon PUC: We take time at the beginning of each meeting to provide the public an opportunity to comment on issues not listed on the written agenda.

3

00:00:25.030 --> 00:00:32.500

Chair Letha Tawney - Oregon PUC: And so, if anyone wishes to comment, you can use the raise your hand feature, or press star 9 if you're dialed in.

4

00:00:32.689 --> 00:00:44.629

Chair Letha Tawney - Oregon PUC: And if you, can't find either of those, you can unmute yourself and just speak up. So I'll pause and see if there's any public comment on items not on the agenda this morning.

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00:00:46.860 --> 00:00:49.989

Chair Letha Tawney - Oregon PUC: Excuse me.

6

00:00:50.510 --> 00:00:59.550

Chair Letha Tawney - Oregon PUC: Okay, I'm not seeing anyone this morning, so let's move on to the consent agenda. Do I have a motion to approve the consent agenda?

7

00:01:01.280 --> 00:01:03.499

Comm. Karin Power - Oregon PUC (she/her): I'll move to approve the consent agenda.

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00:01:03.500 --> 00:01:04.330

Comm. Les Perkins - OPUC: I'll second.

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00:01:05.000 --> 00:01:10.090

Chair Letha Tawney - Oregon PUC: I concur, and the consent agenda is adopted. Excellent.

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00:01:10.490 --> 00:01:19.130

Chair Letha Tawney - Oregon PUC: Let's move on to the regular agenda. This morning, we're starting with RA1, docket number UM1730.

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00:01:19.530 --> 00:01:24.840

Chair Letha Tawney - Oregon PUC: And I believe Ryan Bain from staff is introducing this.

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00:01:25.820 --> 00:01:27.099

Chair Letha Tawney - Oregon PUC: Good morning, Ryan.

13

00:01:27.510 --> 00:01:28.630

Ryan Bain - OPUC: Good morning.

14

00:01:29.060 --> 00:01:33.030

Ryan Bain - OPUC: Good morning, Chair Taney, Commissioner Perkins, and Commissioner Power.

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00:01:33.270 --> 00:01:43.049

Ryan Bain - OPUC: For the record, my name is Ryan Bain. I'm an analyst in the OPUC. I'm joined today by Staff Manager Curtis Deloie and Staff Council Stephanie Andrews.

16

00:01:43.420 --> 00:01:57.919

Ryan Bain - OPUC: On January 8th, Idaho Power Company filed its required post-IRP acknowledgement avoided cost update. I'm here today to recommend suspension of the company's update to its standard avoided cost schedule for further investigation.

17

00:01:58.050 --> 00:02:07.170

Ryan Bain - OPUC: Due to staff's need for additional time to complete its review, and to incorporate stakeholder input under the 30-day period granted by statute.

18

00:02:07.660 --> 00:02:15.160

Ryan Bain - OPUC: The company's post-RP acknowledgement of what a cost update includes updates to the sufficiency period.

19

00:02:15.310 --> 00:02:34.179

Ryan Bain - OPUC: Forward on and off peak, electric market prices, natural gas prices, capacity contribution values, updates to solar and wind integration charges based on the company's 2025 variable energy resource integration study, and updates to the on and off-peak hour definitions.

20

00:02:34.450 --> 00:02:42.709

Ryan Bain - OPUC: During its review, staff issued an information request for the company's 2025 EER integration study with a due date of January 30th.

21

00:02:42.930 --> 00:02:48.560

Ryan Bain - OPUC: This necessitated suspension of the filing to ensure time for adequate review.

22

00:02:48.790 --> 00:03:03.609

Ryan Bain - OPUC: Additionally, through communication with stakeholders, staff learned that there is desire amongst QF parties to file comments regarding this avoided cost update, and desire in kind from the company to share comment and response as warranted.

23

00:03:03.870 --> 00:03:18.500

Ryan Bain - OPUC: Staff will use the additional time it has requested to ensure parties have adequate time to file comments and a response, and for staff to incorporate those comments into its memo, and the goal of ensuring that avoided costs reflect the appropriate values.

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00:03:18.710 --> 00:03:31.579

Ryan Bain - OPUC: Staff now anticipates bringing this filing before the Commission at the March 17th public meeting, and will be posting a comment deadline to parties likely to be the 13th of February, should the filing be suspended.

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00:03:32.040 --> 00:03:41.789

Ryan Bain - OPUC: So to summarize, staff recommends that the Commission suspend Idaho Power Company's post-RP acknowledgement update to its standard avoided cost schedule for further investigation.

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00:03:41.950 --> 00:03:44.210

Ryan Bain - OPUC: And I'm available to answer any questions.

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00:03:45.570 --> 00:03:47.229

Chair Letha Tawney - Oregon PUC: Thank you so much, Ryan.

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00:03:47.480 --> 00:03:49.510

Chair Letha Tawney - Oregon PUC: Any questions for Ryan?

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00:03:50.760 --> 00:03:52.200

Chair Letha Tawney - Oregon PUC: Nope? Okay.

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00:03:53.000 --> 00:03:54.950

Chair Letha Tawney - Oregon PUC: Appreciate the thoroughness.

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00:03:55.190 --> 00:04:01.560

Chair Letha Tawney - Oregon PUC: Any, so let me call for public comment. Any comments?

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00:04:01.810 --> 00:04:10.540

Chair Letha Tawney - Oregon PUC: For many stakeholders on... 1730, Idaho powers. Avoided cost.

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00:04:11.550 --> 00:04:13.169

Chair Letha Tawney - Oregon PUC: You can raise your hand.

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00:04:14.890 --> 00:04:16.000

Chair Letha Tawney - Oregon PUC: Alright.

35

00:04:16.300 --> 00:04:18.139

Chair Letha Tawney - Oregon PUC: I'm not seeing any.

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00:04:18.760 --> 00:04:25.929

Chair Letha Tawney - Oregon PUC: So, let's turn to deliberation. Colleagues, perspectives on this?

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00:04:27.170 --> 00:04:31.770

Comm. Les Perkins - OPUC: Chair Taney, I would just move that we, approve the proposed commission motion.

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00:04:32.600 --> 00:04:33.599

Comm. Karin Power - Oregon PUC (she/her): And I'll second.

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00:04:34.300 --> 00:04:39.550

Chair Letha Tawney - Oregon PUC: I concur, and the motion is adopted. Excellent, we'll look forward to seeing that back.

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00:04:39.790 --> 00:04:41.240

Chair Letha Tawney - Oregon PUC: Shortly.

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00:04:41.390 --> 00:04:45.110

Chair Letha Tawney - Oregon PUC: Appreciate everyone's, work to get that done quickly.

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00:04:46.040 --> 00:04:51.690

Chair Letha Tawney - Oregon PUC: Alright, let's move on to RA2, docket UM2427.

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00:04:52.460 --> 00:04:57.449

Chair Letha Tawney - Oregon PUC: wildfire study, from the, PUC.

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00:04:57.680 --> 00:04:59.900

Chair Letha Tawney - Oregon PUC: Lara, please.

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00:05:01.490 --> 00:05:10.299

Laura Tabor, OPUC: Good morning, Chair Taney, Commissioner Perkins, and Commissioner Power. For the record, my name is Lara Tabor, and I'm the Legislative Affairs Director at the PUC.

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00:05:10.520 --> 00:05:19.950

Laura Tabor, OPUC: Today, I'm presenting staff's recommendation for the PUC to move forward with an expert study on utility wildfire liability and accountability issues.

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00:05:20.900 --> 00:05:25.329

Laura Tabor, OPUC: As you all know, there has been much policy debate on these topics recently.

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00:05:25.520 --> 00:05:37.960

Laura Tabor, OPUC: Many are concerned with the length of time that Oregonians impacted by wildfires have gone without compensation. Meanwhile, investors recognize the financial risks that utilities face in Oregon.

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00:05:38.020 --> 00:05:50.829

Laura Tabor, OPUC: due to our current legal frameworks for wildfire liability. As a result, higher borrowing costs are beginning to impact ratepayers, and power producers see heightened risk in entering contracts with our utilities.

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00:05:51.130 --> 00:05:59.480

Laura Tabor, OPUC: Consumer-owned and investor-owned utilities alike are both seeing skyrocketing insurance costs, which also fall on ratepayers.

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00:06:00.120 --> 00:06:12.670

Laura Tabor, OPUC: Identifying a better framework for Oregon will take significant research, engagement, and negotiation across the many interested parties affected by these issues. This agency cannot take all of this on.

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00:06:12.780 --> 00:06:25.759

Laura Tabor, OPUC: But, as outlined by the recent Oregon State Energy Strategy, released by the Oregon Department of Energy, we can provide valuable information from experts in this field to inform future policy discussions.

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00:06:26.030 --> 00:06:40.150

Laura Tabor, OPUC: To that end, the motion before you would direct staff to issue a request for proposals via the Department of Administrative Services, or DAS, to engage an expert consultant to develop a report on policy options

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00:06:40.160 --> 00:06:55.969

Laura Tabor, OPUC: For both investor-owned and consumer-owned utility wildfire liability risk that appropriately balance utility accountability for wildfire risk mitigation, customer needs for reliable and affordable essential services, and timely compensation for wildfire victims.

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00:06:56.470 --> 00:07:08.560

Laura Tabor, OPUC: This motion also directs PUC staff to retain control of the RFP, the vendor selection, the study scope, process, and final content, regardless of the funding source.

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00:07:09.170 --> 00:07:22.440

Laura Tabor, OPUC: The PUC's legislatively approved budget for the biennium does not include funds for this expertise necessary to complete this study. Accordingly, staff proposes that Pacific Corp and PGE fund the study.

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00:07:23.100 --> 00:07:32.990

Laura Tabor, OPUC: Staff has begun preparing for this solicitation in close coordination with DAS, and intend that the study be complete and publicly released before the end of 2026.

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00:07:33.120 --> 00:07:36.909

Laura Tabor, OPUC: This concludes my presentation, and I am happy to take any questions.

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00:07:37.980 --> 00:07:43.740

Chair Letha Tawney - Oregon PUC: Thank you so much, Laura. Questions, colleagues, for Lara on the study?

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00:07:45.370 --> 00:07:49.449

Chair Letha Tawney - Oregon PUC: The memo was... was quite clear, so thank you.

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00:07:51.110 --> 00:07:57.639

Chair Letha Tawney - Oregon PUC: Alright, I'll ask for a raise of hands from folks who might want to comment on this.

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00:07:57.770 --> 00:08:02.299

Chair Letha Tawney - Oregon PUC: And I want to start with, Representative Marsh.

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00:08:02.940 --> 00:08:04.810

Chair Letha Tawney - Oregon PUC: Thanks for joining us this morning.

64

00:08:06.190 --> 00:08:16.949

Pam Marsh: Good morning, Chair Taney and members of the Commission. Thank you so much for the opportunity to offer brief comments. I'm Pam Marsh, State Representative from District 5, which is Southern Jackson County.

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00:08:17.220 --> 00:08:26.899

Pam Marsh: I am here this morning to strongly urge the Commission to adopt the staff recommendations and move forward with the proposed RFP for a wildfire study.

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00:08:26.980 --> 00:08:37.869

Pam Marsh: I have been aware of, and frankly, quite worried about, the risk that our wildfire-prone world poses for the state's small and large utilities for a long time.

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00:08:37.870 --> 00:08:49.469

Pam Marsh: In 2020, my own district experienced a disastrous wildfire, cause unknown, and we know well how vulnerable our landscapes are to these times of drought and increasing temperatures.

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00:08:49.560 --> 00:08:58.179

Pam Marsh: For utilities with high-risk infrastructure, the threat of wildfire in these conditions is nothing less than an existential crisis.

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00:08:58.500 --> 00:09:12.180

Pam Marsh: Our utilities are doing everything possible to corral risk, including wildfire mitigation and safety investments. But all the safety investments in the world can't eliminate risk. And those investments are increasingly expensive.

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00:09:12.500 --> 00:09:27.390

Pam Marsh: That's an issue, since ratepayers are on the hook for those costs. Wildfire mitigation often comes at the expense of reliability and undermines the utility's ability to make critical investments to expand energy supply or to build transmission.

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00:09:27.740 --> 00:09:35.079

Pam Marsh: Uncorralled wildfire liability risk increases the cost of capital and will threaten the solvency of the utility.

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00:09:35.440 --> 00:09:44.949

Pam Marsh: And when things go terribly wrong, despite best efforts, Oregonians who are impacted by wildfire, whatever the cause, need support for their recovery.

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00:09:45.430 --> 00:09:57.839

Pam Marsh: As a concerned legislature, I have been immersed in this issue for the last 18 months. We've made some progress understanding the issue and identifying possible responses, but it is abundantly

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00:09:57.840 --> 00:10:16.739

Pam Marsh: abundantly clear that we now need third-party guidance to help frame the problem and identify the financial, legal, and policy solutions. And we need to move quickly. If the study you are contemplating recommends legislative action, we need to have proposals ready for the 2027 session.

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00:10:16.790 --> 00:10:18.669

Pam Marsh: There is no time to waste.

76

00:10:18.780 --> 00:10:25.389

Pam Marsh: Thank you so much for the opportunity to speak to you, but most of all, thank you for moving this work forward.

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00:10:27.340 --> 00:10:35.459

Chair Letha Tawney - Oregon PUC: Thank you so much, Representative Marsh. I appreciate, how thoughtful you have been on the issue and the complex nuances.

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00:10:35.760 --> 00:10:40.640

Chair Letha Tawney - Oregon PUC: Particularly given how impacted your community was in 2020.

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00:10:42.100 --> 00:10:44.780

Chair Letha Tawney - Oregon PUC: Tucker.

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00:10:47.910 --> 00:10:55.690

Tucker Billman, ORECA: Yeah, thank you, Chair Taney. Good morning, to you and to Commissioner Perkins and Power. I wanna...

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00:10:55.710 --> 00:11:14.040

Tucker Billman, ORECA: Just start by getting on the record my name, Tucker Billman, I'm the Director of Government Relations for the Oregon Rural Electric Cooperative Association, or ORECA. As you all know, ORECA represents Oregon's 18 not-for-profit electric cooperatives who serve significant portions of Oregon's high-fire risk areas and roughly 500,000 Oregonians.

82

00:11:14.070 --> 00:11:33.550

Tucker Billman, ORECA: Before diving into the study, I want to thank the Commission for this opportunity to provide comment, and I also want to thank Representative Marsh for her continued leadership on this topic. She has been a legislative champion trying to solve one of the state's most challenging issues, and Oregon's electric co-ops are grateful for her work here. We are also grateful for the PUC's leadership and work alongside of her efforts.

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00:11:33.820 --> 00:11:49.539

Tucker Billman, ORECA: ORECA appreciates the PUC's urgency in implementing this study. We feel strongly that the study should at least have a preliminary report available early in the fall of 2026, if not sooner, to ensure that the legislature has the time needed to make preparations for the 2020 legislative session.

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00:11:49.750 --> 00:12:07.660

Tucker Billman, ORECA: Oregon's electric cooperatives firmly believe that wildfire liability threatens our solvency. We accept our responsibility to safely, reliably, and affordably serve our communities. It is our job to meet industry standards and to reduce our wildfire risk. We have served high-fire risk areas throughout Oregon for 80-plus years, and we have a track record of success.

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00:12:07.740 --> 00:12:22.189

Tucker Billman, ORECA: When Senate Bill 762 passed, we codified the practices we utilized over those 80 years and combined them with cutting-edge technology to formalize our wildfire mitigation plans. As you all well know, all 18 electric cooperatives have wildfire mitigation plans filed with the PUC.

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00:12:22.810 --> 00:12:35.549

Tucker Billman, ORECA: We have not, and will not, take the challenge of mitigating wildfire lightly. However, unbounded wildfire liability poses an existential threat to co-op solvency. Judgments, even in the tens of millions of dollars, could lead to co-op bankruptcy.

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00:12:35.550 --> 00:12:45.690

Tucker Billman, ORECA: Wildfire insurance won't fix this problem. As Laura so adeptly pointed out, the wildfire insurance market for electric cooperatives is precarious, with shrinking capacity and escalating premiums.

88

00:12:45.690 --> 00:12:56.599

Tucker Billman, ORECA: We encourage the study team to engage directly with Federated Rural Electric Insurance Exchange to fully understand the current coverage constraints, market dynamics, and insurability challenges facing Oregon's electric co-ops.

89

00:12:56.900 --> 00:13:12.040

Tucker Billman, ORECA: Liability pressures are also driving significant annual increases in mitigation investments, which translate into upward rate pressure for member owners. Some cooperatives estimate that the equivalent of two monthly bills per year paid by an average electric co-op member can be attributed to wildfire mitigation work.

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00:13:12.040 --> 00:13:25.529

Tucker Billman, ORECA: We appreciate that the Commission plans to evaluate this affordability impact, and we encourage the Commission to consult with on-the-ground operators at electric cooperatives across the state to capture practical insights into mitigation spending, operational trade-offs, and rate effects.

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00:13:26.300 --> 00:13:37.140

Tucker Billman, ORECA: Finally, please keep in view a foundational reality. Electric cooperatives exist where others would not serve nearly a century ago. And candidly, many would still choose not to serve there today.

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00:13:37.400 --> 00:13:42.990

Tucker Billman, ORECA: Any policy path that overlooks this reality risks destabilizing essential service in rural Oregon.

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00:13:42.990 --> 00:13:57.549

Tucker Billman, ORECA: We respectfully request that the study's recommendation preserve the cooperative business model, ensure long-term service viability, and align safety, reliability, and affordability for the communities that depend on us. I'm happy to answer any questions, and again, thank you for the time and the leadership on the issue.

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00:13:59.290 --> 00:14:07.659

Chair Letha Tawney - Oregon PUC: Thank you so much. I appreciate you highlighting, in particular, the challenge of serving your communities. We've struggled with this with telco.

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00:14:08.000 --> 00:14:15.060

Chair Letha Tawney - Oregon PUC: Enormously, and so the service you provide to rural Oregon is... is absolutely critical.

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00:14:15.440 --> 00:14:16.379

Tucker Billman, ORECA: Thank you, honey.

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00:14:16.580 --> 00:14:18.799

Chair Letha Tawney - Oregon PUC: Any questions for... for Tucker?

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00:14:19.620 --> 00:14:21.870

Chair Letha Tawney - Oregon PUC: No. Okay, thank you.

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00:14:22.770 --> 00:14:24.260

Chair Letha Tawney - Oregon PUC: Jennifer?

100

00:14:29.990 --> 00:14:31.720

Jennifer Hill-Hart, Oregon CUB (she/her): Good morning, Chair Taney.

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00:14:31.720 --> 00:14:53.450

Jennifer Hill-Hart, Oregon CUB (she/her): Commissioner Perkins, Commissioner Power, thank you for the opportunity to comment on this, docket. PUB is grateful the Commission is opening up a docket like this. We've been involved in the legislature, having lots of conversations about utility wildfire liability, and it really doesn't... hasn't seemed to create enough time for the important, robust conversation we must have.

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00:14:53.550 --> 00:15:13.819

Jennifer Hill-Hart, Oregon CUB (she/her): As you know, this issue is really important for ratepayers, because we need to help keep utilities financially solvent, so it doesn't harm ratepayers, as far as, like, increasing costs, and also, you know, make sure that we are adequately providing for

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00:15:13.820 --> 00:15:17.150

Jennifer Hill-Hart, Oregon CUB (she/her): the needs of the companies, as well, for...

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00:15:17.330 --> 00:15:32.839

Jennifer Hill-Hart, Oregon CUB (she/her): other investments that they have. And yep, we're really grateful the Commission's taking this on. We need some leadership here, and we just encourage the Commission to make sure that folks who were engaged to this legislature are at the table,

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00:15:33.380 --> 00:15:45.669

Jennifer Hill-Hart, Oregon CUB (she/her): Just so we can make sure we have this robust conversation that is addressing, you know, as much concerns as we can. And, you know, do want to make sure that we are wrapping this up in time to have

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00:15:45.950 --> 00:15:49.950

Jennifer Hill-Hart, Oregon CUB (she/her): You know, something ready to go for this session that, you know, we can have,

107

00:15:50.180 --> 00:16:05.269

Jennifer Hill-Hart, Oregon CUB (she/her): as best... as much agreement as we can have, on something to move forward with, because this is an issue that applies to, you know, affects all of our electric utilities, so we need to be prepared. Yeah, thank you so much for your time, and I'm happy to answer any questions if you have.

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00:16:07.200 --> 00:16:09.669

Chair Letha Tawney - Oregon PUC: Thank you, Jennifer. I appreciate Cubs.

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00:16:10.150 --> 00:16:17.660

Chair Letha Tawney - Oregon PUC: Thoughtful balancing of ratepayers and the challenges that climate adaptation presents to ratepayers.

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00:16:18.990 --> 00:16:20.540

Chair Letha Tawney - Oregon PUC: Questions for Jennifer?

111

00:16:21.440 --> 00:16:24.950

Chair Letha Tawney - Oregon PUC: No. Great. Thanks for coming this morning.

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00:16:26.230 --> 00:16:34.240

Chair Letha Tawney - Oregon PUC: Any other comments on this item? I know we did receive some written comments that we reviewed that are attached to the agenda.

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00:16:35.360 --> 00:16:36.979

Chair Letha Tawney - Oregon PUC: I appreciate those.

114

00:16:40.170 --> 00:16:40.980

Chair Letha Tawney - Oregon PUC: Okay.

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00:16:42.110 --> 00:16:52.500

Chair Letha Tawney - Oregon PUC: Well, let's turn to deliberation. I'd like to start... I think this...

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00:16:53.150 --> 00:17:00.089

Chair Letha Tawney - Oregon PUC: Expert review of the policy options before us, before the state, is really essential.

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00:17:01.110 --> 00:17:07.200

Chair Letha Tawney - Oregon PUC: the Oregon Energy Strategy laid out... A vision of,

118

00:17:07.369 --> 00:17:10.290

Chair Letha Tawney - Oregon PUC: What decarbonizing the economy will require.

119

00:17:11.130 --> 00:17:14.620

Chair Letha Tawney - Oregon PUC: And, as we've talked about before.

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00:17:14.859 --> 00:17:21.119

Chair Letha Tawney - Oregon PUC: It's clear that that is lower cost than doing nothing, but requires really substantial capital.

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00:17:21.490 --> 00:17:24.880

Chair Letha Tawney - Oregon PUC: The set of capital investments in the electric sector.

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00:17:25.520 --> 00:17:33.079

Chair Letha Tawney - Oregon PUC: And... I think, the interplay of trying to...

123

00:17:33.580 --> 00:17:40.430

Chair Letha Tawney - Oregon PUC: Find, draw into the state at a low cost that scale of capital.

124

00:17:40.570 --> 00:17:45.020

Chair Letha Tawney - Oregon PUC: in order to provide the essential services that Tucker pointed to.

125

00:17:46.070 --> 00:17:49.639

Chair Letha Tawney - Oregon PUC: Is really challenged by the current

126

00:17:49.760 --> 00:17:54.960

Chair Letha Tawney - Oregon PUC: Construct of... of completely uncapped wildfire liability.

127

00:17:56.280 --> 00:18:04.849

Chair Letha Tawney - Oregon PUC: I don't think... That means No wildfire liability is necessary.

128

00:18:05.230 --> 00:18:17.599

Chair Letha Tawney - Oregon PUC: In order to move that capital. But I think some sense of the scale of risk is necessary in order to mobilize the capital Oregon policymakers want to deploy.

129

00:18:17.870 --> 00:18:20.020

Chair Letha Tawney - Oregon PUC: At a reasonable cost to ratepayers.

130

00:18:20.560 --> 00:18:28.429

Chair Letha Tawney - Oregon PUC: And I think getting some expertise around what is... how do you balance

131

00:18:29.360 --> 00:18:32.899

Chair Letha Tawney - Oregon PUC: That need for low-cost capital with the...

132

00:18:33.050 --> 00:18:36.980

Chair Letha Tawney - Oregon PUC: need for accountability? How do you set out

133

00:18:37.500 --> 00:18:42.670

Chair Letha Tawney - Oregon PUC: Boundaries and... and incentives to drive safety.

134

00:18:43.370 --> 00:18:47.720

Chair Letha Tawney - Oregon PUC: But also enable access to essential services.

135

00:18:47.870 --> 00:18:51.659

Chair Letha Tawney - Oregon PUC: We need some guidance on how to do that.

136

00:18:53.960 --> 00:19:00.759

Chair Letha Tawney - Oregon PUC: And I am... Really concerned about the scale of wildfire mitigation spending.

137

00:19:01.140 --> 00:19:06.239

Chair Letha Tawney - Oregon PUC: We've seen in California, That spending really ballooned.

138

00:19:06.610 --> 00:19:13.530

Chair Letha Tawney - Oregon PUC: the utilities last year in California, the large IOUs spent more than $9 billion

139

00:19:13.710 --> 00:19:17.400

Chair Letha Tawney - Oregon PUC: Trying to drive ignitions to zero.

140

00:19:19.450 --> 00:19:26.139

Chair Letha Tawney - Oregon PUC: $9 billion were not spent on any other sort of wildfire mitigation or risk reduction.

141

00:19:26.610 --> 00:19:30.119

Chair Letha Tawney - Oregon PUC: And they still experienced the January fires.

142

00:19:30.680 --> 00:19:37.269

Chair Letha Tawney - Oregon PUC: that were incredibly devastating. And I am very concerned about Oregon sort of following

143

00:19:37.690 --> 00:19:45.589

Chair Letha Tawney - Oregon PUC: That path of just spending to try to drive ignitions from one source to zero.

144

00:19:46.070 --> 00:19:57.739

Chair Letha Tawney - Oregon PUC: And potentially failing. I mean, if the California utilities couldn't drive ignitions to zero, I really worry about whether we will be able to, at any sort of reasonable cost.

145

00:19:58.110 --> 00:20:04.480

Chair Letha Tawney - Oregon PUC: And that's only one source of ignitions. The communities still face enormous risk.

146

00:20:05.120 --> 00:20:10.240

Chair Letha Tawney - Oregon PUC: And fundamentally, we have to reduce that community-level risk.

147

00:20:10.370 --> 00:20:15.940

Chair Letha Tawney - Oregon PUC: to catastrophe, As opposed to being centered exclusively on ignitions.

148

00:20:16.150 --> 00:20:25.589

Chair Letha Tawney - Oregon PUC: I'm really... anxious to see how, sort of, lessons learned from across the West might inform us

149

00:20:25.690 --> 00:20:29.939

Chair Letha Tawney - Oregon PUC: Inform our ability to balance those needs more effectively.

150

00:20:30.650 --> 00:20:34.910

Chair Letha Tawney - Oregon PUC: Oregon can't afford to replicate California.

151

00:20:35.140 --> 00:20:37.829

Chair Letha Tawney - Oregon PUC: Either in the spend by the utilities.

152

00:20:38.210 --> 00:20:42.900

Chair Letha Tawney - Oregon PUC: Or the continued disasters. And we have to arrive at something different.

153

00:20:43.440 --> 00:20:50.289

Chair Letha Tawney - Oregon PUC: Because our communities just can't afford the path that has played out in California.

154

00:20:51.800 --> 00:21:08.180

Chair Letha Tawney - Oregon PUC: So, I'm really looking forward to seeing the options that are brought forward and supporting a conversation amongst the policymakers who can give us direction on how they'd like to balance. In the meantime, we'll keep doubling down.

155

00:21:08.610 --> 00:21:12.280

Chair Letha Tawney - Oregon PUC: On driving of affordable safety outcomes, but...

156

00:21:12.550 --> 00:21:15.270

Chair Letha Tawney - Oregon PUC: I'm really... I'm really supportive of...

157

00:21:15.770 --> 00:21:25.009

Chair Letha Tawney - Oregon PUC: Of bringing some of that external expertise into the conversation so we can better understand what our options and trade-offs are, and how we can get

158

00:21:25.350 --> 00:21:31.249

Chair Letha Tawney - Oregon PUC: What sort of safety outcomes we need in communities where we've really reduced the risk of catastrophe.

159

00:21:31.580 --> 00:21:37.140

Chair Letha Tawney - Oregon PUC: At a more affordable... Price, and retained access to essential services.

160

00:21:37.440 --> 00:21:42.410

Chair Letha Tawney - Oregon PUC: So, I support this effort and really look forward to

161

00:21:43.480 --> 00:21:47.790

Chair Letha Tawney - Oregon PUC: Seeing what it brings into the conversation as we try to find our way through this.

162

00:21:47.910 --> 00:21:51.139

Chair Letha Tawney - Oregon PUC: Through this path, through this, thicket.

163

00:21:51.630 --> 00:22:00.430

Chair Letha Tawney - Oregon PUC: So, I support the motion. I'm, really interested in what, what, how you both see the, the issue.

164

00:22:03.350 --> 00:22:22.670

Comm. Les Perkins - OPUC: Thank you, Chair Taney. Well, first, I just want to thank you, and Representative Marsh, you've both done a lot in this arena, as have many others, Cub, ARECA, like, there's been all kinds of folks trying to figure out how to find a path forward for Oregon. I also just want to appreciate the work that staff did.

165

00:22:22.670 --> 00:22:34.540

Comm. Les Perkins - OPUC: to quickly get this put together, and to be creative, and figure out how to get it together, get it funded, and, keep a process that has integrity and that folks can trust in. So, and...

166

00:22:34.570 --> 00:22:44.540

Comm. Les Perkins - OPUC: The funding side, really appreciate the utilities, being willing to step up, to be able... because there's really not a lot of other options of how we could get this done, especially in the timeframe that we have before us.

167

00:22:44.750 --> 00:22:53.300

Comm. Les Perkins - OPUC: I'm 100%, in support of this moving forward. We just need the clarity of what our options are. Laid on the table.

168

00:22:53.840 --> 00:23:07.510

Comm. Les Perkins - OPUC: fully vetted so that policymakers, regulators, utilities, everybody can have some comfort in what those options are, what the trade-offs are. So, I'm fully, in support.

169

00:23:09.380 --> 00:23:17.550

Comm. Karin Power - Oregon PUC (she/her): And Chair Tani, I think both of you have eloquently laid out the multi-year case, you know, for us taking up the study right now.

170

00:23:17.920 --> 00:23:23.350

Comm. Karin Power - Oregon PUC (she/her): After the public's had an opportunity to weigh in on the state energy strategy, and...

171

00:23:23.490 --> 00:23:34.079

Comm. Karin Power - Oregon PUC (she/her): you know, legislators are eager to see this work move ahead to inform their policy conversations. I think it's an important part of our job as we evaluate

172

00:23:34.160 --> 00:23:43.749

Comm. Karin Power - Oregon PUC (she/her): utility spend and consumer costs, and I, too, am eager to see this work advance, and keep us...

173

00:23:44.070 --> 00:23:49.300

Comm. Karin Power - Oregon PUC (she/her): in line with our colleagues in neighboring states. So, thank you.

174

00:23:52.370 --> 00:23:53.410

Chair Letha Tawney - Oregon PUC: Thanks for that.

175

00:23:53.520 --> 00:23:59.630

Chair Letha Tawney - Oregon PUC: Well, then I'll move. We adopt staff's, proposed commission motion.

176

00:23:59.990 --> 00:24:00.929

Comm. Les Perkins - OPUC: I will second.

177

00:24:01.290 --> 00:24:02.319

Comm. Karin Power - Oregon PUC (she/her): And I'll concur.

178

00:24:02.660 --> 00:24:09.849

Chair Letha Tawney - Oregon PUC: Excellent. The move is adopted, and I'll look forward to the RFP unfolding.

179

00:24:10.570 --> 00:24:21.499

Chair Letha Tawney - Oregon PUC: Thanks, and I'll echo, Commissioner Perkins, thanks to staff for working so hard, and DAS for working so hard to, move this forward in a timely way.

180

00:24:23.360 --> 00:24:24.430

Chair Letha Tawney - Oregon PUC: Okay.

181

00:24:25.480 --> 00:24:29.180

Chair Letha Tawney - Oregon PUC: Let's move on to RA3.

182

00:24:29.370 --> 00:24:32.140

Chair Letha Tawney - Oregon PUC: Docket UM2419.

183

00:24:32.570 --> 00:24:41.489

Chair Letha Tawney - Oregon PUC: Deferred accounting requests related to the Coos County Pipeline. Will, Wheeler, I think you'll introduce it.

184

00:24:42.430 --> 00:24:47.100

Chair Letha Tawney - Oregon PUC: And then we'll take public comments, so I, I, I see you there, Mr. Totland.

185

00:24:47.880 --> 00:24:48.959

Chair Letha Tawney - Oregon PUC: Go ahead, Will.

186

00:24:49.040 --> 00:24:57.619

Will Wheeler - OPUC (he/him): Thank you, and good morning, Chair Taney, Commissioner Perkins, and Commissioner Power. For the record, my name is Will Wheeler, and I am representing PUC staff.

187

00:24:57.640 --> 00:25:11.010

Will Wheeler - OPUC (he/him): I'm joined by Staff Council Stephanie Andrus. Today, I will present staff's recommendation in UM2419 regarding Northwest Natural's application to defer certain costs and revenues associated with the Coos County Pipeline.

188

00:25:11.440 --> 00:25:25.150

Will Wheeler - OPUC (he/him): In its application, Northwest Natural is seeking to defer 2026 Operations and Maintenance, or O&M, costs for the pipeline, along with revenues from Schedule 160, the 2 cent per therm surcharge that Coos County customers pay.

189

00:25:25.410 --> 00:25:35.219

Will Wheeler - OPUC (he/him): The company's plan is to acquire the pipeline from Coos County to perform landslide remediation and mitigation work that Coos County cannot fund as the current owner.

190

00:25:35.390 --> 00:25:51.429

Will Wheeler - OPUC (he/him): Northwest Natural states that the work will require both capital investments and larger-than-typical O&M expenses that cannot be done by it unless it is the owner. The question the Commission is considering today is whether to allow the company to track the O&M expenses through a deferral.

191

00:25:51.940 --> 00:26:03.639

Will Wheeler - OPUC (he/him): To provide a little background, the Coos County Pipeline is a roughly 60-mile pipeline connecting Northwest Natural's Coos County Distribution System to the Williams Interstate Pipeline, and has been in service since 2005.

192

00:26:04.030 --> 00:26:13.310

Will Wheeler - OPUC (he/him): The pipeline was constructed using funds allocated from the state legislature, and a general obligation bond approved by Coos County voters, and is currently owned by Coos County.

193

00:26:13.700 --> 00:26:22.369

Will Wheeler - OPUC (he/him): Over the past 20 years, Northwest Natural has served as operator of the pipeline, and has recovered O&M expenses for the pipeline through an agreement with the county.

194

00:26:22.900 --> 00:26:33.130

Will Wheeler - OPUC (he/him): Northwest Natural has reported that the pipeline is at risk of safety and reliability issues due to landslide activity in the area that urgently needs to be addressed following a 2021 study.

195

00:26:34.100 --> 00:26:50.749

Will Wheeler - OPUC (he/him): Heavy storms in March 2025 exacerbated the landslide risk. Coos County states that it cannot secure the funds necessary to complete the work. In

response, Northwest Natural plans to acquire the pipeline from Coos County for $1 to conduct the mitigation work.

196

00:26:51.670 --> 00:27:10.949

Will Wheeler - OPUC (he/him): This deferral application has received substantial comments from stakeholders. Many local governments and organizations in Coos County filed comments in support of the plan, highlighting the importance of continued safe and reliable natural gas service, economic activity supported by the pipeline, and the high costs of switching to an alternative energy source.

197

00:27:11.520 --> 00:27:32.680

Will Wheeler - OPUC (he/him): The Green Energy Institute at Lewis and Clark Law School, Rogue Climate, and the Sierra Club expressed concern about whether the extent of the costs and repairs necessary match the benefits received by a potentially declining number of customers, and urged the Commission to consider this as an opportunity for zonal electrification and the exploration of non-pipes alternatives.

198

00:27:33.600 --> 00:27:46.219

Will Wheeler - OPUC (he/him): Cubb filed comments arguing that the filing does not satisfy the criteria for a deferral. Cub also expressed concern that this deferral application was being used to provide backdoor approval for Northwest Natural's purchase of the pipeline.

199

00:27:46.470 --> 00:28:00.939

Will Wheeler - OPUC (he/him): Cub encouraged the Commission to deny the deferral request and instead allow normal regulatory lag for these costs, or, if the deferral is

accepted, to make crystal clear that the deferral is not assuring cost recovery for any Coos County pipeline costs.

200

00:28:01.440 --> 00:28:20.839

Will Wheeler - OPUC (he/him): Northwest Natural filed response comments, though time constraints prevented addressing these in the staff memo. It argues that denial of this application would not create normal regulatory lag, because it could not have incorporated these costs into rates, as it is not the current owner, and reiterated its claim that this deferral reduces the frequency of rate changes.

201

00:28:21.090 --> 00:28:30.389

Will Wheeler - OPUC (he/him): Northwest Natural urged the Commission to focus on the safety issues that need to be addressed, and asked that it would not be denied cost recovery solely for acquiring the pipeline.

202

00:28:31.090 --> 00:28:48.509

Will Wheeler - OPUC (he/him): Staff would like to thank all of the stakeholders who participated in this process for their timely and thoughtful feedback provided through meetings and written comments. Staff notes that allocation for costs related to the pipeline has not yet been determined, and will thoroughly explore that issue in the relevant cost recovery dockets.

203

00:28:48.730 --> 00:28:58.259

Will Wheeler - OPUC (he/him): Staff also acknowledges the concerns raised regarding electrification, and is similarly committed to finding viable opportunities to test beneficial electrification models.

204

00:28:58.480 --> 00:29:07.769

Will Wheeler - OPUC (he/him): But worries that electrification proposals here may not be well aligned with local community feedback or near-term timelines for core decisions regarding the pipeline.

205

00:29:09.010 --> 00:29:26.000

Will Wheeler - OPUC (he/him): Staff believes that the Commission should approve Northwest Natural's deferral request. While staff disagrees with Cub's position on statutory criteria, staff agrees that the amounts expected to be deferred are small, and believes that it is improper to approve a deferral simply for containing unforeseen costs.

206

00:29:26.190 --> 00:29:36.429

Will Wheeler - OPUC (he/him): Staff acknowledges that the use of deferrals has increased too much recently, and is committed to addressing the overuse of deferrals in the implementation of HB 3179.

207

00:29:36.930 --> 00:29:48.969

Will Wheeler - OPUC (he/him): However, staff believes that the circumstances here are unique, with Northwest Natural acquiring a pipeline with possibly imminent safety risks from an entity that cannot make the repairs itself.

208

00:29:49.550 --> 00:29:57.329

Will Wheeler - OPUC (he/him): In making this recommendation, staff reiterates that approval of this deferral does not constitute pre-approval of any of the costs that are tracked.

209

00:29:57.490 --> 00:30:02.430

Will Wheeler - OPUC (he/him): Prudence determination will occur at the time that the company requests to recover these costs.

210

00:30:03.060 --> 00:30:15.190

Will Wheeler - OPUC (he/him): To provide guidance to the company regarding that prudence investigation, staff provided in its memo an expectation for the types of information it would closely examine, including exploration of non-pipes alternatives.

211

00:30:15.620 --> 00:30:23.759

Will Wheeler - OPUC (he/him): With that, staff recommends that the Commission approve Northwest Natural's application. This concludes my opening remarks, and I am available for questions.

212

00:30:26.150 --> 00:30:32.890

Chair Letha Tawney - Oregon PUC: Thank you so much, Will. I found the staff memo very, very thorough, and I appreciated the...

213

00:30:33.200 --> 00:30:40.220

Chair Letha Tawney - Oregon PUC: laying out, in particular, procedurally, where we're at in this process. Any questions for... for staff?

214

00:30:42.620 --> 00:30:44.069

Chair Letha Tawney - Oregon PUC: Nope? Okay.

215

00:30:44.820 --> 00:30:46.059

Chair Letha Tawney - Oregon PUC: Thanks so much, Will.

216

00:30:46.480 --> 00:30:53.999

Chair Letha Tawney - Oregon PUC: All right, so let me ask for a show of hands. Raise your hand if you'd like to comment on this issue.

217

00:30:54.460 --> 00:30:59.400

Chair Letha Tawney - Oregon PUC: I see Zach and Bob,

218

00:31:00.550 --> 00:31:04.080

Chair Letha Tawney - Oregon PUC: And I know we had a... somebody from Coos County

219

00:31:04.970 --> 00:31:08.490

Chair Letha Tawney - Oregon PUC: Who popped on earlier, so if you...

220

00:31:08.660 --> 00:31:12.230

Chair Letha Tawney - Oregon PUC: like to comment as well.

221

00:31:12.460 --> 00:31:13.290

jsweet: There we go.

222

00:31:13.560 --> 00:31:15.090

Chair Letha Tawney - Oregon PUC: Commissioner Sweet, I believe?

223

00:31:15.090 --> 00:31:15.940

jsweet: morning.

224

00:31:15.940 --> 00:31:21.970

Chair Letha Tawney - Oregon PUC: Good morning. I'll take you first, since you're from the community, and then we'll loop around to the other stakeholders.

225

00:31:22.210 --> 00:31:27.979

jsweet: Thank you. Well, good morning to Chair Taney and Commissioners Power and Perkins. Can you hear okay?

226

00:31:28.250 --> 00:31:29.020

Chair Letha Tawney - Oregon PUC: Yes, sir.

227

00:31:29.020 --> 00:31:41.619

jsweet: I'm John Sweet, Coos County Commissioner. First, I want to thank the Oregon PUC and Northwest Natural for moving this process ahead. The loss of natural gas service would devastate our county.

228

00:31:41.820 --> 00:31:50.279

jsweet: And yet another thank you is due to Northwest Natural. We could not ask for a better corporate partner than they have been.

229

00:31:50.630 --> 00:32:08.470

jsweet: Natural gas has become a primary source of energy for our county, particularly for those companies that are providing family wage jobs. Its use spans many economic sectors, agriculture, tourism, healthcare, education, manufacturing, and commercial.

230

00:32:08.700 --> 00:32:13.670

jsweet: Some 1,900 family homes now depend on natural gas in the county.

231

00:32:13.970 --> 00:32:21.780

jsweet: Unfortunately, our pipeline is at risk of failure due to landslides and floods caused by heavy rains.

232

00:32:21.960 --> 00:32:33.610

jsweet: As described below, Coos County simply does not have the financial resources to make the lasting repairs needed to protect the pipeline from these events over time.

233

00:32:34.150 --> 00:32:35.570

jsweet: As you know.

234

00:32:35.720 --> 00:32:50.059

jsweet: The pipeline was partially funded by a State of Oregon grant, and in the larger part, by a bond levy approved and paid for by county citizens. The bonds have been paid off in full.

235

00:32:50.200 --> 00:33:06.980

jsweet: After construction was completed, remaining bond revenues and proceeds from a lawsuit against a negligent pipeline contractor were set aside as a maintenance reserve. A rate surcharge was enacted to provide for O&M costs.

236

00:33:07.700 --> 00:33:11.109

jsweet: In fact, the ON cost, ref...

237

00:33:11.610 --> 00:33:23.809

jsweet: or the proceeds of the rate surcharge were fully consumed by O&M costs, leaving nothing to supplement the maintenance reserve.

238

00:33:24.230 --> 00:33:32.109

jsweet: The county did obligate another $1.45 million of ARPA funds to the reserve.

239

00:33:32.260 --> 00:33:41.680

jsweet: Despite that, the reserve has been spent down on major repairs to a current level of roughly $2 million.

240

00:33:42.430 --> 00:33:53.509

jsweet: Northwest Natural projects that $12.5 million of lasting repairs are needed to restore the pipeline to safe working conditions.

241

00:33:54.100 --> 00:33:58.260

jsweet: We have sought grants for repairs, but none have been awarded.

242

00:33:59.160 --> 00:34:05.149

jsweet: Our county is simply not in a position to pay for the needed pipeline maintenance.

243

00:34:05.410 --> 00:34:12.369

jsweet: We are struggling to provide even basic county services such as public safety and voting.

244

00:34:12.920 --> 00:34:17.129

jsweet: Pre-COVID, we were barely able to keep our nose above water.

245

00:34:17.530 --> 00:34:26.659

jsweet: Post-COVID inflation, combined with a limit on property tax increases imposed by measures 5 and 50, has been a killer.

246

00:34:26.969 --> 00:34:32.379

jsweet: For two years now, the county budget has been largely balanced through staff reductions.

247

00:34:32.600 --> 00:34:36.469

jsweet: 50% of our jail capacity has been shut down.

248

00:34:36.600 --> 00:34:43.070

jsweet: Only the more serious crimes are prosecuted due to reductions in DA staffing.

249

00:34:43.350 --> 00:34:48.749

jsweet: I'm anticipating that road patrol will be eliminated in next year's budget.

250

00:34:49.219 --> 00:34:53.780

jsweet: These are but a few examples of our efforts to balance our budget.

251

00:34:54.380 --> 00:34:59.889

jsweet: It's a picture common to many local jurisdictions, and it's not a pretty one.

252

00:35:00.200 --> 00:35:11.110

jsweet: The point for this conversation is that we desperately need to transfer ownership of the county's gas pipeline to a better funded organization.

253

00:35:11.580 --> 00:35:16.300

jsweet: And with that, I conclude my testimony. I'm happy to answer questions.

254

00:35:18.560 --> 00:35:22.600

Chair Letha Tawney - Oregon PUC: Thank you very much, Commissioner Sweet. Any questions for the Commissioner?

255

00:35:24.480 --> 00:35:37.160

Chair Letha Tawney - Oregon PUC: Yeah, thank you. And I, I note we, received a wide range of comments, written comments, as well in the docket from the Coos County, community, so, thank you for that.

256

00:35:37.560 --> 00:35:38.380

jsweet: You're welcome.

257

00:35:39.070 --> 00:35:54.440

Chair Letha Tawney - Oregon PUC: Alright, let me turn to, Bob, Jenks with Cub, and then we'll, we'll end with the company. So if there are other folks who would like to, speak, if you can raise your hand, that would be great.

258

00:35:54.770 --> 00:35:55.880

Chair Letha Tawney - Oregon PUC: Bob.

259

00:35:56.190 --> 00:35:58.499

Bob Jenks, Oregon CUB, he/him: Great, thank you, Commissioner.

260

00:35:58.760 --> 00:36:05.760

Bob Jenks, Oregon CUB, he/him: For the record, my name's Bob Jenks. I'm the Executive Director of Oregon's Citizens Utility Board.

261

00:36:05.760 --> 00:36:27.760

Bob Jenks, Oregon CUB, he/him: Let me start by saying that I personally love Oregon's Bay Area. I have good friends who have moved to both Coos Bay and Coquille, my uncle retired to Bandon, and my mom lived for years in Brookings, which is further south, but we went through Oregon's Bay Area on semi-annual visits. Coos Bay, North Bend, Coquille, Bandon, Charleston are all wonderful communities.

262

00:36:28.120 --> 00:36:40.640

Bob Jenks, Oregon CUB, he/him: The Coos Bay pipeline was built for economic development purposes to bring jobs to the port of Coos Bay. While the demand is below what was anticipated, there are industrial customers and jobs in Coos Bay that are dependent on this pipeline.

263

00:36:40.810 --> 00:36:59.339

Bob Jenks, Oregon CUB, he/him: CUB recognizes that closing the pipeline would cost jobs and have significant negative effects on the entire community. That is not CUB's goal. Though I also recognize that climate change is causing more and more extreme weather events that could threaten this pipeline, and that climate change is also creating the need to phase out fossil fuels.

264

00:37:00.330 --> 00:37:07.840

Bob Jenks, Oregon CUB, he/him: There are 3 important issues before the Commission. The first, and most immediate, is whether a deferral is appropriate rate treatment.

265

00:37:07.840 --> 00:37:24.229

Bob Jenks, Oregon CUB, he/him: The second and more complex, is what happens to the Coos Bay pipeline, and who pays for the costs associated with it. And the third is what we should... is whether we should tear up the stipulation between Northwest Natural Cubs staff and industrial customers and Coos Bay.

266

00:37:24.360 --> 00:37:35.289

Bob Jenks, Oregon CUB, he/him: Coos County, on how to recover the uneconomic costs of the distribution system, and if so, what replaces it? While the deferral is at issue today, these three issues are interrelated.

267

00:37:36.020 --> 00:37:47.770

Bob Jenks, Oregon CUB, he/him: I first want to address the deferral standard. There are two standards for deferrals, and I'm not an attorney, so I'm not trying to give a legal analysis, but I'm speaking from my experience practicing before the Commission.

268

00:37:47.820 --> 00:37:57.599

Bob Jenks, Oregon CUB, he/him: The first is minimizing rate changes. We have been in a major rate proceeding with Northwest Natural every month except two, since December 2023.

269

00:37:57.610 --> 00:38:08.980

Bob Jenks, Oregon CUB, he/him: Over the last year, we invented a new form of rate case called an ARM. With PGE, the arm was a case that was limited to costs and offsets that were negotiated in an MOU between stakeholders and the company.

270

00:38:09.030 --> 00:38:18.359

Bob Jenks, Oregon CUB, he/him: With Northwest Natural, there is no MOU. The utility seems to get to decide what costs and what offsets are included. And they may file another one in November. Why not?

271

00:38:18.560 --> 00:38:21.409

Bob Jenks, Oregon CUB, he/him: So whether we're minimizing rate changes.

272

00:38:21.600 --> 00:38:28.059

Bob Jenks, Oregon CUB, he/him: So rather than minimizing rate changes and cost recovery, we were actually making it easier for the company to change rates.

273

00:38:28.410 --> 00:38:39.410

Bob Jenks, Oregon CUB, he/him: The other criteria is matching costs and benefits. This is not about matching costs and benefits. This is part of a proposal by the company to actually mismatch costs and benefits.

274

00:38:39.610 --> 00:38:57.700

Bob Jenks, Oregon CUB, he/him: The Coos Bay Pipeline was built for economic development purposes. Only 15% of the gas that flowed through it in 2025 was used to serve residential customers. And Northwest Natural is now proposing that we shift these costs to the system with more than 66% of these costs paid by residential customers.

275

00:38:58.300 --> 00:39:03.070

Bob Jenks, Oregon CUB, he/him: The company also wants to mismatch costs and benefits of the distribution system.

276

00:39:03.160 --> 00:39:17.140

Bob Jenks, Oregon CUB, he/him: Expanding gas service is not based on universal service, but based on economics. When the Coos County pipeline was being developed, there was a need for additional load, and Northwest Natural wanted to build a local distribution system.

277

00:39:17.140 --> 00:39:23.390

Bob Jenks, Oregon CUB, he/him: There was a lot of political pressure to accept this, and place the cost primarily on the residential customers of the system.

278

00:39:23.630 --> 00:39:37.420

Bob Jenks, Oregon CUB, he/him: But from Cubs' perspective, an uneconomic expansion of the gas system due to political pressure would have created a terrible president. So we objected. We applied the normal standards to when the system will pay for expanding the system.

279

00:39:37.580 --> 00:39:47.630

Bob Jenks, Oregon CUB, he/him: And ended up with a stipulation that customers of the Northwest Natural System, again, primarily residential, pay the economic costs of expansion, or $10 billion.

280

00:39:47.630 --> 00:40:00.279

Bob Jenks, Oregon CUB, he/him: The costs above the economic expansion were split. Northwest Natural contributed $400,000, and the customers of the new distribution system were assigned $1.6 million through a 2 cent per therm surcharge.

281

00:40:00.490 --> 00:40:04.130

Bob Jenks, Oregon CUB, he/him: Cub was skeptical of Northwest Natural's load forecast, and our current

282

00:40:04.980 --> 00:40:23.700

Bob Jenks, Oregon CUB, he/him: Concerns were addressed by the agreement that said if after 20 years, the surcharge had not provided $1.6 million, within 3 months, Northwest Natural would identify what changes were needed to be made to the surcharge, and how long to collect it for the remaining amount. This stipulation still governs the distribution system.

283

00:40:23.860 --> 00:40:32.170

Bob Jenks, Oregon CUB, he/him: But Northwest Naturals proposed tearing up this agreement and sticking the costs on the system, again, with residential customers paying more than 66%.

284

00:40:32.630 --> 00:40:45.420

Bob Jenks, Oregon CUB, he/him: So we're not trying to match costs and benefits, we're trying to have the residential customers of the system bail out uneconomic investments in Coos County, in the Coos County pipeline and the distribution system.

285

00:40:47.370 --> 00:40:53.480

Bob Jenks, Oregon CUB, he/him: So the deferral does not minimize rate changes, and it does not match costs and benefits.

286

00:40:53.740 --> 00:41:02.870

Bob Jenks, Oregon CUB, he/him: The staff memo seemed to struggle with how do we justify this deferral, and they arrived at a new standard for deferrals that Cub strongly objects to.

287

00:41:05.260 --> 00:41:21.100

Bob Jenks, Oregon CUB, he/him: According to that staff memo, it is unfair to deny Northwest Natural's application to defer the costs of repairs on the grounds that Northwest Natural should have foreseen this cost and accounted for it in current rates, because this is not something Northwest Natural could do.

288

00:41:21.450 --> 00:41:38.880

Bob Jenks, Oregon CUB, he/him: CUB rejects the idea that it is unfair for a utility to make them absorb slightly more than $1 million of unforeseen costs. Utilities always have unforeseen costs, as do state agencies, as do nonprofits, as do households. This is simply an invitation for more deferrals.

289

00:41:39.090 --> 00:41:50.920

Bob Jenks, Oregon CUB, he/him: Ask yourself if it is unfair for a utility to keep $1 million in unforeseen savings, because unforeseen savings also occur, but rarely do we see those get passed through to customers.

290

00:41:51.710 --> 00:42:02.599

Bob Jenks, Oregon CUB, he/him: CUB's recommendation is to urge the Commission to reject deferring the unanticipated costs of Northwest Natural. They do not rise to the level of a deferral.

291

00:42:02.600 --> 00:42:12.770

Bob Jenks, Oregon CUB, he/him: If a deferral is needed to keep the county's surcharge in place, we are okay with deferring the revenues from that surcharge, because the stipulation we all agreed to

292

00:42:12.770 --> 00:42:22.700

Bob Jenks, Oregon CUB, he/him: clearly anticipated keeping the surcharge after 20 years if the cost of the distribution system has not been recovered, and that's the circumstances we're in.

293

00:42:22.880 --> 00:42:38.300

Bob Jenks, Oregon CUB, he/him: Thank you. I'm happy to answer questions, and as a note, CUB's counsel, Claire Valentine-Fossum, is here, if you have legal questions about the

deferral standard, and Emily Dugan from CUB is also here, and she's been taking the lead in analyzing this proposal.

294

00:42:40.740 --> 00:42:53.279

Chair Letha Tawney - Oregon PUC: Bob, I appreciate the history, and I do appreciate that this is... this issue is spread across a variety of dockets, and so I want to appreciate, as well, our AHD team.

295

00:42:53.650 --> 00:43:03.219

Chair Letha Tawney - Oregon PUC: putting notice in those... in those contested case dockets. So we... we can't necessarily engage on the contested case dockets today, but...

296

00:43:04.060 --> 00:43:15.440

Chair Letha Tawney - Oregon PUC: I'm curious... You're, agreeing to the deferral is not agreeing to amortization or, or the allocation of

297

00:43:15.660 --> 00:43:21.970

Chair Letha Tawney - Oregon PUC: Any deferred costs, eventual cost recovery of, of those deferred costs.

298

00:43:22.860 --> 00:43:24.469

Chair Letha Tawney - Oregon PUC: And I'm curious...

299

00:43:24.850 --> 00:43:44.850

Chair Letha Tawney - Oregon PUC: if you think that there is... if we agree to the deferral here, if we are somehow bound on a... on an amortization question, then to spread the costs across Northwest Natural's larger rate base, or if you're worried that that will be the proposal, and you're sort of prevent...

300

00:43:45.690 --> 00:43:48.279

Chair Letha Tawney - Oregon PUC: Preempt... trying to preempt that argument.

301

00:43:48.670 --> 00:43:59.359

Bob Jenks, Oregon CUB, he/him: Well, the two issues. One is that is Northwest Natural's proposal, is to put these costs onto the system and collect them

302

00:43:59.420 --> 00:44:22.960

Bob Jenks, Oregon CUB, he/him: primarily from residential customers. That's the effect of putting these on margin rates on the system. But the question that we're trying to raise is, are these eligible for a deferral? If they're not eligible for a deferral, we don't get to the amortization phase, we don't get to that stage. And the deferral orders from the Commission, from

303

00:44:22.960 --> 00:44:28.329

Bob Jenks, Oregon CUB, he/him: A decade ago, where we had a series of sort of deep dives looking at use of deferrals.

304

00:44:28.330 --> 00:44:46.760

Bob Jenks, Oregon CUB, he/him: clearly laid out sort of a two-step process, and the first step is to consider, is the cost eligible for a deferral? And we're extremely skeptical of that. Again, the standard that they're unforeseen to us is if we start saying unforeseen costs are eligible for a deferral.

305

00:44:46.760 --> 00:44:49.829

Bob Jenks, Oregon CUB, he/him: - we're gonna see more deferrals filed.

306

00:44:52.480 --> 00:45:07.019

Chair Letha Tawney - Oregon PUC: I, I appreciate that and recognize we're in a larger conversation around deferrals and the multi-year rate making, so I, I, it is an issue we have struggled with over the last several years. So, thank you.

307

00:45:07.720 --> 00:45:14.210

Chair Letha Tawney - Oregon PUC: I see, Claire, you've raised your hand. Do you want to add to something to what Bob is, arguing?

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00:45:14.480 --> 00:45:15.560

Chair Letha Tawney - Oregon PUC: We're raising?

309

00:45:17.440 --> 00:45:20.600

Claire Valentine-Fossum: Yes, thank you, Chair Tommy. Can you hear me okay?

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00:45:21.610 --> 00:45:39.889

Claire Valentine-Fossum: Great, thank you for that. And, before I wanna... before I do add to address some parts of your question to add a little bit more context to what Bob just said, I just want to first acknowledge that there are, varying count... Varying comments from Coos County residents in the public comments tab, in addition to those that were filed into the docket.

311

00:45:39.960 --> 00:45:56.789

Claire Valentine-Fossum: And as the commissioners know, we encourage engagement in commission proceedings, and we recognize it takes a lot of work to file a comment, and we appreciate the comments from all the residents that were in here. To your point, too, about, I think, kind of focusing on the, is this eligible for a deferral?

312

00:45:57.230 --> 00:46:15.229

Claire Valentine-Fossum: part of our concern, as to what Bob had noted earlier, is that this sets up a new standard whereby... so typically, of course, we're looking at the statute, we're looking at what is allowed, and then there's the discretionary stage, of the commission, and at that point, in that stage of the discretionary stage.

313

00:46:15.230 --> 00:46:31.720

Claire Valentine-Fossum: you're looking at both what is the event that caused the need for the deferral, so is this stochastic? Is this a scenario risk? That's where you're looking at, were these events, were these costs unseen? But you're also looking at the magnitude, and those are interrelated. So if we start to just focus on, is this foreseen.

314

00:46:31.720 --> 00:46:35.309

Claire Valentine-Fossum: Which, according... you know, and according to the staff report, says.

315

00:46:35.320 --> 00:46:43.680

Claire Valentine-Fossum: These are unique circumstances, notwithstanding the magnitude, then we kind of... then we start to get away from this other component of it.

316

00:46:43.680 --> 00:46:57.659

Claire Valentine-Fossum: Which was the focus of CUB's, opposition in here on that second stage, is that regardless of whether this is scenario or stochastic risk, the $1.3 million just... it doesn't get to the impact, the financial impact.

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00:46:57.770 --> 00:47:04.549

Claire Valentine-Fossum: Component that is part of that deferential, standard. And that's the same thing that

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00:47:04.670 --> 00:47:21.849

Claire Valentine-Fossum: the same position that the Commission has taken in 1623, when it denied PG's application for a deferred counting, where it said, this is less than 1% of the revenue, you just haven't gotten to the standard that we would need for the financial impact to the, to the utility. So that's sort of a...

319

00:47:21.860 --> 00:47:30.890

Claire Valentine-Fossum: Regardless of whether we're talking about stochastic or scenario, whether this was foreseen, there's an impact of what is the magnitude, to the... to the utility, and

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00:47:31.570 --> 00:47:37.530

Claire Valentine-Fossum: We just went from a conversation, right, about the impact of cost to customers when we're talking about wildfire.

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00:47:37.660 --> 00:47:51.209

Claire Valentine-Fossum: Very similarly, we're talking about the impact to costs here for customers, and while I recognize it's not an automatic, entry into rates, right, we have to go through, still through the amortization part of it, this is a part, like, this level.

322

00:47:51.500 --> 00:48:02.059

Claire Valentine-Fossum: of, is this warranted, is part of what the Commission, back when they were looking at deferrals, back in 2024, when the Commission said it would take a stricter stance on these type of mechanisms, like, we don't need to wait for the FAIR Act.

323

00:48:02.180 --> 00:48:05.400

Claire Valentine-Fossum: For this to happen, we can... the Commission could make a decision now on it.

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00:48:07.190 --> 00:48:08.980

Claire Valentine-Fossum: Thank you for that.

325

00:48:09.940 --> 00:48:17.919

Claire Valentine-Fossum: May I address one more other point that was made in terms of a legal question on the regulatory lag side of things? Sure. I believe there was a statement that,

326

00:48:18.290 --> 00:48:25.959

Claire Valentine-Fossum: this is not applicable for regulatory lag, which, of course, that was one of Cub's arguments, because this was not foreseen, these were not foreseen costs, again.

327

00:48:25.960 --> 00:48:39.009

Claire Valentine-Fossum: That's not the standard for regulatory lag. You can have unforeseen costs that happen between rate cases, that can be taken on as regulatory lag, much like there can be unforeseen earnings, or other revenue that, supports the regulatory lag.

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00:48:39.010 --> 00:48:41.050

Claire Valentine-Fossum: Of a utility. So, thank you.

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00:48:42.360 --> 00:48:44.150

Chair Letha Tawney - Oregon PUC: Thanks. I appreciate that.

330

00:48:44.660 --> 00:48:46.660

Chair Letha Tawney - Oregon PUC: Any questions for Cup?

331

00:48:49.430 --> 00:48:50.200

Chair Letha Tawney - Oregon PUC: No?

332

00:48:51.380 --> 00:48:52.190

Chair Letha Tawney - Oregon PUC: Okay.

333

00:48:52.790 --> 00:48:56.760

Chair Letha Tawney - Oregon PUC: Appreciate the, clear argumentation.

334

00:48:57.040 --> 00:48:58.670

Chair Letha Tawney - Oregon PUC: Okay.

335

00:48:59.590 --> 00:49:02.160

Chair Letha Tawney - Oregon PUC: And Zach with the company.

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00:49:09.390 --> 00:49:17.260

Zach Kravitz (NW Natural): Good morning, Chair Connie, Commissioner Perkins, Commissioner Power, Zach Kravitz, for West Natural,

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00:49:17.570 --> 00:49:20.269

Zach Kravitz (NW Natural): First off, I do want to,

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00:49:21.100 --> 00:49:33.029

Zach Kravitz (NW Natural): say thank you and, and appreciate all of staff, and really all of the stakeholders' work in this process. This is a complicated,

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00:49:33.110 --> 00:49:47.420

Zach Kravitz (NW Natural): process and, transaction, that has a lot of regulatory, aspects to it, and, staff has, and CUB and other, stakeholders have really,

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00:49:47.570 --> 00:50:04.950

Zach Kravitz (NW Natural): dived in and, and, worked really, well together to... to get us at least to this point. And we appreciate all the stakeholders' views, including the Coos County, community and... and Chair Sweet, who have,

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00:50:04.950 --> 00:50:12.750

Zach Kravitz (NW Natural): shared their views to support Northwest Natural's actions to ensure that the Coos County Pipeline can continue

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00:50:12.750 --> 00:50:27.130

Zach Kravitz (NW Natural): To provide safe and reliable service. And just generally, the interest of all stakeholders for the well-being of Coos County residents, our 2,300 customers there, that is a shared goal.

343

00:50:27.580 --> 00:50:46.410

Zach Kravitz (NW Natural): And while there are different points of view in terms of how to resolve this, ultimately, we view this decision as one of a priority safety matter for our friends in Coos County. Northwest Natural will step in, and we will make this pipeline safe.

344

00:50:46.470 --> 00:51:03.720

Zach Kravitz (NW Natural): We understand that this is a deferral docket, and cost recovery is not being decided here, and it is incumbent upon Northwest Natural to demonstrate that these investments that we are going to make, the capital investments, and, the,

345

00:51:03.720 --> 00:51:28.379

Zach Kravitz (NW Natural): repairs that fall into the expense category that would be subject to this deferral, that these are prudent actions. And ultimately, we understand that there will be a conversation as well around the allocation of these costs. Mr. Jenks is correct, we

did have a proposal, but we know that there are multiple... there will be other points of view, and that will be part

346

00:51:28.380 --> 00:51:40.089

Zach Kravitz (NW Natural): of another regulatory proceeding, and we will, engage in that there. And so we're not signaling in any way that anything is predetermined by this particular, application.

347

00:51:40.170 --> 00:51:54.629

Zach Kravitz (NW Natural): We do view this as an important step, in the regulatory process, to move forward, with our plans, to, to make these, repairs in, in the pipeline.

348

00:51:54.630 --> 00:52:06.950

Zach Kravitz (NW Natural): And, to the... with respect to some of the discussion around, the deferrals, we do agree with... with staff's analysis, on.

349

00:52:06.950 --> 00:52:24.430

Zach Kravitz (NW Natural): on this deferral, this does create some unique circumstances, around what can be... what is, foreseen, in particular in a situation where the utility is not the owner of the asset, and subsequent events,

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00:52:24.660 --> 00:52:32.150

Zach Kravitz (NW Natural): intervene and beca... and... changes some of these circumstances that we are facing, and so...

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00:52:32.150 --> 00:52:56.839

Zach Kravitz (NW Natural): that is an important aspect to this, and then as it relates to just ongoing regulatory lag, why is it not appropriate for that type of situation here? There's really not any way for Northwest Natural to otherwise recover these costs, because in large part, this is a one-time expense that we are going to be making.

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00:52:56.930 --> 00:53:01.999

Zach Kravitz (NW Natural): As it relates to certain repairs on the pipe, and it would not...

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00:53:02.100 --> 00:53:15.770

Zach Kravitz (NW Natural): it would not be appropriate for us to bring that forward in a rate case as some sort of routine annual recovery, which is how we set base rates. This kind of stands apart as a one-time cost, that we have not

354

00:53:16.190 --> 00:53:35.740

Zach Kravitz (NW Natural): previously recovered in base rates, so we do think it is appropriate in that respect. Appreciate all of your time. You've received our application and our written comments. If you have questions, we've got some internal folks here, but I... and obviously, Chair Sweet is here, and I'm happy to answer any questions.

355

00:53:37.540 --> 00:53:38.580

Chair Letha Tawney - Oregon PUC: Thanks, Zach.

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00:53:39.390 --> 00:53:45.920

Chair Letha Tawney - Oregon PUC: So, Cub is arguing that $1.3 million doesn't meet the

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00:53:46.170 --> 00:53:53.839

Chair Letha Tawney - Oregon PUC: And that, that, just for clarity, is the O&M part of the repair cost. Capital parts of the repair cost will be...

358

00:53:54.400 --> 00:53:59.249

Chair Letha Tawney - Oregon PUC: Adjudicated elsewhere in a different setting, but don't have the same...

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00:54:00.540 --> 00:54:05.889

Chair Letha Tawney - Oregon PUC: you have a future opportunity for cost recovery of those.

360

00:54:07.060 --> 00:54:22.209

Chair Letha Tawney - Oregon PUC: you know, Cub is arguing $1.3 million is... is simply not... doesn't... doesn't meet any kind of threshold for the company. Help me understand... I hear you... I hear you saying, well, we couldn't have baked it into base rates, but...

361

00:54:23.100 --> 00:54:29.590

Chair Letha Tawney - Oregon PUC: Why is it, sort of why is it large enough to warrant a deferral?

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00:54:29.880 --> 00:54:32.139

Chair Letha Tawney - Oregon PUC: Or is that not the way I should think about it?

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00:54:33.560 --> 00:54:43.219

Zach Kravitz (NW Natural): I guess I would step back a little bit and just consider the circumstances that brought us here. I mean, this is a situation where Northwest Natural

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00:54:43.420 --> 00:54:51.569

Zach Kravitz (NW Natural): prior to filing this application, we were not intending to incur any of these costs. In fact.

365

00:54:51.590 --> 00:55:08.489

Zach Kravitz (NW Natural): we were encouraging, the county to, make these repairs and, fund this pipeline. And ultimately, it got to a point, and, and, you know, Chair Sweet.

366

00:55:08.550 --> 00:55:19.909

Zach Kravitz (NW Natural): shared the situation in the county, it became clear that there was not the ability for the county to do that. And so.

367

00:55:20.750 --> 00:55:39.129

Zach Kravitz (NW Natural): Northwest Natural is here, not... not necessarily because this was our plan and what we wanted to do to become owners of this pipeline and incur this expense and make the required investments. It's here because we... we're here because, ultimately, our customers are at the end of that line, and we need to make it safe.

368

00:55:39.130 --> 00:55:48.820

Zach Kravitz (NW Natural): As part of that, you know, we are looking for, the Commission's support around the, the,

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00:55:48.820 --> 00:55:54.610

Zach Kravitz (NW Natural): the financial aspect of that commitment as well. And so, looking...

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00:55:54.750 --> 00:56:16.980

Zach Kravitz (NW Natural): I don't think necessarily that a materiality threshold is appropriate in this particular circumstance. I think it's really kind of the totality of the circumstance that really requires the... necessitates the approval of this acquisition, or excuse me, application.

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00:56:18.320 --> 00:56:19.150

Chair Letha Tawney - Oregon PUC: Thank you.

372

00:56:19.290 --> 00:56:21.760

Chair Letha Tawney - Oregon PUC: Any, any other questions for the company?

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00:56:26.120 --> 00:56:26.890

Chair Letha Tawney - Oregon PUC: No.

374

00:56:27.350 --> 00:56:28.130

Chair Letha Tawney - Oregon PUC: Okay.

375

00:56:30.140 --> 00:56:33.120

Chair Letha Tawney - Oregon PUC: Okay. I don't... I'm not rushing anyone. All right.

376

00:56:33.930 --> 00:56:37.079

Chair Letha Tawney - Oregon PUC: Thank you so much, Zach, I appreciate it.

377

00:56:38.410 --> 00:56:44.209

Chair Letha Tawney - Oregon PUC: I'd love to come back to Will, if I could, with a question.

378

00:56:44.700 --> 00:56:56.539

Chair Letha Tawney - Oregon PUC: And this might be a question for you, or you might want to punt it to, Council, but, you know, CUB is raising, sort of,

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00:56:56.590 --> 00:57:14.089

Chair Letha Tawney - Oregon PUC: the view that they see you creating a new standard, and that this isn't a big enough cost to justify a deferral. And I see the argumentation in the memo, but I wondered, you know, can you put a finer point on

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00:57:14.210 --> 00:57:23.000

Chair Letha Tawney - Oregon PUC: how... how you see this impacting the... the standard that the Commission has... has sought to utilize with deferrals?

381

00:57:24.970 --> 00:57:44.619

Will Wheeler - OPUC (he/him): Thank you, Chair Taney. I appreciate the question and the opportunity to... to offer a little bit of refinement. I can confidently say staff's intent is not to lower the standard for deferrals in any way. Staff really sees this particular situation as a very unique situation.

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00:57:45.000 --> 00:57:53.010

Will Wheeler - OPUC (he/him): And kind of the whole aspect of it means that, in this case, Staff thinks that

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00:57:53.500 --> 00:57:57.649

Will Wheeler - OPUC (he/him): it warrants a deferral. But I would, I would,

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00:57:58.040 --> 00:58:03.450

Will Wheeler - OPUC (he/him): I would pass it to Staff Counsel Stephanie Andrus if she wants to add anything on the more legal side.

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00:58:08.180 --> 00:58:20.799

Chair Letha Tawney - Oregon PUC: Stephanie, certainly as I've worked through deferrals over the years, you've been a vociferous advocate for relatively high bar, so I'm curious how you're thinking about this.

386

00:58:22.770 --> 00:58:23.759

Chair Letha Tawney - Oregon PUC: If you're there.

387

00:58:32.550 --> 00:58:34.240

Chair Letha Tawney - Oregon PUC: I don't see you on here.

388

00:58:35.230 --> 00:58:37.150

Chair Letha Tawney - Oregon PUC: Okay.

389

00:58:41.770 --> 00:58:43.430

Chair Letha Tawney - Oregon PUC: Alright, well...

390

00:58:45.350 --> 00:58:53.320

Chair Letha Tawney - Oregon PUC: DOJ, would someone else like to add anything to Will, or we'll just let Will's comments stand?

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00:58:56.850 --> 00:58:59.450

Chair Letha Tawney - Oregon PUC: Alright, we'll let Will's comments stand.

392

00:59:00.640 --> 00:59:08.599

Chair Letha Tawney - Oregon PUC: Stephanie often has challenges with her Zoom, so I'm gonna chalk it up to, Zoom has, failed her.

393

00:59:11.840 --> 00:59:24.820

Chair Letha Tawney - Oregon PUC: Or maybe failed all of DOJ. So, okay. Well, I think we have what we need in the memo. Certainly staff's argumentation is there. So I am curious, colleagues.

394

00:59:25.250 --> 00:59:31.639

Chair Letha Tawney - Oregon PUC: How you're thinking about the... the issue and the arguments before us.

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00:59:34.570 --> 00:59:35.980

Comm. Les Perkins - OPUC: I mean, I'll jump in.

396

00:59:36.210 --> 00:59:40.189

Comm. Les Perkins - OPUC: So I just want to recognize, how complex this issue is.

397

00:59:40.670 --> 00:59:44.400

Comm. Les Perkins - OPUC: In relation to the impact on the community and the pipeline it serves,

398

00:59:44.800 --> 01:00:02.640

Comm. Les Perkins - OPUC: or the community the pipeline serves. The total balance of energy available to serve the community, economic factors, state decarbonization goals, these are all factors, and they don't, necessarily nicely align. But what I keep in the front of my mind is that these are people in a community.

399

01:00:02.930 --> 01:00:14.479

Comm. Les Perkins - OPUC: That's struggling economically, has been struggling for some time, and it's very easy to say we need to shift to alternative energy options, but the reality is that this shift takes time and resources, and it doesn't happen overnight.

400

01:00:14.730 --> 01:00:21.020

Comm. Les Perkins - OPUC: So what we're doing today is allowing some time to address urgent safety issues. We're not allocating costs to any customer class.

401

01:00:21.200 --> 01:00:23.630

Comm. Les Perkins - OPUC: We're not determining prudence for the costs.

402

01:00:23.820 --> 01:00:30.469

Comm. Les Perkins - OPUC: We're giving time for a full record to be developed to allow us to make later determinations on if and how costs can be recovered by the company.

403

01:00:30.750 --> 01:00:44.570

Comm. Les Perkins - OPUC: So I appreciate Cub bringing up the need to be vigilant in how we use deferrals. I agree, we have to be vigilant. But I do find this to be a unique circumstance, and it should be seen as just that, just a unique situation.

404

01:00:44.910 --> 01:00:52.399

Comm. Les Perkins - OPUC: And in no way, precedent-setting. So I'm in support, I look forward to...

405

01:00:53.170 --> 01:01:04.340

Comm. Les Perkins - OPUC: This issue developing more fully, where we have better information to judge the prudence of decisions that are being made, and be able to have better information on

406

01:01:04.610 --> 01:01:18.779

Comm. Les Perkins - OPUC: how this fits into the state strategies. There's a lot to unpack, and I expect us to unpack that in later dockets. So, I would be in favor of the proposed commission motion.

407

01:01:23.550 --> 01:01:27.470

Comm. Karin Power - Oregon PUC (she/her): Chair Taney, I'll preface my... God...

408

01:01:28.390 --> 01:01:34.919

Comm. Karin Power - Oregon PUC (she/her): concerns with... I am also supportive of the staff memo recommendation for right now.

409

01:01:36.000 --> 01:01:39.549

Comm. Karin Power - Oregon PUC (she/her): I think this has been characterized to us.

410

01:01:39.700 --> 01:01:52.010

Comm. Karin Power - Oregon PUC (she/her): Up until I read some of the public comments just now, as a urgent safety landslide-driven issue.

411

01:01:52.540 --> 01:01:58.320

Comm. Karin Power - Oregon PUC (she/her): being addressed in this docket, but I note in some of the public comments submitted by

412

01:01:58.660 --> 01:02:02.420

Comm. Karin Power - Oregon PUC (she/her): For example, the City Administrator of the City of North Bend.

413

01:02:02.850 --> 01:02:09.550

Comm. Karin Power - Oregon PUC (she/her): There's a notation that they have exhausted O&M funds, or about to.

414

01:02:09.760 --> 01:02:20.440

Comm. Karin Power - Oregon PUC (she/her): And that there is... Quote... Roughly $2 million remaining for repairs, estimated at 5 to 6 times that amount.

415

01:02:21.390 --> 01:02:25.650

Comm. Karin Power - Oregon PUC (she/her): And I... Seriously question whether.

416

01:02:26.410 --> 01:02:34.390

Comm. Karin Power - Oregon PUC (she/her): Northwest Natural's rate base should absorb significant Ongoing structural issues.

417

01:02:34.560 --> 01:02:37.670

Comm. Karin Power - Oregon PUC (she/her): I think we heard a comment this morning about

418

01:02:37.810 --> 01:02:41.830

Comm. Karin Power - Oregon PUC (she/her): Some issues with subcontractor work, if I understood that correctly.

419

01:02:42.250 --> 01:02:45.049

Comm. Karin Power - Oregon PUC (she/her): And if there's larger issues with the pipeline.

420

01:02:47.850 --> 01:02:53.480

Comm. Karin Power - Oregon PUC (she/her): I, again, am very keen to see substantiation of those costs.

421

01:02:54.150 --> 01:02:57.539

Comm. Karin Power - Oregon PUC (she/her): In the actual proceeding where we determine prudency.

422

01:03:00.410 --> 01:03:02.480

Comm. Karin Power - Oregon PUC (she/her): It's a beautiful area of the state.

423

01:03:02.830 --> 01:03:06.960

Comm. Karin Power - Oregon PUC (she/her): I also love visiting it, and I deeply appreciated Bob Chenk's comments.

424

01:03:07.640 --> 01:03:09.780

Comm. Karin Power - Oregon PUC (she/her): But I...

425

01:03:16.880 --> 01:03:22.890

Comm. Karin Power - Oregon PUC (she/her): Have concerns about broader... Shareholder utilities stepping in to absorb.

426

01:03:24.210 --> 01:03:27.960

Comm. Karin Power - Oregon PUC (she/her): Locally owned infrastructure that they can no longer maintain on their own.

427

01:03:28.650 --> 01:03:31.650

Comm. Karin Power - Oregon PUC (she/her): And I understand this is a unique circumstance.

428

01:03:31.810 --> 01:03:33.960

Comm. Karin Power - Oregon PUC (she/her): But I think given the fiscal...

429

01:03:34.260 --> 01:03:37.460

Comm. Karin Power - Oregon PUC (she/her): Issues that many of our cities and counties are in.

430

01:03:38.710 --> 01:03:43.969

Comm. Karin Power - Oregon PUC (she/her): I am going to be taking a deep look at that prudency question.

431

01:03:45.240 --> 01:03:46.080

Comm. Karin Power - Oregon PUC (she/her): Thank you.

432

01:03:48.850 --> 01:04:00.390

Chair Letha Tawney - Oregon PUC: Thanks for that. I think, it is a challenge the way this issue crosses a wide range of dockets. We have capital costs and contensed cases. We've got O&M here.

433

01:04:00.980 --> 01:04:10.029

Chair Letha Tawney - Oregon PUC: the county has, O&M funds that come into the picture, there's... Unknowns about the landslide risk.

434

01:04:10.450 --> 01:04:20.469

Chair Letha Tawney - Oregon PUC: and there's a 20-year history of, as Bob pointed to, stipulations about how the distribution system will get paid for, and so on. So it's... it makes for quite the...

435

01:04:22.730 --> 01:04:28.989

Chair Letha Tawney - Oregon PUC: quite the... the knotted ball of, of, issues, I think.

436

01:04:29.140 --> 01:04:34.849

Chair Letha Tawney - Oregon PUC: That are, are really challenging from our, from our typical structured rate-making approach.

437

01:04:36.340 --> 01:04:44.050

Chair Letha Tawney - Oregon PUC: You know, the issue that's here before us right now is...

438

01:04:44.200 --> 01:04:47.440

Chair Letha Tawney - Oregon PUC: is a question of a deferral, and we...

439

01:04:48.270 --> 01:04:58.500

Chair Letha Tawney - Oregon PUC: Have really struggled with what is the standard for deferral, and really holding... holding to a standard, because there are so many

440

01:04:58.890 --> 01:05:01.680

Chair Letha Tawney - Oregon PUC: Unique circumstances that emerge.

441

01:05:02.280 --> 01:05:13.099

Chair Letha Tawney - Oregon PUC: And Cub is not wrong that, we typically see deferrals when it's an increased expense, and not when there's an increased savings out there to harvest for customers.

442

01:05:14.860 --> 01:05:24.389

Chair Letha Tawney - Oregon PUC: I am comfortable with the fact-specific nature of this, and that the, in particular, the cost allocation question remains open.

443

01:05:24.670 --> 01:05:25.670

Chair Letha Tawney - Oregon PUC: the...

444

01:05:25.820 --> 01:05:38.860

Chair Letha Tawney - Oregon PUC: When we come to an amortization decision, the earnings review and 3% test both help protect against over-recovery by the company. If the company can absorb.

445

01:05:39.000 --> 01:05:49.089

Chair Letha Tawney - Oregon PUC: These O&M costs, reasonably, those reviews both, help to ensure that that happens.

446

01:05:49.460 --> 01:06:02.680

Chair Letha Tawney - Oregon PUC: And I am not comfortable with an amortization that would place this on residential customers more broadly. I think that there is a really important role for industrial customers in Coos Bay.

447

01:06:02.850 --> 01:06:03.730

Chair Letha Tawney - Oregon PUC: to play.

448

01:06:04.550 --> 01:06:08.020

Chair Letha Tawney - Oregon PUC: That needs to be, addressed.

449

01:06:09.100 --> 01:06:15.370

Chair Letha Tawney - Oregon PUC: But I don't think we're deciding any of that here.

450

01:06:15.560 --> 01:06:27.710

Chair Letha Tawney - Oregon PUC: And I think how we think about deferrals is in the midst of a really enormous, both, challenge from the capital expansion, the climate mitigation and adaptation.

451

01:06:27.830 --> 01:06:38.570

Chair Letha Tawney - Oregon PUC: is sort of... well, not capital for deferrals, but the O&M impact of climate adaptation and mitigation is layering on customer bills.

452

01:06:39.070 --> 01:06:51.039

Chair Letha Tawney - Oregon PUC: And on the... as we try to reform or move into multi-year rate making, how we think about deferrals is under, really significant pressure.

453

01:06:51.770 --> 01:07:05.819

Chair Letha Tawney - Oregon PUC: And I appreciate Cub's principal perspective on how we navigate that, so that they are used in a balanced manner, and not always only to benefit the company.

454

01:07:06.590 --> 01:07:12.279

Chair Letha Tawney - Oregon PUC: But here, to Commissioner Perkins' point.

455

01:07:12.490 --> 01:07:20.480

Chair Letha Tawney - Oregon PUC: We have a relatively unique issue with, Economically challenged community.

456

01:07:21.240 --> 01:07:33.740

Chair Letha Tawney - Oregon PUC: And, oh, I see this primarily as a route for the community to finance the infrastructure that they cannot access currently through their own bonding authority.

457

01:07:34.230 --> 01:07:35.900

Chair Letha Tawney - Oregon PUC: And...

458

01:07:36.170 --> 01:07:45.450

Chair Letha Tawney - Oregon PUC: Until we navigate our way through this, that's... that's my perspective, is this is a financing mechanism, fundamentally, for the community.

459

01:07:46.260 --> 01:07:50.830

Chair Letha Tawney - Oregon PUC: And we'll deal with how that might play out in the cost allocation questions.

460

01:07:51.430 --> 01:07:55.250

Chair Letha Tawney - Oregon PUC: I... I...

461

01:07:55.860 --> 01:08:04.579

Chair Letha Tawney - Oregon PUC: I think that commenters have raised a host of complex questions about what the pathway to decarbonization looks like.

462

01:08:04.720 --> 01:08:07.449

Chair Letha Tawney - Oregon PUC: And I am worried that...

463

01:08:07.730 --> 01:08:25.489

Chair Letha Tawney - Oregon PUC: the cost of the natural gas commodity fuel under the CPP will really become a burden to Coos County, industrial customers, and that there really needs to be some serious conversation in that community about what

464

01:08:25.700 --> 01:08:32.899

Chair Letha Tawney - Oregon PUC: natural gas costs that are more like $13 an MMBTU instead of $4 really means.

465

01:08:33.149 --> 01:08:42.140

Chair Letha Tawney - Oregon PUC: It may be that they need to think about how to wean off more generally, given the decarb trajectory, but that's not the question before us today.

466

01:08:44.000 --> 01:09:03.179

Chair Letha Tawney - Oregon PUC: So, I am comfortable taking this step, knowing we're looking at this in a wide range of other places, and this is primarily a financing mechanism

for the community as we think about how to manage through their ability to retain their economic base for the moment.

467

01:09:03.850 --> 01:09:07.340

Chair Letha Tawney - Oregon PUC: Recognizing there's some future challenges coming to that base.

468

01:09:07.479 --> 01:09:10.209

Chair Letha Tawney - Oregon PUC: As... as natural gas is decarbonized.

469

01:09:10.460 --> 01:09:18.079

Chair Letha Tawney - Oregon PUC: So, I'll move we adopt staff's motion as proposed, and look for a second.

470

01:09:19.109 --> 01:09:38.819

Comm. Les Perkins - OPUC: I will second, and just, one more brief comment. Please. I'll just say, having been in county government for 24 years, having been through the economic struggles of trying to figure out how to fund services for a community and being out of... counties that find themselves in a place

471

01:09:38.969 --> 01:09:45.539

Comm. Les Perkins - OPUC: of needing to pay for things, but not having the mechanisms to do it. And so, I appreciate your comments, Chair Taney.

472

01:09:45.739 --> 01:09:54.259

Comm. Les Perkins - OPUC: about... this is also just a funding mechanism, and and I appreciate your comments to, Commissioner Power, about...

473

01:09:54.639 --> 01:10:06.279

Comm. Les Perkins - OPUC: how much we have to weigh the needs of a specific community with the needs of the total system. So, not an easy issue, very complicated, but also, I think, quite unique.

474

01:10:10.810 --> 01:10:11.870

Comm. Karin Power - Oregon PUC (she/her): And I'll concur.

475

01:10:13.420 --> 01:10:24.510

Chair Letha Tawney - Oregon PUC: Well, the motion is adopted, and we'll look forward to continuing to engage this issue, both in its specifics and its more broad implications.

476

01:10:24.890 --> 01:10:30.400

Chair Letha Tawney - Oregon PUC: Let me see if there's anything further to come before us this morning.

477

01:10:31.660 --> 01:10:33.160

Chair Letha Tawney - Oregon PUC: I'm seeing nothing.

478

01:10:33.410 --> 01:10:35.800

Chair Letha Tawney - Oregon PUC: We are adjourned. Thank you all.

UG 152

ORIGINAL

PUBLIC UTILITY COMMISSION OF OREGON

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Administrative Hearings Division

UG 152

STAFF TESTIMONY

OF

BONNIE B. TATOM

In the Matter of Northwest Natural Gas Company's Application for a General Rate Revision

Coos County

March 7, 2003

DOCKETED

CASE: UG 152
WITNESS: Bonnie B. Tatom

PUBLIC UTILITY COMMISSION OF OREGON

RECEIVED
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Public Utility Commission of Oregon
Administrative Hearings Division

STAFF EXHIBIT 100

Direct Testimony on Coos County

DOCKETED

March 7, 2003

Staff/100
Tatom/1

Q. PLEASE STATE YOUR NAME, YOUR POSITION AT THE PUC, BUSINESS ADDRESS AND BUSINESS TELEPHONE NUMBERS.

A. My name is Bonnie B. Tatom. I am employed as the Program Manager for the Natural Gas Rates & Planning Section of the Electric & Natural Gas Division, Public Utility Commission of Oregon (OPUC or Commission). My telephone number is (503) 378-8225. My qualifications are listed in Exhibit Staff/101, Tatom/1.

Q. WHAT WAS YOUR ASSIGNMENT IN THIS PROCEEDING?

A. My assignment in this proceeding covers the policy issues in the bifurcated UG 152 docket regarding Northwest Natural Gas Company's (NW Natural or company) filing seeking a Commission order allowing rolled-in rate recovery for its costs in developing a distribution system in Coos County.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into four major areas: (1) Staff's summary recommendation(s); (2) a brief history of the Commission's involvement in the company's current effort to bring natural gas service to Coos County; (3) Staff's position on the company's rate proposal with specific discussion on use of the company's main extension policy as a method of determining the contribution customers should make in the Coos County investment and the rate impact of the company's rate proposal, and finally, (4) discussion of an alternative to Staff's position the Commission might consider.

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Summary Recommendations

Q. WHAT ARE YOUR SUMMARY RECOMMENDATIONS REGARDING NW NATURAL'S FILING SEEKING AN ORDER FROM THE COMMISSION?

A. Staff recommends the Commission deny the company's request for rolled-in rate treatment of the initial distribution system (defined beginning on page 8 of the company's direct testimony, UG 152/NWN/1500, Henderson) because the proposal is not prudent under the company's main extension policy. However, Staff's alternative proposal, discussed later in this testimony, provides circumstances under which the Commission could approve rolled-in rate treatment. If the Commission approves the company's proposal or Staff's alternative, then Staff recommends the Commission approve the company's cost recovery proposals for the cost of transportation on the Coos County pipeline, i.e., the per-therm surcharge on all gas sales in Coos County and the collection of any balance of transportation costs not collected from the Coos County surcharge from all other customers in conjunction with the Purchased Gas Adjustment (PGA) mechanism. These recommendations are explored in depth later in this testimony.

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Staff/100
Tatom/3

Brief History of the Commission's Involvement in Bringing Natural Gas to Coos County

Q. BRIEFLY, WHAT HAS TRANSPIRED TO DATE TO BRING NATURAL GAS SERVICE TO THE SOUTH COAST AREA?

A. As NW Natural indicates in its testimony, the company has attempted to bring natural gas to the South Coast region of the state since the mid 1960's under a number of regulatory schemes with the cooperation of varying numbers of potential industrial customers. The most recent (and current) proposal has been under consideration since the late 1990's and involves the building of a pipeline connecting Williams Pipeline with the South Coast by Coos County, and the nearly simultaneous building of a distribution system to serve communities in the region by NW Natural.

Q. HAS THE COMMISSION BEEN INVOLVED IN THE COMPANY'S PURSUIT TO SERVE COOS COUNTY COMMUNITIES?

A. Yes, the Commission has weighed in on three separate, but interrelated dockets since 1999. The first was UA 76, which ultimately resulted in the exclusive allocation of service territory in Coos County [1] to NW Natural so that the company could construct a distribution system to extend service from the proposed County pipeline to the communities of Coos Bay, North Bend, Coquille and Myrtle Point.

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[1] With the exception of the City of Bandon, which chose to leave open the option of ultimately providing natural gas service to its citizens as a municipal utility.

Staff/100
Tatom/4

Q. BRIEFLY DESCRIBE THE OTHER TWO DOCKETS IN WHICH THE COMMISSION HAS BEEN INVOLVED.

A. Docket UA 93 was the company's application to allow Coos County to serve customers directly in some cases. DR 30 was the company's request for a declaratory ruling to allow the investment in the distribution system to be rolled-in to the rates of all NW Natural customers.

Q. WHAT WERE THE COMMISSION'S RULINGS IN THESE TWO DOCKETS?

A. In Order No. 02-678, entered October 4, 2002, the Commission denied the company's application in UA 93, citing the lack of authority to allocate customers rather than territory. NW Natural has since proposed legislation, introduced as SB 321, which if signed into law, will allow the Commission to approve a contract authorizing Coos County to serve certain customers in the service territory allocated to NW Natural. In Order No. 02-863, entered December 11, 2002, the Commission closed Docket DR 30 without issuing a final decision on the merits, citing the fact that the issues in the request for the declaratory ruling had been subsumed in the general rate case filed by the company on November 29, 2002.

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Staff's Positions

Use of Main Extension Policy

Q. HOW WOULD NW NATURAL TYPICALLY DETERMINE WHETHER OR NOT TO EXTEND SERVICE TO NEW CUSTOMERS?

A. In its response to DR #288,[2] the company states that it would "not extend service to a new community if projected loads and costs result in an expectation of an uneconomic investment." This analysis of the projected loads and costs is done using the company's main extension policy, embodied in Schedule X.[3] Schedule X is the vehicle for determining whether or not extending service to new customers is prudent, i.e., if the anticipated margins from committed and expected customers, along with applicable customer contributions, provides an internal rate of return at or above the company's allowed rate of return.

Q. EXPLAIN HOW SCHEDULE X WORKS.

A. A main extension is the piping and associated facilities required to extend service from the company's existing main facilities into an area not previously supplied to serve an applicant.[4] Schedule X states how the construction allowance is determined for applicants and therefore, what construction contribution will be required to serve the applicant. If the allowance is greater than the cost of construction, the installation is performed at no charge to the applicant. If the cost of construction is greater than the

[2] See Exhibit Staff/102, Tatom/1.
[3] See Exhibit Staff/102, Tatom/2-7.
[4] See NW Natural's Tariff, General Rules and Regulations, Sheet 00.5

construction allowance, the applicant must pay a construction contribution equal to the difference between the cost of construction and the construction allowance. In some cases, the company may perform an Infill/Exfill Potential Analysis" in addition to an analysis under Schedule X. An infill/exfill analysis gives economic and financial consideration to the potential for customer growth along or beyond the main extension to the applicant.

Q. IN DOCKET DR 30, STAFF PROPOSED THAT THE COMMISSION USE SCHEDULE X AS A MEANS TO DETERMINE UNDER WHAT TERMS NW NATURAL SHOULD EXTEND SERVICE TO COOS COUNTY. WHAT WERE THE IMPLICATIONS OF STAFF'S DR 30 PROPOSAL?

A. Under even a conservative approach using Schedule X, Coos County customers would have to pay a construction contribution of roughly $6.1 million [5] for the investment to serve the communities with the initial distribution system.

Q. HAS STAFF CHANGED ITS VIEW ON THE USE OF SCHEDULE X IN THIS CASE?

A. No. Staff believes it is an appropriate way of evaluating the construction contribution expected from Coos County customers. After determining the

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[5] $12 million investment less (5 * 1,184,936) or $6,075,320, where $1,184,936 is the 5-year Coos County annualized margin revenue (from Exhibit 3 of the DR 30 Stipulation filed April 18, 2002), using 5 times annualized margin revenue as a proxy for the amount allowed by the company's Schedule X in determining the construction allowance.

County's construction allowance, the Coos County customers should pay the construction contribution to be served. Using the main extension policy, as Staff has recommended, requires a construction contribution from Coos County customers in order for NW Natural's investment in Coos County to be a prudent one. Staff believes that although this contribution is generally expected prior to commencement of construction, NW Natural could make an exception to its requirement of advance payment for good cause.[6]

Q. NW NATURAL ASSERTS THAT USING SCHEDULE X TO DETERMINE THE CONSTRUCTION CONTRIBUTION IS NOT APPROPRIATE IN COOS COUNTY. WHY NOT?

A. NW Natural believes that Coos County customers would be unwilling to make the greater than $5 million construction contribution and that because Coos County citizens are already contributing to the transmission pipeline through their property taxes, a greater contribution required by the main extension policy would significantly discourage customer connections. Further, the company believes that because the extension of service to Coos County is dissimilar from extension of service contemplated by Schedule X, using Schedule X is not appropriate.

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[6] NW Natural's Tariff allows for such exceptions to advance payment specifically for manufactured housing developments, mobile home developments or houseboat moorage developments. See Schedule X, Sheet X-4.

Staff/100
Tatom/8

Q. HAS THE COMPANY USED SCHEDULE X IN THE PAST TO DETERMINE WHETHER OR NOT AN EXTENSION OF SERVICE TO A NEW COMMUNITY IS APPROPRIATE?

A. Yes. In response to DR #289, the company included an example of such a request to extend service to the community of Gates, Oregon. In that case from 1997, the company said it was not economically sound to extend service to Gates due to the large amount of aid in construction contribution that would be expected of the person(s) requesting natural gas service, and the low potential for future growth in the community. See Exhibit Staff/102, Tatom/8-11. In addition, the company also noted "[o]ften, it is the community that makes the election not to extend service based on the company's required contribution-in-aid-of construction." The company has also evaluated extending service to the City of Monroe and the City of Vernonia. Of these, the company serves only Vernonia.

Q. DO OTHER LOCAL DISTRIBUTION COMPANIES REGULATED BY THE COMMISSION USE THEIR MAIN EXTENSION POLICIES TO DETERMINE WHETHER OR NOT TO EXTEND SERVICE TO UNSERVED COMMUNITIES?

A. Yes. Both Avista Utilities and Cascade Natural Gas Corporation use their respective main extension policies to make such a determination. See Exhibit Staff/102, Tatom/12-15 for these LDCs' responses to Staff's information request regarding the LDCs' extension of service to new communities.

Q. IS STAFF CONCERNED BY THE COMPANY'S PROPOSAL IN UG 152 TO SERVE COOS COUNTY IN SPITE OF THE RESULTS OF THE SCHEDULE X IMPLICATIONS?

A. Yes. Staff believes that not using the company's long-standing main extension policy embodied in Schedule X could lead to additional requests for natural gas service by unserved communities. Staff is concerned that ignoring the main extension policy sets a precedent for future extensions to unserved communities that would result in rates for all customers in the future that would not be fair or reasonable, i.e., a number of rate increases, each of which by itself was "not an unreasonable burden," [7] for extensions to unserved communities could very well add up to unfair and unreasonable exactions from customers.

Q. ARE THERE MANY INCORPORATED COMMUNITIES IN NW NATURAL'S SERVICE TERRITORY THAT ARE CURRENTLY NOT SERVED BY NATURAL GAS?

A. Yes. In response to DR #287 (see Exhibit Staff/102, Tatom/16-17), NW Natural listed 24 communities in its service territory (other than the South Coast area) that are not currently served by natural gas. In addition, the company listed 10 communities in its service territory in Coos, Lane and Douglas Counties that are not currently served by natural gas. It's impossible to predict which, if any, of these communities would ask NW Natural

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[7] See Exhibit UG 152/NWN/1500, Henderson/15, line 19.

to ignore its tariffed Schedule X (as the company proposes with the construction of the distribution system in Coos County).

Q. HAS NW NATURAL PROPOSED A DIFFERENT RATEMAKING SCHEME TO SERVE THESE OTHER UNSERVED COMMUNITIES IN THE EVENT ONE OR MORE REQUESTS SERVICE?

A. Yes. In general, the company indicates that it will use its main extension policy to determine whether or not it should extend service to new communities. The company has stated that the extension of service to Coos County is unique and that only those unique circumstances warrant a departure from its main extension policy.

Rate Impact Issues

Q. HAS THE COMPANY EVALUATED THE RATE IMPACT OF ITS PROPOSAL TO ROLL IN RATES TO ITS ENTIRE CUSTOMER BASE RATHER THAN JUST THOSE POTENTIAL CUSTOMERS IN COOS COUNTY?

A. Yes. In its request for a declaratory ruling last year, the company included several exhibits that illustrated a range of possible rate impacts of its rolled-in rate proposal when applied to all customers, not merely the smaller-load customers as the UG 152 filing proposes. The UG 152 proposal would apply the entire increase in revenue requirement to Schedules 1, 2, and 3 with a rate impact of $0.00283 per therm.

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Staff/100
Tatom/11

Q. ACCORDING TO THE DR 30 EXHIBITS, WHAT IS THE RANGE OF POSSIBLE IMPACTS ON RATES IF THE COMMISSION WERE TO APPROVE ROLLED-IN RATE TREATMENT FOR THE COMPANY'S COOS COUNTY INVESTMENT ACROSS ALL CUSTOMERS?

A. Under the company's proposal in DR 30, depending on the assumptions for participation by industrial customers, the range of rate impacts is from $0.00053 per therm (about $0.03 per month for a typical residential customer using 54.1 therms per month) with an estimated Coos County industrial load of 19,836,000 therms (in the first five years) to approximately $0.00110 per therm for the same residential customer with a considerably smaller estimated Coos County industrial load of 240,000 therms (again, just over the first five years). Exhibits Staff/102, Tatom/18-19 demonstrate in graphical form the load growth forecasted by the company over a 30-year period (Tatom/18) and the company's projected revenues and revenue requirement over the same time period (Tatom/19). These graphs demonstrate several points: (1) the critical nature of the company's load projections, especially with regard to industrial sector participation, (2) the relative stability of the expected residential and commercial load, and (3) the shortfall of revenues even over a thirty-year period.

Q. BRIEFLY DISCUSS ANY CAVEATS THE COMMISSION SHOULD CONSIDER WHEN EXAMINING THE ROBUSTNESS OF THIS RANGE OF POSSIBLE RESULTS.

A. The biggest concern to Staff regarding these estimates is that the company has assumed a sizeable load associated with the inclusion of several large industrial customers in the area, which results in the lower rate impact the company adopts in its testimony. Participation by these customers is dependent on far too many factors to rely on this growth. For example, these customers would have to convert to natural gas from other energy sources and more importantly, the proximity of the Coos County pipeline certainly is an invitation to bypass NW Natural's distribution system in favor of taking service directly from the County. The Commission should consider the potential impact of industrial bypass on the remaining residential and other smaller load customers who would have to bear the burden of the investment, along with all of the company's other customers throughout its service territory. In its testimony, the company suggests the severity of the risk of industrial bypass in Coos County does depend on the extent to which high-volume commercial and industrial gas users, defined as "Eligible Customers" in the Transportation Service Agreement between the County and NW Natural, locate in Coos County.[8]

Q. IS THE RATE IMPACT UNDER THE COMPANY'S PROPOSAL JUST AND REASONABLE?

A. If the load projections actually materialize over the course of the company's analysis, then the rate impact is not burdensome. Under the company's proposal, if the load projections are too optimistic, other NW Natu-

[8] See Staff/102, Tatom/20.

ral customers could pay even more than currently forecasted. While charging its smaller-load customers $0.003 a therm may not be unreasonable, a greater charge may be. However, the reverse is also true. If the load projections are actually conservative as the company suggests in its testimony,[9] then the rate impact could be less than the company's or Staff's estimates.

Q. OVER WHAT PERIOD OF TIME HAS THE COMPANY EVALUATED ITS INVESTMENT IN COOS COUNTY?

A. The company evaluated its investment over thirty years.

Q. IN THAT TIME, DOES THE INVESTMENT BECOME COST-EFFECTIVE, i.e., ARE CUSTOMERS INDIFFERENT TO THE INVESTMENT?

A. No, customers are not indifferent to the company's investment under its current ratemaking proposal until nearly fifty years have passed.[10]

Q. NOTWITHSTANDING THE OVERALL RATE IMPACTS, IS THE PROPOSED RATE SPREAD OF THIS INVESTMENT APPROPRIATE?

A. No. Staff believes that the company's proposal in UG 152 to spread the entire requested increases only to residential and smaller load commercial customers on Schedules 1, 2 and 3 is entirely inappropriate. The company's proposal does not spread the cost of the distribution system to industrial customers.

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[9] See Exhibit UG 152/NWN/1500, Henderson/8, lines 6-8.
[10] In response to DR #292, the company stated that the investment is cost-effective over a 49-year period.

Q. WHY IS THIS PROPOSAL INAPPROPRIATE?

A. The company's proposed investment in Coos County is clearly designed to promote economic growth in the county by, as HB 2153 [11] proposed, attracting "significant *industries* to locate in the area, thereby increasing opportunities for employment and additional economic activities that will be generated as a result of such industries." [Emphasis added]. In addition, the company's analysis of load potential in Coos County is heavily influenced by the amount of industrial load expected to be served by natural gas.

Q. WHAT IS STAFF'S PROPOSAL FOR SPREADING THE REVENUE REQUIREMENT THAT MAY RESULT FROM THE COMPANY'S INVESTMENT IN THE INITIAL DISTRIBUTION SYSTEM?

A. Staff believes that the ultimate revenue requirement, for the Coos County investment, allowed in rates at October 1, 2003 (or at the time of the Commission's order in UG 152), should be spread on an equal percentage of margin basis across all rate classes. This rate spread treatment equitably shares the cost of the investment between all customer classes, including industrial customers for whom the 1999 Legislature determined a natural gas pipeline was necessary.

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[11] HB 2153 was signed into law in July 1999, and provided for $20 million in lottery bonds to Coos County to cover part of the cost of a natural gas transmission pipeline to the coast.

Does Economic Development Play a Role in the Commission's Mission?

Q. HAS NW NATURAL SOUGHT ROLLED-IN RATE TREATMENT ON THE GROUND THAT THE COOS COUNTY DISTRIBUTION SYSTEM WILL PROMOTE ECONOMIC DEVELOPMENT?

A. According to the company's testimony, the Commission should review the company's proposal for rolled-in rate treatment as a separate issue from the legislature's motivation in partially funding the County's transmission pipeline. However, the company continues to make references to "economic development" as a reason to bring natural gas to the region's potential customers. For example, in UG 152/NWN/100, DeBolt/14, the company makes it clear that "natural gas service has long been a goal for the Coos Bay area as a matter of *state economic development policy*." [Emphasis added].

Q. DOES THE COMMISSION'S AUTHORITY EXTEND TO ENCOURAGING, THROUGH ITS RATEMAKING PROCESS, ECONOMIC DEVELOPMENT?

A. The legislature has given the Commission broad authority to do all things necessary to supervise and regulate public utilities. However, the statutory scheme under which the Commission operates does not suggest that the Commission's authority extends to setting rates to encourage economic development.[12] While NW Natural might interpret the law to

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[12] In ORS 756.040, the Commission is authorized to make use of the jurisdiction and powers of the office to protect customers of public utilities, and the public generally, from unjust and unreasonable exactions and practices and to obtain for them adequate service at fair and reasonable rates.

require the Commission to obtain service for customers, the second part of the phrasing is "at fair and reasonable rates," not "at rates designed to encourage economic development." NW Natural has proposed rolled-in ratemaking treatment specifically because the company does not expect to earn its rate of return or enjoy profitable growth in the County without sharing the costs of the distribution system among its entire customer base, i.e., with Coos County rates higher than those proposed by the company, the economic development will not occur.

Alternative Proposal

Q. SHOULD THE COMMISSION EXAMINE A DEPARTURE FROM STAFF'S RECOMMENDED PROPOSAL THAT THE COMPANY USE ITS MAIN EXTENSION POLICY TO DETERMINE THE APPROPRIATE CUSTOMER CONTRIBUTION FOR THE INVESTMENT IN COOS COUNTY?

A. Yes. NW Natural, in its response to DR #296, stated that the investment in Coos County "is a prudent one because of the unique circumstances presented by this investment." The company further states that the investment is also financially prudent because only $12 million (for the distribution system) is to be supported by NW Natural's customers throughout its service territory, while the remainder of the total investment, including the County's transmission pipeline, of roughly $50 is to be borne by Coos County taxpayers.

NW Natural is correct that the circumstances underlying its proposal are unique. The County is willing to make a huge investment to build a transmission pipeline to the coast and there is potential for economic growth, which may result in optimistic customer growth. Although Schedule X sets out what is prudent in terms of the effect on other customers, the Commission could allow the company a longer recovery or payback period (the 49-year analysis) than generally permitted. In addition, the Commission could conclude the company need not adhere to its main extension policy given the expected small rate impact of rolling in the costs of the distribution pipeline to non-Coos County customers and the other unique circumstances in Coos County.

Q. DOES STAFF HAVE AN ALTERNATIVE TO ITS RECOMMENDATION THAT THE COMMISSION NOT ALLOW ROLLED-IN RATE TREATMENT IN THE MANNER PROPOSED BY NW NATURAL?

A. Yes. Staff proposes an alternative under which we could support rolled-in rate treatment of the costs associated with the initial distribution system.

Q. WHAT IS STAFF'S ALTERNATIVE PROPOSAL?

A. Staff proposes that NW Natural's shareholders take additional risk in the extension of service to Coos County. As the company states in its testimony, Coos County customers are already paying for the transmission pipeline so "requiring a greater contribution from citizens in Coos County would significantly discourage customer connections and defeat the pur-

pose in developing a distribution system in that area." [13] NW Natural then proposes that its smaller-load customers pay for the distribution system with a "very small" [14] charge of $0.00283 per therm. The only other "partner" in this venture--NW Natural—isn't assuming any risk, other than the typical risk all utilities have that costs and revenues will be different from what is used to set rates. Looked at another way, under the company's proposal, Coos County citizens pay for the transmission pipeline—roughly $27 million, NW Natural's Coos County customers pay for the transportation charges on the pipeline—approximately $200,000 per year, NW Natural's customers pay for any balance of the transportation charges and the rolled-in rate effect of the $12 million investment, while NW Natural has only the risk of regulatory lag, which the company can influence to some extent by the filing of another rate proposal.

Q. HOW WOULD STAFF'S PROPOSAL WORK?

A. Under NW Natural's proposal, with the exception of the surcharge to Coos County customers, all residential and smaller load commercial customers will pay for the prudently-incurred costs of the initial distribution system over a long period of time. Of course, there is some risk to NW Natural were the Commission to disallow any of the expected $12 million investment. Beyond that risk, NW Natural's shareholders are not at risk in the development of the distribution system in Coos County. Staff proposes

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[13] See Exhibit UG 152/NWN/1500, Henderson/14, lines 7-9.
[14] See Exhibit UG 152/NEW/1500, Henderson/10, line 6.

that the Commission only allow 90% of the prudently incurred investment in rates, i.e., that the company's shareholders assume 10% of the initial investment found to be prudent. If the prudently-incurred initial investment were $12 million, then only a maximum of $10.8 million would be spread to NW Natural's customers. Under Staff's proposal, Coos County citizens will still pay for the $27 million transmission pipeline, NW Natural's Coos County customers still pay for the $200,000 per year transportation charges on the pipeline, NW Natural's customers pay for any balance of the transportation charges and the rolled-in rate effect of, for example, the $10.8 million investment, and NW Natural still maintains the risk of revenue variances (up or down) in Coos County and pays the balance of the initial investment of, in Staff's example, only $1.2 million, less than 2% of the total outlay for "economic development" in Coos County.

Q. WHAT RATE TREATMENT WOULD STAFF SUPPORT UNDER ITS ALTERNATIVE PROPOSAL?

A. Under this alternative, Staff would support rolled-in rate treatment for the initial distribution system, up to $10.8 million, recognizing that only that portion of the prudently-incurred costs for facilities in service on October 1, 2003, may appropriately be applied to all customers' rates.

Q. WHAT IS THE GENERAL RATE EFFECT OF STAFF'S ALTERNATIVE PROPOSAL?

A. Under Staff's alternative proposal, because the revenue requirement is less than the company's proposal, the overall rate impact would also be

less than $0.00283 per therm. In addition, all customer classes would see some small impact, not just the Schedule 1, 2 and 3 customers.

Q. IS THERE ANY PRECEDENT TO CONSIDER IN TAKING THIS APPROACH?

A. Yes. The Commission has ruled in at least three electric utility dockets that not all prudently-incurred power costs must be allowed in rates.[15]

Q. ARE THERE ADDITIONAL COSTS OF PROVIDING GAS SERVICE TO COOS COUNTY NOT INCLUDED IN THE COMPANY'S INITIAL CONSTRUCTION COSTS THAT NW NATURAL HAS PROPOSED TO RECOVER?

A. Yes. NW Natural has also proposed a surcharge on Coos County customers to pay the pipeline transportation charges.

Q. WHAT IS THE COMPANY'S PROPOSAL?

A. As the company indicates in its testimony, it proposes a $0.01 per therm surcharge on Coos County customers across all sales rate schedules.

Q. WILL THIS SURCHARGE PAY THE TRANSPORTATION CHARGE IN ITS ENTIRETY?

A. Not likely in the very near term. However, the company does expect that as load increases in Coos County, the one-penny surcharge will cover

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[15] In UE 116, the Commission approved a stipulation allowing only 83% of PacifiCorp's prudently-incurred power costs over approximately a nine-month period to be recovered in rates. In UE 115, the Commission allowed a sharing mechanism whereby PGE and its customers shared the difference between an amount in rates and actual power costs. In addition, the Commission approved various mechanisms for sharing excess power costs for all three IOUs in 2001.

transportation charges. Until that time, NW Natural proposes that any balance of transportation charges remaining after the surcharge to Coos County customers be collected from all applicable NW Natural customers in Oregon in conjunction with the PGA mechanism (much like upstream pipeline demand charges).

Q. WHAT IS STAFF'S RECOMMENDATION WITH REGARD TO THE COMPANY'S SURCHARGE PROPOSALS?

A. Staff agrees with the company's surcharge proposals. Staff believes that the collection of a $0.01 per therm charge on Coos County customers' bills to pay for the pipeline charges is not arbitrary; it represents the company's cost of transportation on the Coos County pipeline. In addition, Staff agrees that any remainder of the pipeline charges be assessed on the bills of all NW Natural customers through the PGA mechanism. The rate effect on all customers is extremely small—about $0.00031 per therm.

Q. HAS NW NATURAL SUGGESTED IT WOULD NOT BUILD THE DISTRIBUTION SYSTEM UNDER STAFF'S RECOMMENDED PROPOSAL THAT USES THE COMPANY'S MAIN EXTENSION POLICY?

A. Yes. In its testimony, the company stated that it would not proceed with construction if Staff's main extension policy scenario were accepted by the

Commission. Under that scenario, only $6.4 [16] million would be allowed-into rates. The company has not indicated whether or not any alternative proposal would be acceptable.

Q. HAS THE COMPANY COMMITTED TO BUILDING THE DISTRIBUTION SYSTEM WITH A FAVORABLE ORDER IN THIS DOCKET?

A. Yes. NW Natural signed an agreement with Coos County on July 30, 2001 that requires the company to complete the initial phase of the distribution system "so that it is operational no later than 30 days following completion of the" Coos County pipeline. To that end, it appears that NW Natural has only "a couple of items to clear up with the PUC"[17] before *Pipeline Solutions*, the contractors for the Coos County transmission pipeline starts construction on April 15, 2003.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

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[16] The company's testimony indicated that using an approximate ratio of 60/40 as the split between NW Natural and Coos County customers for the $12 million proposed investment, that only $7.2 million would be allowed to be recovered in rates. Using a more accurate ratio of 54/46 means that Staff's use of the company's Commission-approved main extension policy would allow only $6.4 million of the company's $12 million proposed investment.

[17] See Exhibit Staff/102, Tatom/21, a newspaper article in the Valley Sentinel (Coquille), quoting Steve Shute, the Project Coordinator.

CASE: UG 152
WITNESS: Bonnie B. Tatom

PUBLIC UTILITY COMMISSION OF OREGON

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Administrative Hearings Division

STAFF EXHIBIT 101

Witness Qualification Statement

March 7, 2003

DOCKETED

Staff/101
Tatom/1

WITNESS QUALIFICATIONS STATEMENT

NAME: Bonnie B. Tatom

EMPLOYER: Public Utility Commission Of Oregon

TITLE: Program Manager

ADDRESS: 550 Capitol St NE, Suite 215, Salem, OR 97301-2551

EDUCATION: Bachelor of Arts degree in Economics from Washington State University (1978).

National Association of Regulatory Utility Commissioners' (NARUC) Annual Regulatory Studies Program administered by the Michigan State University Graduate School of Business Administration (1990). NARUC Western Utility Rate School administered by Florida State University (1995).

RELEVANT WORK EXPERIENCE: *Program Manager* for the Natural Gas Rates & Planning Section, Electric and Natural Gas Division, Utility Program, Public Utility Commission of Oregon (OPUC) since March 1999. From September 1994 to March 1999 I was primarily responsible for the analysis of natural gas utility least-cost plans, energy utility tariff filings, and demand-side resource activities. Prepared staff recommendations in UE 94 and PGE's Rate Plan (1996) regarding appropriate CIS, wage & salary, memberships, dues & donations, and customer account expenses. Prepared testimony in UE 102 regarding workforce and consumer protection issues, including certification of energy service suppliers and environmental disclosure. Prepared testimony in UG 132 (NW Natural) regarding memberships, dues and donations, miscellaneous operating revenues, and workforce. Prepared staff recommendations in UE 115 and UE 116 (2001) regarding wages & salaries, memberships, dues & donations, miscellaneous A & G expenses, materials & supplies, SERP, bonuses, and overtime. Prepared testimony in UG 143, NW Natural's request for a decoupling mechanism.

Public Utility Analyst with the Electric and Natural Gas Division of the OPUC from May 1990 through August 1994. Responsibilities included review of natural gas utility integrated resource plans, energy utility tariff filings, and participation in Commission rulemaking proceedings.

CASE: UG 152
WITNESS: Bonnie B. Tatom

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Administrative Hearings Division

STAFF EXHIBIT 102

Exhibits in Support of Staff's Direct Testimony in Exhibit 100

March 7, 2003

DOCKETED

NW Natural

Rates & Regulatory Affairs

Company Response to UG 152 Staff Requests

January 27, 2003

288. In general, why would NW Natural not extend service to a new community?

Response:

The term "new community" is assumed to mean a city or town within NW Natural's exclusive service territory that is not served by natural gas.

In general, and under usual circumstances, NW Natural would not extend service to a new community if projected loads and costs result in an expectation of an uneconomic investment.

Respondent: C. Alex C. Miller, General Manager Rates & Regulatory Affairs

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 22 Original Sheet X-1

SCHEDULE X

DISTRIBUTION FACILITIES EXTENSIONS
FOR APPLICANT-REQUESTED SERVICES AND MAINS

AVAILABLE:
In all territory served by the Company under the Tariff of which this schedule is a part.

APPLICABLE:
To the installation of Distribution Facilities to a bona fide Applicant(s), including Service Lines, meters, Main Extensions, and other facilities. For purposes of this schedule, the term Applicant will apply to both new and existing Customers.

APPLICANT QUALIFICATIONS AND RESPONSIBILITIES:
An Applicant may be required to sign a Distribution Facilities Extension Agreement or other Service Agreement, as deemed appropriate by Company, before commencement of construction.

All Applicants must meet the credit criteria set forth in **RULE 2** before construction and activation of any Distribution Facilities, and Applicant must agree to take and pay for service in accordance with all applicable schedules, General Rules and Regulations of this Tariff, and in accordance with the provisions and conditions of the rate schedule under which service will be provided by the Company.

A large Commercial, Industrial, or Institutional Applicant, defined as one whose estimated usage is more than 20,000 Therms per year, will be required to provide at least twelve (12) months written notice prior to the desired service delivery date. Service may be provided before the twelve (12) month period expires, at Company discretion.

Applicant is responsible for the installation and maintenance of appliances and House Line, and is responsible for assuring that all equipment and House Line installations conform with applicable laws, codes, and ordinances of all governmental authorities having jurisdiction. See **RULE 18** for additional information.

Applicant/Customer shall be responsible for notifying the Company of any equipment installations or removals at the Premise during the three-year period following the construction of facilities for the purpose of determining whether or not an adjustment to the original Allowance is appropriate, to determine if a refund situation exists, or to determine if a change in rate schedule is warranted.

If after three (3) months following the date the Company is first ready to serve the site the Applicant fails to take service, or fails to install and connect equipment previously committed, the Company may bill the Applicant for actual construction costs and expenses of the installation, less any Construction Contribution paid. This amount may be subject to refund under this schedule. See **REFUNDS OF CONSTRUCTION CONTRIBUTIONS**.

(continue to Sheet X-2)

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NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 22

First Revision of Sheet X-2
Cancels Original Sheet X-2

SCHEDULE X

DISTRIBUTION FACILITIES EXTENSIONS
FOR APPLICANT-REQUESTED SERVICES AND MAINS
(continued)

LOCATION OF FACILITIES:
The Company reserves the right to designate the location of the Distribution Facilities required to serve an Applicant, including but not limited to, the location of the Service Line, meter(s), and regulators.

Rights-of-way or easements may be required by the Company if any of the Distribution Facilities must cross property owned by Applicant or third parties.

MAIN LINE FACILITIES.
The length and normal route of a Main Extension will be determined by the Company and considered as the distance along the shortest, most practical, available, and acceptable route that is clear of obstructions from the nearest permanent and available Main to the point that the Service Line(s) will be connected.

The Company, in its sole discretion, may select an alternate route, or may extend a Main beyond the point required to serve an Applicant(s) where Company considers it to be in the public or the Company's interest.

SERVICE LINE FACILITIES.
The length of the Service Line will be determined by the Company as the distance along the shortest, most practical, available and acceptable route, that is clear of obstructions from the Main to the meter location. In most instances, the Service Line footage will be measured from the Applicant's property line to the meter location.

The Company shall install excess flow valves on service lines as dictated by the Company's Standard Practices. (N) (N)

METER FACILITIES.
The gas meter installation will be at a location of Company's designation, as dictated by the Company's Standard Practices governing meter location.

Where separate meters are installed to measure gas supplied to multi-family dwellings or to separate tenants in Commercial buildings, the property owner will be responsible for identifying the Premise or address for the House Line to be served by each meter.

(continue to Sheet X-3)

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 22

Substitute Second Revision of Sheet X-3
Cancels First Revision of Sheet X-3

SCHEDULE X

DISTRIBUTION FACILITIES EXTENSIONS
FOR APPLICANT-REQUESTED SERVICES AND MAINS
(continued)

CONSTRUCTION COSTS AND SCHEDULING: (C)(D)
(N)

Construction costs for Main Extension and/or Service Line installations are determined utilizing a best construction practices approach. Construction cost calculations will include all costs associated with the extension of the Company's Distribution Facilities, up to and including the installation of the meter. Site-specific cost estimating will be used by the Company when, in the Company's sole determination, such cost-estimating practices are warranted. Construction and construction-related costs are determined according to the Company's Engineering Procedures Cost Estimating Guide, as updated from time to time.

Scheduling for the construction of main extensions shall be at the dates and times determined by the Company, in its sole discretion. When scheduling the construction of new main extensions, the Company will consider several factors, including but not necessarily limited to, crew availability, type of construction, weather conditions, time of year, and number of bona fide gas service applicants.

Generally, the construction of Residential service line extensions from an existing main will be scheduled within thirteen (13) working days of the date an application for service is approved, but may be subject to change for reasons including, but not necessarily limited to, crew availability, weather conditions, and type of construction. The Company will accommodate an approved Residential Applicant's request for a specific installation date whenever regular-time construction crews are available, at no charge. Applicants whose situation is such that their health or well being would be at risk if the installation is not completed in five days or less will be given first priority in the company's construction schedule and no charge will be assessed. In all other instances, in the event a priority request cannot be accommodated with the use of regular-time construction crews, the company will offer residential applicants a "for fee" priority scheduling option. Applicants who choose to pay the $200 priority fee will receive a firm installation date within five (5) working days of the date the application for service is approved. The priority fee will be used to cover the costs associated with over-time installation, or the hiring of contract construction crews. The company will not accommodate a "for fee" priority request if it would adversely affect the quality, or timing, of installations for other customers or prospective customers. The priority scheduling option is only available between September 1 and January 31. The payment of the priority fee shall be due prior to the construction of the service line extension, unless other payment arrangements acceptable to the Company are made. In the event the company fails to complete installation by the priority date, the priority charge will be waived or refunded. The fee paid for priority installation is not subject to refund under the Refunds of Construction Contributions section of this Schedule X.

Non-Residential service line extensions from an existing main will be scheduled as soon as practicable following the date an application for service is approved, based on the size of the project and type of construction required. The Company will make its best effort to accommodate any special scheduling needs on a project by project basis. (N)

CONSTRUCTION ALLOWANCE:

Except as specifically noted otherwise in this section, an Applicant will receive a Construction Allowance equal to 5.0 times the Base Distribution Rate stated in the applicable rate schedule, times the standard

(continue to Sheet X-4)

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SCHEDULE X

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DISTRIBUTION FACILITIES EXTENSIONS
FOR APPLICANT-REQUESTED SERVICES AND MAINS
(continued)

CONSTRUCTION ALLOWANCE (continued):
consumption factor(s) associated with the specific equipment committed to be installed. The standard consumption factor(s) assume usage in a permanent structure occupied twelve (12) months per Year, and may be adjusted where service is requested to vacation homes, rental homes, or any seasonally operated establishment where occupancy is known or expected to be less than twelve (12) months per Year. The consumption factors shall be set forth in the Guide Book.

For Non-Residential equipment and uses not specifically identified in the Guide Book, the Construction Allowance calculation will use a consumption factor based on the nameplate rating of the equipment, or the Construction Allowance may be based on equipment consumption comparisons of like Customers, whichever is determined by the Company to most accurately reflect the revenue expected to be derived from the Applicant(s).

Applicants requesting service for new residential housing tracts, Commercial shopping, or similar new developments, will receive a Construction Allowance based on the margin revenue estimated to be derived from the development by the end of the third Year following installation.

A large Non-Residential Applicant will receive a Construction Allowance based upon a Customer-specific financial analysis that will incorporate the Customer's Contract terms and conditions.

Applicants requesting service for equipment served under **SCHEDULE 1**, for equipment to be used for Standby or emergency purposes, or for temporary service installations, will not receive a Construction Allowance.

CONSTRUCTION CONTRIBUTION:
The estimated cost to construct the Distribution Facilities required to serve an Applicant(s) will be offset by the Applicant's Construction Allowance. If the Allowance is greater than the cost of construction, the installation will be performed at no charge. If the cost of construction is greater than the Construction Allowance, the Applicant must pay a Construction Contribution equal to the difference between the cost of construction and the Construction Allowance, plus the tax effects on the Construction Contribution amount at 33.75%, calculated by multiplying the Construction Contribution by 1.3375. (C) (C)

Applicants requesting service for equipment served under **SCHEDULE 1**, for equipment to be used only for Standby or emergency purposes, or for temporary service installations under **RULE 22**, will be required to pay the entire cost of constructing Distribution Facilities to serve the location.

Where service is requested for manufactured housing developments, mobile home developments or house boat moorage developments, the Applicant shall be required to pay the entire cost of constructing Distribution Facilities to serve the location before commencement of construction, subject to refund as specified in this Schedule. The Company may make exceptions to the advance payment requirement where, in the Company's sole judgment, good cause exists. The conditions for such exceptions will be specified in the service installation agreement.

Construction Contributions must be received prior to commencement of construction, and may be refundable. See **REFUNDS OF CONSTRUCTION CONTRIBUTIONS**.

(continue to Sheet X-5)

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 22

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SCHEDULE X

DISTRIBUTION FACILITIES EXTENSIONS
FOR APPLICANT-REQUESTED SERVICES AND MAINS
(continued)

INFILL/EXFILL POTENTIAL ANALYSIS: (M)
At Company's sole discretion, an Infill/Exfill-Potential Analysis may be performed in conjunction with an Applicant's request for service when a Main Extension is required. If an Infill/Exfill-Potential Analysis is performed, and it results in a reduction in the required Construction Contribution, the Applicant(s) will choose to either pay the reduced Construction Contribution and waive the right to any refunds, or pay the larger Construction Contribution, subject to possible future refund. (M)

REFUNDS OF CONSTRUCTION CONTRIBUTIONS:
Construction Contributions may be subject to refund for a period of three years following the date the Distribution Facilities are first ready to serve the Applicant. The Company will automatically review those accounts involving a Main Extension on the anniversary date of the third Year to determine if a refund situation exists. Upon request, or upon notification by Customer of a change of service address, the Company will review the Customer account for possible refunds prior to the end of the third year. Any amounts not refunded within the three (3) year period will be retained by the Company.

All refunds will be calculated using construction costs, consumption factors, and Base Distribution Rates in effect at the time the initial application was accepted by the Company. In no event will the refund exceed the amount of the original contribution. All refunds are payable to the original contributor or their designee.

Customer may be eligible for a full or partial refund at any time during the three (3) year refund period where one or more of the following conditions applies:

1. A CHANGE IN RATE SCHEDULE QUALIFICATIONS
   A refund may be available if the initial application was for service to equipment served under **SCHEDULE 1**, or for service to equipment for Standby or emergency purposes served under **SCHEDULE 3** or **SCHEDULE 4**, and equipment is subsequently installed that eliminates the Standby-only status, or that qualifies Customer for service under a different schedule.
2. APPLIANCE ADDITIONS.
   A refund may be available if additional equipment is subsequently installed by Customer and Company determines that the associated increase in estimated revenue from the service site is sufficient to cause a refund. This does not apply to the addition of equipment of the type stated under **SCHEDULE 1**.
3. TEMPORARY INSTALLATIONS.
   A refund may be available where the initial application was classified as a temporary service installation and the Company changed the status to permanent on or before the end of the thirty-sixth (36) month following the date the service was activated.

(continue to Sheet X-6)

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Effective with service on
and after October 25, 2000

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 22 Original Sheet X-6

SCHEDULE X

DISTRIBUTION FACILITIES EXTENSIONS
FOR APPLICANT-REQUESTED SERVICES AND MAINS
(continued)

REFUNDS OF CONSTRUCTION CONTRIBUTIONS (continued):

4. **SERVICE LINE CONNECTIONS FROM A MAIN EXTENSION.**
A refund may be available if subsequent Service Line connections are constructed from a Main Extension for which a Construction Contribution was paid, and for which an outstanding amount is subject to refund. The refund will be dependent on the amount of additional Allowance the subsequent service connection(s) provide to offset the Construction Contribution of the original contributor(s).

5. **MAIN EXTENSION.**
A refund may be available if the actual cost of constructing a Main Extension is less than the site-specific cost estimate. In such case, the refund will be the difference between the actual and the estimated cost.

6. **SERIES OF MAIN EXTENSIONS.**
A refund may be available where there are a series of Main Extensions, commencing with a Main Extension having a Construction Contribution subject to refund, and each additional Main Extension is dependent upon the previous Main Extension as a direct source of supply and is installed at no charge to Applicant(s), a series refund will be made as follows:

a) Additional connections supplied from a Main Extension on which there is a refundable amount will provide refunds first to the extension to which they are connected; and
b) When the amount subject to refund on an extension in a series is fully refunded, the excess refundable amount will provide refunds to the extension having the oldest outstanding amount subject to refund in the series.

GENERAL RULES AND REGULATIONS:
Service under this schedule is subject to the General Rules and Regulations contained in this Tariff and to those prescribed by regulatory authorities, as amended from time to time.

Issued September 14, 1998
NWN Advice No. OPUC 98-17

Effective with service on
and after ~~November 1, 1998~~
DEC 02 1998 KW

Issued by: NORTHWEST NATURAL GAS COMPANY
d.b.a. NW Natural
220 N.W. Second Avenue
Portland, Oregon 97209-3991

NW Natural

Rates & Regulatory Affairs

Company Response to UG 152 Staff Requests

January 28, 2003

289. Are there communities in your service territory that NW Natural, despite interest from potential customers, has elected not to extend service? Please discuss each community in detail, e.g., why has NW Natural not extended distribution service to Estacada?

Response:

Yes. There are communities where NW Natural has not extended service based on the company's analysis of the investment. One such decision known to have occurred was in 1997, where the company conducted an analysis regarding the extension of service to Gates, Oregon and that extension did not take place. A copy of that analysis is attached.

There are a number of potential extensions currently under review, but no final decision regarding the investment has been made. These include, but are not necessarily limited to the extension of distribution service to Estacada, Dayton, Dallesport, Veneta and Damascus. Other extensions under consideration include expansions of the company's distribution system within currently served communities to accommodate recent or future expected growth in those areas. Often these expansion areas adopt unique names, but are part of a larger city or town. For example, Youngs River, which is a small community located in Astoria, Oregon.

The company does not extend service when the investment cannot be supported by the amount of prospective load available under reasonable conversion and economic growth criteria. The conversion criteria we use includes the following: the ages and fuel type of existing equipment, the types of equipment to be installed in the target facilities, the size and age of the target facilities, discretionary income levels, and costs of competing fuels. Economic growth criteria include the plans of residential, commercial and industrial property developers. The company's analysis determines how much, if any contribution-in-aid-of construction must be collected from customers to support the investment. Often, it is the community that makes the election not to extend service based on the company's required contribution-in-aid-of construction.

Although the extension is still under review, NW Natural has not extended service to Estacada as our analysis indicates it is not economic for us to do so at this time given the current cost and load estimates. Residents of Estacada with whom NWN has met with regarding extending service to Estacada have indicated that they would not be

Respondent: Dennis L. Henderson, General Manager ICOM

willing to make a contribution in aid of construction payment that would help make it cost effective. Future expansion to Estacada has not been ruled out given the expected expansion of the urban growth boundary over the next few years that will require expansion of the distribution system toward Estacada. As the distribution system is expanded to meet Portland's growth plans, the economics of serving Estacada may improve.

NW Natural regularly studies system expansion opportunities and looks for the most opportune time to reach new areas in the most cost effective manner. For example, the south coast region (Coos County) represents a unique opportunity to extend our distribution system, chiefly because the County and the State of Oregon have funded the cost of a transmission line that will bring gas to gate stations located at each of the County's major municipalities.

Staff/102
Tatom/10

NORTHWEST NATURAL GAS COMPANY

220 N.W. SECOND AVENUE PORTLAND, OREGON 97209 - 3991

Rates & Regulatory Affairs
Integrated Resource Planning
(503) 226-4211

May 19, 1997

Mr. and Mrs. Stevens
137 Santiam St.
Gates, Oregon 97436

Re: ***Cost to Serve Analysis - City of Gates, Oregon***

Dear Mr. and Mrs. Stevens:

The analysis of the cost to bring natural gas service into the City of Gates, Oregon has been completed. A detailed cost breakdown is enclosed for your information.

The total cost to bring service into the area is estimated at $342,639. The analysis of the estimated revenue that could be expected from future potential residential and commercial customer additions was factored into the cost to serve equation to derive the construction contribution required to bring natural gas service into the city. This revenue analysis is based on the best information available at this time, which includes 106 houses of about 800 square feet in size, one high school, two churches, one motel, ten small businesses and three small restaurants in the Gates area. The analysis indicates that a construction contribution in the amount of $156,960 would be required before construction could begin.

The construction contribution was determined in accordance with the Company's Infill Potential Analysis, which allows the company to take into consideration the potential for all customer additions at the time of the original request. This means several things. First, the information provided includes all potential customer hook-ups available in the area at this time. Second, by considering all potential customers in the initial cost to serve calculation, there are no possibilities for a refund of any construction contribution paid for the main extension into the city. The Infill Potential Analysis process is explained on Sheet RR-13 of Rule 12, enclosed for your information.

There are a number of factors that impact the revenue side of the calculation. The most significant are the size of the potential homes and the current home heating source. Our canvass of the area indicates that most of the homes are 800 square feet in size and are heated with electric baseboard, propane or wood. This means that the probability of these customers converting to natural gas at some point in the future is very small, primarily because the cost of doing so far exceeds the benefits that would be derived from the conversion. Other factors include the number of individuals who are ready to commit to converting at this time, and the future growth of the community.

Although our canvass of the area revealed interest in natural gas coming to the community, in nearly every instance, budget constraints prevented anyone from committing to converting to natural gas at this time. And, because there is no evidence of future growth in the area, the analysis must be limited to existing residential homes and commercial establishments.

Please call me at (503) 226-4211, extension 3582, or Dave Williams, District Manager of our Salem office at (503) 585-6611 should you have any questions about this information.

Very truly yours,

Richard J. DeFerrari,
Assistant to Vice President's of
Marketing and Regulatory Affairs

Enclosures

cc: Al Jasso, OPUC
Dave Williams, Salem Office
Onita King, Regulatory Affairs

Staff/102
Tatom/12

Avista Corp.
1411 East Mission PO Box 3727
Spokane, Washington 99220-3727
Telephone 509-489-0500
Toll Free 800-727-9170

AVISTA Corp.

RECEIVED
JAN 30 2003
P.U.C.

January 29, 2003

Bonnie B. Tatom
Program Manager, Natural Gas Rates and Planning
Oregon Public Utilities Commission
P.O. Box 2148
Salem, OR 97308-2148

RE: Extension of Utility Distribution System Information Request

In regards to your recent information request on company policies and procedures associated with extension of our utility distribution system into new communities, we provide the following responses:

1. Please discuss how the company has supported and justified extending its distribution system to new communities over the last 20 years.

   Response: The policies and procedures that Avista follows for its main extensions in Oregon are outlined in Rule No. 15-Gas Main Extensions, contained in its approved tariffs. In summary extensions are calculated using our line extension tariff of three (3) times estimated annual gross revenues as determined by the Company. From time to time, extensions have become cost effective due to changing circumstances, such as PGT going through Keno in Klamath County, or mint processing plant conversions bringing our system closer to Cove and Summerville in Union County.

2. Please name the incorporated communities in your service territory that are currently not served by natural gas.

   Response: In Jackson County: Shady Cove, Ruch, Prospect, and Butte Falls; in Douglas County: Glide; in Klamath County: Chiloquin, and Bonanza; and in Union County: Enterprise/Joseph.

3. In general, why would your company not extend service to a new community?

   Response: Any communities not served are due to financial limitations on capital investment relative to the revenue forecast for that community. It has not been our practice to attempt to expand to new towns that will put rate pressure on existing customers. Communities have the option of contributing capital dollars to proposed projects to make them more cost effective.

4. Are there communities in your service territory that you, despite interest from potential customers, have elected not to extend service? Please discuss each community in detail.

   Response: Two examples are Shady Cove in Jackson County and Chiloquin in Klamath County.

In the case of both, the dwellings are spread out so that our revenue allowance would cover connections within the towns, but would be insufficient to provide for the lateral line to the towns. In Chiloquin, the PGT mainline is 14 miles east of town. There is not sufficient revenue within the town to justify a lateral of that length. In Shady Cove, our nearest facilities are about 9 miles distant, and are insufficient at that point to serve the town without backtracking another 3 miles to obtain high-pressure gas.

5. Over what time period is the investment by the company expected to be cost effective?

   Response: Our revenue requirements model considers the entire depreciable life cycle of the plant installed, usually 40 years on a levelized basis.

6. Does the company complete extensive marketing studies when making a decision to extend service into a new community?

   Response: When considering a new town, a team of construction and financial people are sent to the town to complete an infrastructure model of the town to ascertain construction costs. Customer connects are estimated based on the proportion of competing fuel users expected to convert. Much of this analysis is based on price differential, with the balance based on estimates of disposable income.

7. How does the company determine that extending its distribution system to a new community is a prudent decision?

   Response: We will typically run our estimated construction costs, as well as revenue data through a revenue requirements model, estimating the revenue requirement based on our authorized rate of return and capital structure. For an extension to be determined prudent, the resulting present value cash flow analysis must generate a return equal to or in excess of our weighted average cost of capital.

These responses are being supplied for informational purposes as to how Avista has operated historically for our Oregon natural gas properties.

Sincerely,

Don Falkner

Don Falkner
Manager, Revenue Requirements

P.U.C.

CASCADE NATURAL GAS CORPORATION

222 FAIRVIEW AVENUE NORTH SEATTLE, WASHINGTON 98109-5312 206-624-3900
FACSIMILE 206-624-7215

January 23, 2003

Bonnie B. Tatom
Program Manager, Natural Gas Rates & Planning
OPUC
550 Capitol Street NE, Suite 215
Salem, OR 97301-2557
(503) 378-8225
Fax: (503) 373-7752

Below is Cascade's response to your request for information regarding Cascade's extension of its distribution system over the past 20 years.

1. Please discuss how the company has supported and justified extending its distribution system to new communities over the last 20 years.

   Cascade has justified extending its distribution system to new communities over the last 20 years by adhering to its Rule 8 tariff - Main Extensions. The communities Cascade has extended service to over the past 20 years typically have one or more major industrial customers that have provided a large portion of the margin required to justify the extension investment. These communities include Irrigon, Boardman, Vale and LaPine.

2. Please name the incorporated communities in your service territory that are currently not served by natural gas.

   The Oregon communities not currently served by Cascade include Ione, Haines, Helix, Adams, Echo, Tumalo, Sisters and Culver.

3. In general, why would your company not extend service to a new community?

   Cascade would not extend service to a new community if the community is not willing to pay the incremental costs required to provide natural gas distribution facilities and services.

4. Are there communities in your service territory that you, despite interest from potential customers, have elected not to extend service? Please discuss each community in detail.

   No.

5. Over what time period is the investment by the company expected to be cost-effective?

   Cascade expects an investment to be cost effective (meet minimum return on investment) within 38 years.

6. Does the company complete extensive marketing studies when making a decision to extend service into a new community?

   Cascade completes a market study by surveying a new community to determine how many new customers can be expected within the first ten years.

7. How does the company determine that extending its distribution system to a new community is a prudent decision?

   Cascade would consider an extension of its distribution system a prudent decision if the anticipated margins from committed and projected customers, along with applicable customer contributions provides an IRR in a discounted cash flow analysis at or above our last allowed rate of return.

Sincerely,

CASCADE NATURAL GAS CORPORATION

Will Odell
VP, District Operations

NW Natural

Rates & Regulatory Affairs

Company Response to UG 152 Staff Requests

January 21, 2003

287. Please name the incorporated communities in your service territory that are currently not served by natural gas.

Response:

The following is a list of incorporated cities within NWN's service area not presently being served with gas:

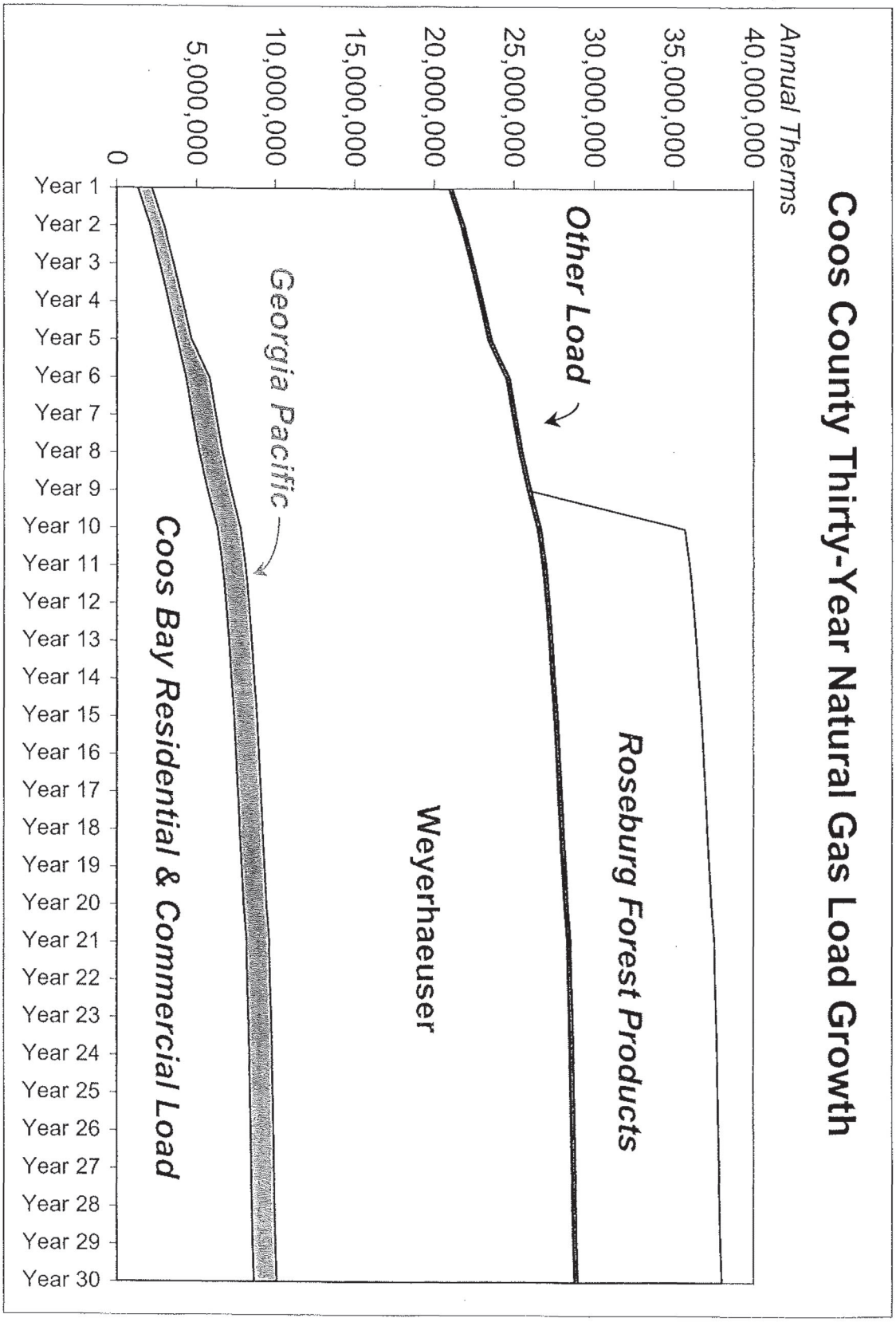
Bay City
Cascade Locks
Dayton
Estacada
Falls City
Florence
Garibaldi
Gaston
Gates
Lowell
Manzanita
Monroe
Mosier
Nehalem
Prescott
Rockaway Beach
Scotts Mills
St. Paul
Tillamook
Veneta
Waldport
Wheeler
Yachats
Yamhill

Respondent: Dennis L. Henderson, General Manager ICOM

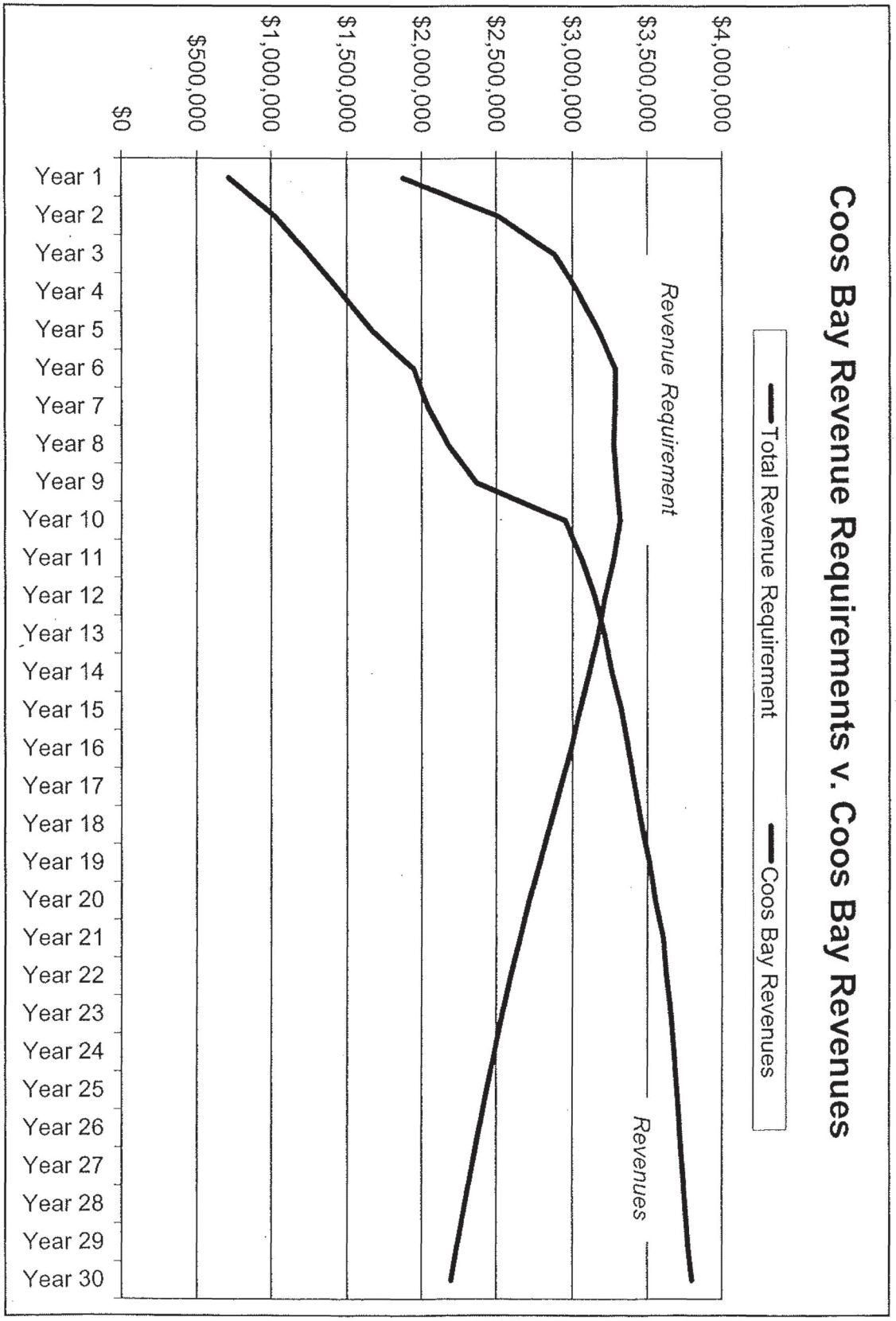
The following is a list of cities within NWN's service area not presently being served with gas located in Coos, Lane or Douglas Counties.

Coquille
Coos Bay
Drain
Dune City
Elkton
Lakeside
Myrtle Point
North Bend
Powers
Reedsport

Staff/102
Tatom/18



Staff/102
Tatom/19



NW Natural

Rates & Regulatory Affairs

Company Response to UG 152 Staff Requests

January 27, 2003

290. How severe is the threat of industrial bypass in the Coos County service territory?

Response:

In Coos County, NW Natural's distribution system would be bypassed by a connection to the County pipeline as opposed to the Williams-West system. The threat of industrial bypass in the Coos County service territory for any given customer is different from the risk faced by NW Natural elsewhere in its service territory, for two reasons. .

First, although the County pipeline is not state or federally regulated, it terminates within territory exclusively allocated to NW Natural, and it thus falls within the Commission's authority to regulate under Oregon's Territory Allocation Law. That law would prohibit the County from serving customers through direct bypass.

Second, the partnership between Coos County and NW Natural to bring natural gas to the region allowed the Company to negotiate exceptions to the bypass prohibition described above. Specifically, the bypass provisions contained in Article 8 of the Transportation Service Agreement represent the parties' attempt to strike a balance between protecting NW Natural's Coos County investment from bypass risk while still allowing the County to provide a direct connect to capture economic development opportunities, but only under very limited market circumstances.

If the Commission approves the Transportation Service Agreement as a contract to allocate service territory, then that agreement will be enforceable and Article 8 will contractually control the risk of bypass. A copy of the Transportation Service Agreement is attached to the Company's filed testimony as Exhibit NWN/1501. The severity of the risk, therefore, depends on (1) the language of Article 8 and (2) the extent to which high-volume commercial and industrial gas users (designated as "Eligible Customers" under the Agreement) locate in Coos County.

Respondent: Dennis L. Henderson, General Manager ICOM

Coquille, OR
(Coos Co.)
Valley Sentinel
(Cir. W. 4,695)

JAN 2 9 2003

Allen's P. C. B. Est. 1888

Gas pipeline construction to begin April 15

By Robert Jump 5019

Construction of a natural gas pipeline to be built from Roseburg to Coos Bay is scheduled to begin in Douglas County on April 15.

According to Steve Shute, Pipeline Solutions project coordinator, the pipeline will most likely be started in Douglas County due to climactic conditions. Bidding documents were posted on Coos County's Internet web site on Jan. 22 and have been mailed to contractors who participated in a walking inspection of the pipeline's route.

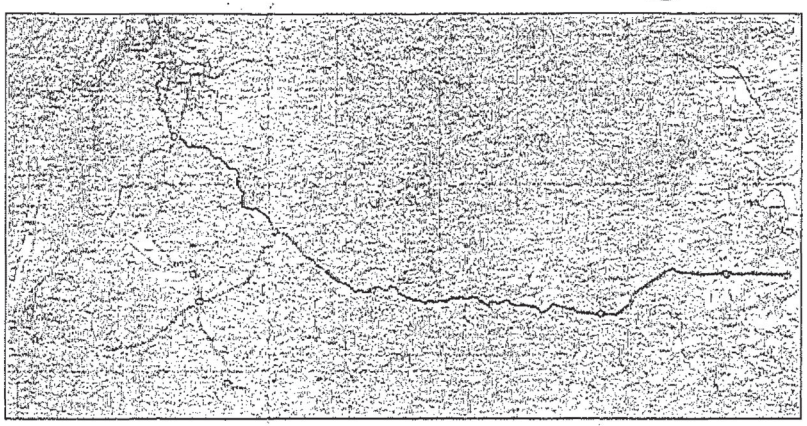
"Northwest Natural has a couple of items to clear up with the PUC (Public Utilities Commission)," Shute told *The Sentinel* Monday. "The construction date coincides with that."

According to the bidding documents, the 12 inch pipeline will be buried a minimum of 36 inches and where it will cross railroad right of ways or streams, will be a minimum of 72 inches from the surface. All welds are to be examined using x-ray technology. In addition, the pipeline will be pressure tested for leaks before gas is transported through the line.

The approximately 55 miles of pipeline will connect to Williams Gas Pipeline at a meter facility southwest of Roseburg. From there, the pipeline route follows about 12 miles of existing rights-of-way for public roads or for Pacific Power & Light and Bonneville Power Administration transmission powerlines. The route traverses the settlements of Lookingglass and Flournoy Valley to a crossroad called Reston to the Coos/Douglas County line. The pipeline will cross Brewster Canyon and go through Dora, Sitkum, McKinley and Fairview. The pipeline will then travel through the Blue Ridge area to Isthmus Slough on to Englewood and Coos Bay. About 4.5 miles of the pipeline will cross Bureau of Land Management land.

In 1999, a study leading up to the County referendum election proposed the route follow Highway 42. The pipeline would have connected to Williams at Winston, then run through Myrtle Point and Coquille to Coos Bay. However, the proposed route was 25 miles longer than the Coos Bay Wagon Road route.

The Highway 42 route would have placed the pipeline entirely within the highway right-of-way following Shields Creek and the Middle Fork of the Coquille River. The route would also have to cross along more flowing streams and was much longer. The pipeline along the Highway 42 route would have been about 70 miles along streams versus about 14 miles for the current route.



Map shows the route of the gas pipeline. Main pipeline route is in blue and yellow with laterals in red.
(Map taken from Environmental Impact Statement.)

County officials decided that the Highway 42 route was infeasible because of difficult construction. Numerous settlements and towns along the route where it would run would be difficult to traverse within the highway right-of-way, according to Coos County documents. In addition, there are about 38 miles of canyon, where crews would have a difficult time building the pipeline.

According to county documents, a 12-inch pipeline is the break between large diameter and small diameter projects and contractors usually ask for at least 50 to 75 feet in working space. The pipeline would have to be placed in a slot between pavement and highway guardrails or rock faces that narrow to two-three feet wide. An active fiber optic cable is already buried on each side of the highway. In addition, there would have been about seven miles of rock that would have needed to be excavated. The Oregon Department of Transportation expected to maintain normal traffic access for more than 20,000 cars per day during the pipeline's construction.

Pipeline laterals will be constructed of either four or six inch pipe for gas service to Coquille and Myrtle Point. A lateral could also be built to Bandon. The lateral routes are expected to follow powerline, state highway, Railroad and county road right-of-ways.

According to Shute, pipeline officials are now discussing easements with private landowners along the lateral routes. However, the final lateral route has not been established.

"We're trying to get a feel for landowner sentiments for the project," Shute said. "It seems to be going pretty well."

According to Shute, Pipeline Solutions has contacted "quite a few landowners."

Blasting and construction seasonal restrictions are in place to protect spotted owls and marbled murrelets. In addition, monitoring for archeological and tribal artifacts will be instituted.

The cost of the project is estimated at $51 million instate and local funding.

Shute estimates the pipeline system will cost about $200,000 per year to operate. The figure includes the full cost of labor, liability insurance, communications and other costs. The County plans to recover the full cost of operation with transportation fees charged to gas shippers. During the beginning of operation, the transport fees will be set at the estimated annual cost of operations. As the amount of gas transported grows, the transport fee will be charged on gas volumes actually transported. Excess fees received can be used to pay interest and debt, within the limits of tax exempt financing.

According to Shute, Coos County has the largest population of any county in the U.S. without natural gas service.

List: **UG 152** OFFICIAL SERVICE LIST Printed: 3/3/2003

Interest Type(s): **Parties**

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List: **UG 152** OFFICIAL SERVICE LIST Printed: 3/3/2003

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PAULA E PYRON
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DONALD W SCHOENBECK
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VANCOUVER WA 98660-3455

List: **UG 152** OFFICIAL SERVICE LIST Printed: 3/3/2003

Interest Type(s): **Parties**

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JAY T WALDRON
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4422 OREGON TRAIL CT NE
SALEM OR 97305

Labels: 19

CERTIFICATE OF SERVICE

UG 152

I certify that I have, this day, served the foregoing document upon all parties of record in this proceeding by mailing a copy properly addressed with first class postage or first class equivalent prepaid to all parties or attorneys of parties.

Dated at Salem, Oregon, this 7th day of March, 2003.

Stephanie S. Andrus
Assistant Attorney General of Attorneys for
Public Utility Commission's Staff
100 Justice Building
Salem, Oregon 97310
Telephone: (503) 378-4620

AAG/SA

UG 152

RECEIVED

APR 0 9 2003

Public Utility Commission of Oregon
Administrative Hearings Division

UG 152/NWN/1515
Bonnie Tatom,
Dennis L. Henderson,
Bob Jenks,
Donald W. Schoenbeck,
and Nikki Whitty

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

SECOND STIPULATION CONCERNING THE COOS COUNTY DISTRIBUTION SYSTEM

Staff, NW Natural, CUB, NWIGU, Coos County

Joint Direct Testimony of
Bonnie Tatom, Dennis L. Henderson, Bob Jenks,
Donald W. Schoenbeck, and Nikki Whitty

DOCKETED

April 2003

Staff-NWN-CUB-NWIGU-Coos County/1515
Tatom-Henderson-Jenks-Schoenbeck-Whitty/1

Q. Please state your names and positions.

A. My name is Bonnie Tatom. I am a member of Staff of the Oregon Public Utility Commission. I have previously filed testimony in this docket.

My name is Nikki Whitty. I am one of three elected County Commissioners for Coos County, Oregon. I have previously filed testimony in this docket in support of the Stipulation Relating to the Coos County Distribution System (the "First Stipulation").

My name is Bob Jenks. I am executive director of the Citizens' Utility Board ("CUB"). I have previously filed testimony in this docket.

My name is Dennis L. Henderson. I am employed by Northwest Natural Gas Company ("NW Natural") as the General Manager of the company's Industrial-Commercial Business Solutions Department. I have previously filed testimony in this docket.

My name is Donald W. Schoenbeck. I am a principal of Regulatory & Cogeneration Services, Inc., which is employed as a consultant in this docket by the Northwest Industrial Gas Users ("NWIGU"). I have previously filed testimony in this docket in support of the First Stipulation.

PURPOSE AND BACKGROUND

Q. What is the purpose of your testimony?

A. The purpose of our joint testimony is, first, to describe and support the Second Stipulation Relating to the Coos County Distribution System (the "Second Stipulation") between Commission Staff, NW Natural, CUB, NWIGU, and Coos County (together, the "Parties"). Second, our testimony will address the nine questions posed by the Commission following the oral argument on March 20, 2003.

Q. Please describe the background for this Second Stipulation.

Staff-NWN-CUB-NWIGU-Coos County/1515
Tatom-Henderson-Jenks-Schoenbeck-Whitty/2

A. With the exception of the City of Bandon, Coos County is within NW Natural's exclusive service territory. The company presently provides propane service in Coos County. In 1999, the state approved lottery bonds and Coos County voters authorized general obligation bonds to cover the cost of a sixty-mile gas transmission pipeline that would route natural gas from the Williams pipeline, at a point near Roseburg, to the south coast (the "County pipeline").

In July 2001, NW Natural and Coos County entered into a Transportation Service Agreement (the "Transportation Agreement") under which NW Natural agreed to construct certain minimum distribution facilities, through which the company will serve distribution customers by transporting its own gas through the interstate pipeline, purchasing gas transportation services on the County pipeline, and then delivering gas on its local distribution system to customers under appropriate tariffs. NW Natural may also provide local gas transportation services to industrial customers, from the County pipeline to the customers' facilities. The Transportation Agreement contains several conditions precedent to NW Natural's obligation to construct a distribution system, including Commission approval of the company's proposal concerning statewide rate treatment of the initial investment in Coos County distribution. NW Natural requested such approval from the Commission in a declaratory ruling docket, DR 30. While that decision was pending, however, NW Natural filed an application for a general rate revision, including its Coos County rate proposal. The DR 30 docket was closed and an expedited schedule for the Coos County issue was established in this rate case on January 10, 2003.

At the end of February 2003, NW Natural, NWIGU, and Coos County entered into the First Stipulation resolving, between those parties, issues relating to the rate

treatment of NW Natural's investment in the Coos County Distribution System (the "CCDS"). In settlement conferences in March and April 2003, the Parties to this Second Stipulation reached agreement concerning rate treatment of NW Natural's investment in the CCDS. This Second Stipulation supersedes the First Stipulation.

THE SECOND STIPULATION

Q. Please summarize the proposal for cost-sharing set forth in the Second Stipulation.

A. The Second Stipulation defines the scope of NW Natural's proposed initial investment in the CCDS, which totals an estimated $12 million and which, for purposes of the rate proposal set forth in the Second Stipulation, is capped at that amount. The Second Stipulation describes a cost-sharing mechanism for the initial investment that is based on NW Natural's main extension policy in Tariff P.U.C. Or. 22, Schedule X. Specifically, the main extension allowance is five times projected annual margin revenue. In the case of the CCDS, the Parties now agree that the projected annual margin revenue is $2 million and the main extension allowance is $10 million.

Normally, Schedule X would require Coos County to pay amounts in excess of the main extension allowance — that is, $2 million — in advance of construction. However, because of the contributions both the County and the State have already made to finance the sixty-mile County pipeline, the Parties believe it is reasonable in this case to include the entire $12 million in statewide rates and allow the County to repay its $2 million share through the mechanisms specified in the Second Stipulation.

Q. Are the cost-sharing ratios specified in the Second Stipulation the same as Staff's original proposal based on application of Schedule X?

A. No. The original calculation of the main extension allowance under Schedule X resulted in a cost-sharing ratio of approximately 50/50. However, that calculation did not include

demand charges in projected revenues, and the Parties agree those charges should be included under the terms of Schedule X. When NW Natural recalculated projected margin revenues to include demand charge revenues, the resulting cost-sharing was $10 million/$2 million as described above, or approximately an 83/17 percent split.

Q. Please describe the repayment mechanism proposed in the Second Stipulation.

A. The initial investment in the CCDS, not to exceed $12 million, will be placed into rate base and the revenue requirement will be included in rates effective with the distribution system's in-service date, subject to audit and review procedures. However, the amount of the CCDS investment in excess of the main extension allowance of $10 million will be repaid to statewide customers over time, through (1) collection of a separate charge from Coos County customers, (2) a $400,000 credit adjustment by NW Natural, and (3) revisions to the Transportation Agreement reducing NW Natural's charges for transportation on the County pipeline.

First, NW Natural will impose a charge on Coos County natural gas sales service customers (the "Coos County Charge") of $0.02 per therm during the first twenty years of service. The Coos County Charge will be applied first to pay NW Natural's costs of transportation services on the County pipeline (as described below), and second to repay to statewide customers the Coos County Share. The "Coos County Share" means the amount of NW Natural's initial investment (capped at $12 million), minus the $10 million main extension allowance, minus NW Natural's $400,000 credit adjustment.

Second, NW Natural will record a credit adjustment to its Oregon customers of $100,000 per year for four years, plus carrying charges, for a net present value of $400,000. This amount will be refunded to statewide customers through NW Natural's

purchased gas adjustment. The credit will be allocated generally to the customer classes expected to contribute toward repayment of the Coos County Share.

Third, Coos County has offered to amend the Transportation Agreement to effectively reduce NW Natural's transportation rate. The Transportation Agreement now specifies a cents/MMBtu rate for transportation on the County pipeline, but the County will change those provisions to cap its transportation charges at an amount equal to NW Natural's volumetric share of operational and maintenance expenses for each year of the first twenty years of the agreement. Those expenses are estimated at approximately $200,000 annually. Once proceeds from the $0.02/therm Coos County Charge exceed the annual O&M amount, the excess will go toward repayment of the Coos County Share. After twenty years, if the Coos County Charge proceeds, combined with contributions of transportation customers, as described below, have not repaid the Coos County Share, then NW Natural will calculate the balance remaining and establish, with the Commission's approval, an appropriate surcharge for Coos County customers until the entire balance has been paid. The Commission will determine at that time the period necessary for recovery of the remainder of the Coos County Share and the allocation of the charge to customer classes.

During the initial years when the Coos County Charge may not be adequate to meet O&M expenses on the County pipeline, the Second Stipulation provides that the balance will be recovered statewide in NW Natural's annual purchased gas adjustment until the Coos County Charge is adequate.

Q. Does the Second Stipulation include contributions by industrial transportation customers?

Staff-NWN-CUB-NWIGU-Coos County/1515
Tatom-Henderson-Jenks-Schoenbeck-Whitty/6

A. Yes, transportation customers will make both a direct and an indirect contribution. First, each transporter on the County pipeline pays its volumetric share of pipeline O&M expenses. For transporters other than NW Natural, transportation charges in excess of this O&M amount will be applied toward repayment of the Coos County Share. Second, industrial customers will have an indirect, positive effect on repayment of the Coos County Share because each additional transporter will proportionately reduce NW Natural's volumetric share of O&M on the County pipeline. This increases the amount of the Coos County Charge that becomes available for repayment.

In addition, for any transportation customer eligible to bypass the CCDS, NW Natural can negotiate a special anti-bypass rate which must be approved by the Commission. At that time, the Commission will consider whether the customer is contributing sufficient amounts to fixed costs, including repayment of the Coos County Share.

Q. Do the Parties predict that the Coos County Share will be entirely repaid within twenty years?

A. Given the degree of uncertainty — of factors such as industrial load growth, for example — it is difficult to predict when repayment will occur. However, given NW Natural's load projections and assuming (1) a $0.02/therm charge on sales service customers and (2) a $0.01/therm transportation charge on the County pipeline for transportation customers, the Parties calculate that the unpaid balance of the Coos County Share would be $73,669 in year twenty.

Q. What assurance do ratepayers have that the roll-in of CCDS costs will be confined to the initial $12 million investment?

A. NW Natural has agreed that, for rate purposes, it will cap its initial CCDS investment at $12 million. The Company has also agreed that, following the initial investment, further extensions of service will be governed by Schedule X.

Q. What other terms does the Second Stipulation include?

A. The Second Stipulation represents a negotiated compromise among the Parties. Thus, the Parties have agreed that no Party shall be deemed to have approved the facts, principles, methods, or theories employed by any other in arriving at the Second Stipulation, and that the terms incorporated in the Second Stipulation should not be viewed as precedent in subsequent proceedings. In addition, the Parties have the right to withdraw from the Second Stipulation if any material part is rejected by the Commission, and the Parties remain free to pursue any appropriate course of action with respect to any issue or matter in this proceeding that is not covered by the Second Stipulation.

Q. Does the Second Stipulation resolve the issue of how rates will be spread among customer classes?

A. No. Each Party retains its original position with regard to rate spread, and the Second Stipulation does not address the issue at all. The exact statewide rate effect of the proposal in the Second Stipulation will depend upon the determination of rate spread in this docket.

Q. What do the Parties recommend regarding the Second Stipulation?

A. We recommend that the Commission admit the Second Stipulation into the UG 152 record and adopt the Second Stipulation in its entirety in determining the rate treatment of NW Natural's initial investment in a Coos County distribution system.

Staff-NWN-CUB-NWIGU-Coos County/1515
Tatom-Henderson-Jenks-Schoenbeck-Whitty/8

ANSWERS TO QUESTIONS POSED BY THE COMMISSION

Q. Please explain how the Parties are responding to the Commissioners' interrogatories.

A. Following the oral argument held on March 20, 2003, the Commissioners forwarded nine interrogatories to all parties in UG 152. The deadline for responses to these interrogatories has been extended to April 9, 2003 in order to allow the Parties to the Second Stipulation to provide answers in this supporting joint testimony. Not all Parties will respond to all nine interrogatories; therefore, the name of the responding witness is provided where only one Party offers a response. In such cases, the Commission should not consider the response indicative of the position of any other Party.

Q. Will the Coos County pipeline be built if no industrial customer chooses to take transportation services from Coos County?

A. *Whitty*: Coos County will build its gas transmission pipeline whether or not any industrial customer arranges for gas transportation services beforehand. The County anticipates that most industrial customers will begin transportation and use of natural gas following construction of the pipeline and the CCDS.

Q. Under what conditions, if any, will Northwest Natural Gas (NNG) build the distribution system in Coos County if no industrial customer chooses to take transportation service from NNG?

A. *Henderson*: NW Natural is obligated, under its Transportation Service Agreement with Coos County, to construct the distribution system, assuming fulfillment of certain conditions. Therefore the Company will construct the CCDS without knowing beforehand which industrial customers, if any, will be served.

Staff-NWN-CUB-NWIGU-Coos County/1515
Tatom-Henderson-Jenks-Schoenbeck-Whitty/9

Q. What are the expected costs of serving residential, commercial, and industrial customers in Coos County?

A. *Henderson*: By the end of the second year of service, when construction of the intial CCDS will be completed, the cost of serving residential, commercial, and industrial customers in Coos County is estimated to be $2,470,712. Detailed costs are provided in the spreadsheet attached as Exhibit 1516.

Q. What is a reasonable allocation of the costs of the distribution system between industrial customers and all other Coos County customers?

A. *All*: Under the proposal set forth in the Second Stipulation, all sales customers, regardless of class, pay $0.02 per therm toward repayment of the Coos County Share. Transporters on the County pipeline will contribute transportation charges in excess of their volumetric share of pipeline O&M expense. In addition, any transportation customer eligible for a special contract must pay rates that have been approved by the Commission. When the Commission approves such contracts, one factor it will consider is whether the customer is contributing sufficient amounts to fixed costs, including repayment of the Coos County Share. To the extent these contributions have not fully repaid the Coos County Share after the first twenty years of service, NW Natural will calculate the remaining balance and the Commission will establish an appropriate level of surcharge, if one is necessary, to effect repayment. The Parties believe that this general method of cost allocation is reasonable under the circumstances.

Q. Have economic studies been done on the number of residential and commercial customers in Coos County likely to switch to natural gas in the first five years, besides the Forefront Economics study? What is a reasonable assumption for that

switch, given the price of alternative fuels, the cost to customers of new equipment, customer payment for line extensions from the "backbone" distribution system, etc.?

A. *Henderson*: NW Natural has developed its own models and load projections, both in the DR 30 docket and in this case. NW Natural's assumptions for load growth are more conservative than those presented in the Forefront Economics study. Specifically, NW Natural projects a load for residential and commercial customers of 1,326,316 therms in year 1, growing to 7,935,975 therms in year twenty. NW Natural believes its projections constitute reasonable forecasts of residential and commercial load, given factors such as fuel cost, conversion expense, and contributions under Schedule X.

Q. How would the market in Coos County respond to a 2 cent per therm, 3 cent per therm, 5 cent per therm, and 10 cent per therm surcharge on NWN gas sold in Coos County to residential and commercial customers?

A. *All*: The Parties believe the 2-cent-per-therm charge, with a potential adjustment after twenty years, is the appropriate level to balance gas marketing efforts with the repayment mechanism proposed in the Second Stipulation. NW Natural and Coos County believe that a higher initial charge would have an adverse affect on load growth on commercial and residential schedules and could compromise efforts to repay the Coos County Share. Conversely, keeping the charge to Coos County customers at a modest level in the early years may be an important factor in creating a healthy customer base as the system gets established, and a healthier customer base will in turn help accelerate repayment of the Coos County Share.

Q. In the first years of operation, there may not be enough customers to support even half of the cost of the Coos County distribution system. How could rates be designed, and costs accounted for, such that Coos County natural gas customers

eventually pay their share of the costs of the distribution system under the main extension policy?

A. *All*: The Parties believe that the cost-sharing proposal in the Second Stipulation represents the best mechanism for support of the CCDS, consistent with NW Natural's line extension policy.

Q. **What customers will the North Spit spur serve when rates go into effect? If there are no customers served, explain how the line meets the used and useful test under ORS 757.355.**

A. *Henderson*: The status of potential customers on the North Spit is unknown at present. NW Natural plans to include a pipeline to the North Spit in its initial construction of the CCDS because the costs of building the line along with the rest of the system are far less than the costs of building it later, and having the line in place will facilitate NW Natural's efforts to market gas to potential North Spit customers. NW Natural acknowledges that it must demonstrate that the North Spit pipeline is used and useful in order to retain that investment in rate base.

Q. **If NNG builds the distribution system, will it continue to provide propane service to Coos County customers? If yes, how will it price propane?**

A. *Henderson*: NW Natural intends to phase out propane service in Coos County in areas served by the CCDS. The details of that transition are still under review at NW Natural.

Q. **Does this conclude your joint testimony?**

A. Yes.

HARDY MYERS
Attorney General

PETER D. SHEPHERD
Deputy Attorney General

UG 152

DEPARTMENT OF JUSTICE
GENERAL COUNSEL DIVISION

April 10, 2003

RECEIVED
APR 10 2003
Public Utility Commission of Oregon
Administrative Hearings Division

Allan Arlow
Administrative Law Judge
Public Utility Commission of Oregon
550 Capitol Street, NE
Salem, Oregon 97301

Re: *UG 152/Coos County*

Dear Judge Arlow,

Enclosed for filing please find the original and five copies of Exhibit 1516. Exhibit 1516 should be attached to the Joint Testimony submitted by the Parties to the Second Stipulation Relating to the Coos County Distribution System. I inadvertently omitted this exhibit when I filed the Second Stipulation and Joint Testimony yesterday.

Thank you for your attention.

Sincerely,

Stephanie Andrus
Assistant Attorney General
Regulated Utility & Business Section

Enclosure:
cc: UG 152 Service List

DOCKETED

UG 152

UG 152/NWN/1516
Bonnie Tatom,
Dennis L. Henderson,
Bob Jenks,
Donald W. Schoenbeck,
and Nikki Whitty

RECEIVED
APR 10 2003
Public Utility Commission of Oregon
Administrative Hearings Division

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

SECOND STIPULATION CONCERNING THE COOS COUNTY DISTRIBUTION SYSTEM

NW Natural

Exhibit of
Dennis L. Henderson

DOCKETED

April 2003

EXHIBIT 1516

NW Natural
Coos Bay Analysis

		Year 1	Year 2
1	Construction Cost	$7,487,811	$4,512,189
2	Rate Base Gross Plant Only	$3,743,906	$9,743,906
3	Depreciation @ 3 % (1/2 year for incremental)	$112,317	$292,317
4	Rate Base Net Plant Only	$7,375,494	$11,595,366
5	Rate Base - net of depreciation & deferred tax	$6,459,808	$10,067,477
6	Depreciation	$112,317	$292,317
7	Property Taxes	$100,307	$157,697
8	Operations & Maintenance	$715,500	$715,500
	Taxes on Equity Return		
9	State	$36,713	$57,216
10	Federal	$181,840	$283,393
11	Total Taxes	$218,552	$340,609
	Return on Rate Base		
12	Debt	$237,852	$370,687
13	Preferred Equity	$21,800	$33,975
14	Common Equity	$315,902	$492,327
15	Total Return	$575,554	$896,989
16	Subtotal Cost of Service	$1,722,230	$2,403,112
17	Revenue Sensitive Costs	$48,446	$67,600
18	Total Cost of Service	$1,770,677	$2,470,712

By the end of year 2, when the full system will have been built, the cost of serving residendial, commercial and industrial commercial customer in Coos Co. will be $2,470,712.

Any effort to partition the cost of serving customers between the classes quickly becomes complicated by the difficulty of allocating shared costs. Looking only at the cost of meters and services, the investment necessary to serve a residential customer is $671; a commercial meter and service costs $1,540 and the average industrial meter and service costs $10,250.

CERTIFICATE OF SERVICE

I hereby certify that on the 9th day of April 2003, I served EXHIBIT 1516 upon the parties by electronic mail and by regular mail on April 10th, 2003.

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SSA/nal/GENF2374

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2024

Oregon Utility Statistics

Oregon Public Utility Commission

Oregon Public Utility Commission

2024
Oregon Utility Statistics

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Les Perkins, Commissioner
Karin Power, Commissioner

Bryan Conway, Director
Water, Telecom, Safety, and Consumers Program
Caroline Moore, Director
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Oregon Public Utility Commission

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For this report and additional information, visit
www.oregon.gov/puc

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UG 527/CUB/310
Jenks-Dougan/7

Electricity

Foreword to Electric Utilities

Three investor-owned electric utilities operate in Oregon. Investor-owned electric utilities provide service to approximately 74 percent of the customers in the state.

The average annual kilowatt hour (kWh) consumption of residential customers for Oregon operations of investor-owned electric utilities is as follows:

	2024	2023	2022	2021	2020
Investor-Owned Electric Utilities	9,859	10,320	10,606	10,554	10,304

The following types of electric suppliers served electric customers in Oregon on December 31, 2024:

Type of Electricity Supplier	Number	MWh Sales in Oregon (%)[3]	Customers in Oregon (%)[3]
Investor-Owned	3	57.2	74.1
Electricity Service Suppliers (ESS)[1]	6	4.9	< 0.1
Cooperative[2]	19	21.3	10.4
Municipal-Owned[2]	12	8.0	9.7
People's Utility District[2]	6	8.6	5.7

[1] Since March 1, 2002, all retail electricity consumers of Portland General Electric Company and PacifiCorp, except residential consumers, may elect to purchase electricity from an entity other than the distribution utility. (See ORS 757.600 et seq.)
[2] Cooperatives, Municipal-Owned Utilities, and People's Utility Districts (PUDs), are not regulated by the Oregon Public Utility Commission, except for safety, area allocation, transmission lines, and curtailment. Reports submitted by Cooperatives, Municipal-Owned Utilities, and PUDs are not audited by the Commission. Some companies may report duplicate customers. An example of a duplicate is a customer whose household service is billed under a residential rate schedule and whose security lighting outside the home is billed under a lighting schedule. When duplicate customers are known and measurable, they have been footnoted. Summary data are provided for informational purposes only.
[3] Percentages are subject to rounding.

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Clearwater Power Company
Columbia Basin Electric Cooperative, Inc.
Columbia Power Cooperative Association
Columbia Rural Electric Association, Inc.
Consumers Power, Inc.
Coos-Curry Electric Cooperative, Inc.
Douglas Electric Cooperative, Inc.
Harney Electric Cooperative, Inc.
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Lane Electric Cooperative, Inc.
Midstate Electric Cooperative, Inc.

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Investor-Owned Electric Utilities in Oregon

Ten-Year Summary
Selected Statistics

	Oregon Total[A]					Residential Averages in Oregon			
	Revenue From Retail Energy Customers	Energy Sold to Retail Customers (MWh)[B]	Delivery To ESS Customers (MWh)[B]	Average[C] Number of Customers	Average[C] Revenue Per kWh (Cents)	Number of Customers	Revenue Per kWh (Cents)	Per Customer Revenue	Per Customer kWh
2015	$3,053,660,000	31,212,875	1,894,078	1,434,833	9.78	1,248,341	11.55	$1,184	10,253
2016	$3,032,034,287	30,784,510	2,012,115	1,452,375	9.85	1,263,988	11.43	$1,176	10,292
2017	$3,146,019,433	31,636,729	2,321,960	1,469,762	9.94	1,279,266	11.44	$1,240	10,848
2018	$3,055,246,891	30,731,768	2,428,515	1,488,185	9.94	1,295,377	11.63	$1,180	10,151
2019	$3,111,691,988	31,058,126	2,519,939	1,505,111	10.02	1,310,486	11.77	$1,201	10,205
2020	$3,191,040,456	31,085,346	2,502,859	1,525,594	10.27	1,329,436	11.97	$1,233	10,304
2021	$3,344,921,759	32,491,956	2,641,124	1,542,108	10.29	1,344,065	12.12	$1,279	10,554
2022	$3,470,485,565	33,301,046	2,732,314	1,559,109	10.42	1,359,177	12.36	$1,310	10,606
2023	$3,956,697,552	33,730,572	2,688,812	1,571,762	11.73	1,371,170	14.16	$1,461	10,320
2024	$4,573,071,814	33,937,674	2,879,469	1,593,626	13.47	1,391,054	16.64	$1,641	9,859

[A] Oregon Total excludes Sales for Resale and Other Electric Revenue.
[B] 1 Megawatt hour (MWh) = 1,000 Kilowatt hours (kWh).
[C] These figures exclude ESS customers.

Idaho Power Company – Oregon Electric

Ten-Year Summary
Selected Statistics

	Oregon Total[A]					Residential Averages in Oregon			
	Revenue From Retail Energy Customers	Energy Sold to Retail Customers (MWh)[B]	Delivery To ESS Customers (MWh)[B]	Average Number of Customers	Average Revenue Per kWh (Cents)	Number of Customers	Revenue Per kWh (Cents)	Per Customer Revenue	Per Customer kWh
2015	$52,335,507	654,028	N/A	18,706	8.00	13,369	10.08	$1,306	12,954
2016	$53,271,855	667,363	N/A	18,848	7.98	13,396	10.08	$1,349	13,386
2017	$53,834,004	682,167	N/A	18,937	7.89	13,423	9.99	$1,437	14,388
2018	$55,724,734	678,532	N/A	19,054	8.21	13,435	10.16	$1,337	13,163
2019	$51,990,825	664,771	N/A	19,259	7.82	13,543	9.48	$1,261	13,300
2020	$51,246,472	668,084	N/A	19,403	7.67	13,628	9.19	$1,228	13,364
2021	$54,337,652	685,578	N/A	19,586	7.93	13,742	9.43	$1,287	13,653
2022	$60,578,416	695,393	N/A	19,831	8.71	13,883	10.24	$1,485	14,511
2023	$63,052,615	649,616	N/A	20,035	9.71	14,012	11.17	$1,521	13,610
2024	$64,469,425	673,939	N/A	20,195	9.57	14,098	11.29	$1,493	13,226

[A] Oregon Total excludes Sales for Resale and Other Electric Revenue.
[B] 1 Megawatt hour (MWh) = 1,000 Kilowatt hours (kWh).

PacifiCorp – Oregon Electric

Ten-Year Summary
Selected Statistics

	Oregon Total[A]					Residential Averages in Oregon			
	Revenue From Retail Energy Customers	Energy Sold to Retail Customers (MWh)[B]	Delivery To ESS Customers (MWh)[B]	Average[C] Number of Customers	Average[C] Revenue Per kWh (Cents)	Number of Customers	Revenue Per kWh (Cents)	Per Customer Revenue	Per Customer kWh
2015	$1,265,741,624	12,862,461	208,372	567,603	9.84	492,505	11.60	$1,249	10,763
2016	$1,274,834,790	12,868,974	289,867	574,131	9.91	498,227	11.50	$1,266	11,003
2017	$1,317,990,019	13,200,282	358,780	580,492	9.98	503,632	11.50	$1,325	11,525
2018	$1,239,371,197	12,867,234	393,021	587,365	9.63	509,553	11.17	$1,218	10,904
2019	$1,270,397,389	13,088,664	364,384	595,833	9.71	517,270	11.17	$1,236	11,062
2020	$1,293,711,531	12,993,459	383,647	603,954	9.96	524,689	11.33	$1,244	10,978
2021	$1,251,099,183	13,510,324	404,703	610,313	9.26	529,951	10.71	$1,217	11,359
2022	$1,264,763,577	13,700,592	406,837	616,834	9.23	535,721	10.73	$1,227	11,434
2023	$1,513,650,640	13,949,228	396,602	622,868	10.85	541,238	12.88	$1,429	11,099
2024	$1,725,573,161	13,991,113	455,559	629,487	12.33	547,235	14.74	$1,562	10,592

[A] Oregon Total excludes Sales for Resale and Other Electric Revenue.
[B] 1 Megawatt hour (MWh) = 1,000 Kilowatt hours (kWh).
[C] These figures exclude ESS customers.

Portland General Electric Company

Ten-Year Summary
Selected Statistics

	Oregon Total[A]					Residential Averages in Oregon			
	Revenue From Retail Energy Customers	Energy Sold to Retail Customers (MWh)[B]	Delivery to ESS Customers (MWh)[B]	Average[C] Number of Customers	Average[C] Revenue Per kWh (Cents)	Number of Customers	Revenue Per kWh (Cents)	Per Customer Revenue	Per Customer kWh
2015	$1,735,582,869	17,696,386	1,685,706	848,524	9.81	742,467	11.55	$1,139	9,866
2016	$1,703,927,642	17,248,173	1,722,248	859,396	9.88	752,365	11.40	$1,114	9,766
2017	$1,774,195,410	17,754,280	1,963,180	870,333	9.99	762,211	11.42	$1,181	10,338
2018	$1,760,150,960	17,186,002	2,035,494	881,766	10.24	772,389	12.01	$1,153	9,601
2019	$1,789,303,774	17,304,691	2,155,555	890,019	10.34	779,673	12.28	$1,177	9,582
2020	$1,846,082,453	17,423,803	2,119,212	902,237	10.60	791,119	12.50	$1,226	9,804
2021	$2,039,484,924	18,296,054	2,236,421	912,209	11.15	800,372	13.24	$1,320	9,968
2022	$2,145,143,572	18,905,061	2,325,477	922,444	11.35	809,573	13.64	$1,363	9,991
2023	$2,379,994,297	19,131,728	2,292,210	928,859	12.44	815,920	15.20	$1,481	9,746
2024	$2,783,029,228	19,272,622	2,423,910	943,944	14.44	829,721	18.19	$1,695	9,318

[A] Oregon Total excludes Sales for Resale and Other Electric Revenue.
[B] 1 Megawatt hour (MWh) = 1,000 Kilowatt hours (kWh).
[C] These figures exclude ESS customers.

2024 MWh Sales to Ultimate Customers[A][B]

Oregon

	MWh Sales	Percent of MWh Sales	Average No. of Customers
Investor-Owned Utilities:			
Idaho Power	673,939	1.1%	20,195
PacifiCorp	13,991,113	23.6%	629,487
Portland General Electric	19,272,622	32.5%	943,944
Total	**33,937,674**	**57.2%**	**1,593,626**
Total Electricity Service Suppliers (ESS)	**2,879,469**	**4.9%**	**58**
Cooperatives:			
Blachly-Lane County	186,299	0.31%	3,681
Central Electric	816,846	1.38%	38,864
Clear Water Power	1,794	0.00%	177
Columbia Basin Electric	127,509	0.21%	4,012
Columbia Power	25,504	0.04%	2,017
Columbia Rural Electric	6,089	0.01%	128
Consumers Power, Inc.	410,789	0.69%	23,769
Coos-Curry Electric	326,900	0.55%	18,525
Douglas Electric	153,754	0.26%	10,632
Harney Electric	101,325	0.17%	2,478
Hood River Electric	130,124	0.22%	4,015
Lane Electric	234,043	0.39%	13,648
Midstate Electric	453,216	0.76%	21,517
Oregon Trail Electric	675,166	1.14%	31,813
Salem Electric	317,801	0.54%	20,845
Surprise Valley Electrification	38,836	0.07%	1,971
Umatilla Electric	8,431,930	14.22%	16,646
Wasco Electric	109,915	0.19%	4,749
West Oregon	69,432	0.12%	4,671
Total	**12,617,270**	**21.3%**	**224,158**

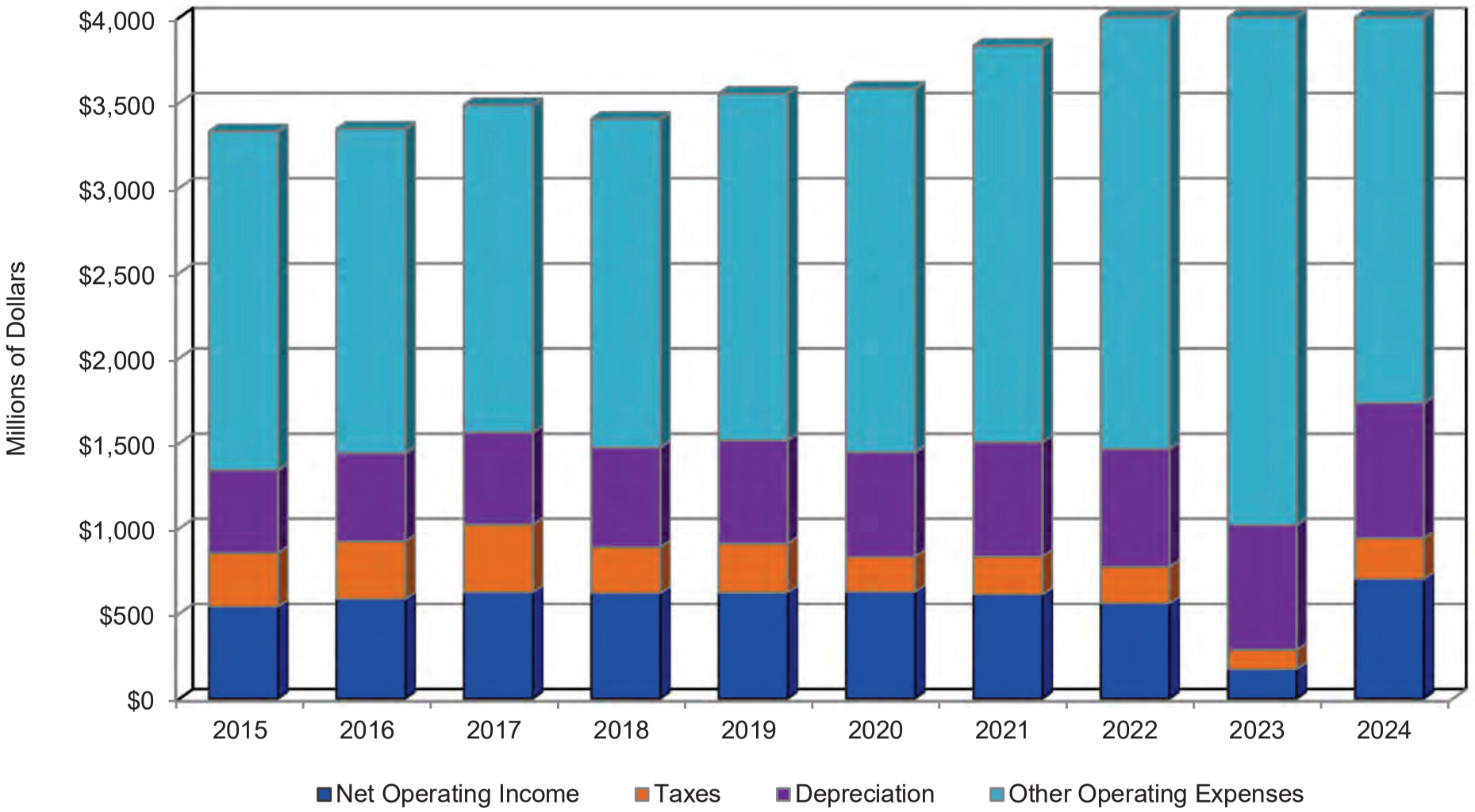
	MWh Sales	Percent of MWh Sales	Average No. of Customers
Municipal-Owned Utilities:			
Ashland	162,894	0.27%	12,204
Bandon	67,727	0.11%	4,843
Canby	195,039	0.33%	8,603
Cascade Locks	41,396	0.07%	1,789
Drain	16,193	0.03%	772
Eugene	2,275,859	3.84%	100,487
Forest Grove	263,919	0.45%	11,316
Hermiston	107,047	0.18%	5,604
McMinnville	726,199	1.22%	20,232
Milton-Freewater	88,122	0.15%	5,057
Monmouth	75,774	0.13%	4,936
Springfield	723,508	1.22%	33,287
Total	**4,743,677**	**8.0%**	**209,130**
People's Utility Districts:			
Central Lincoln	1,194,702	2.01%	41,527
Clatskanie	965,617	1.63%	4,308
Columbia River	475,131	0.80%	20,817
Emerald	473,622	0.80%	22,844
Northern Wasco Co.	1,530,602	2.58%	10,675
Tillamook	489,573	0.83%	22,460
Total	**5,129,247**	**8.6%**	**122,631**
Total Oregon	**59,307,336**	**100%**	**2,149,603**

[A] Ultimate Customer Totals exclude Sales for Resale.
[B] Percentages and totals are subject to rounding.

Investor-Owned Electric Utilities in Oregon

Ten-Year Summary

Distribution of Operating Revenues[A]

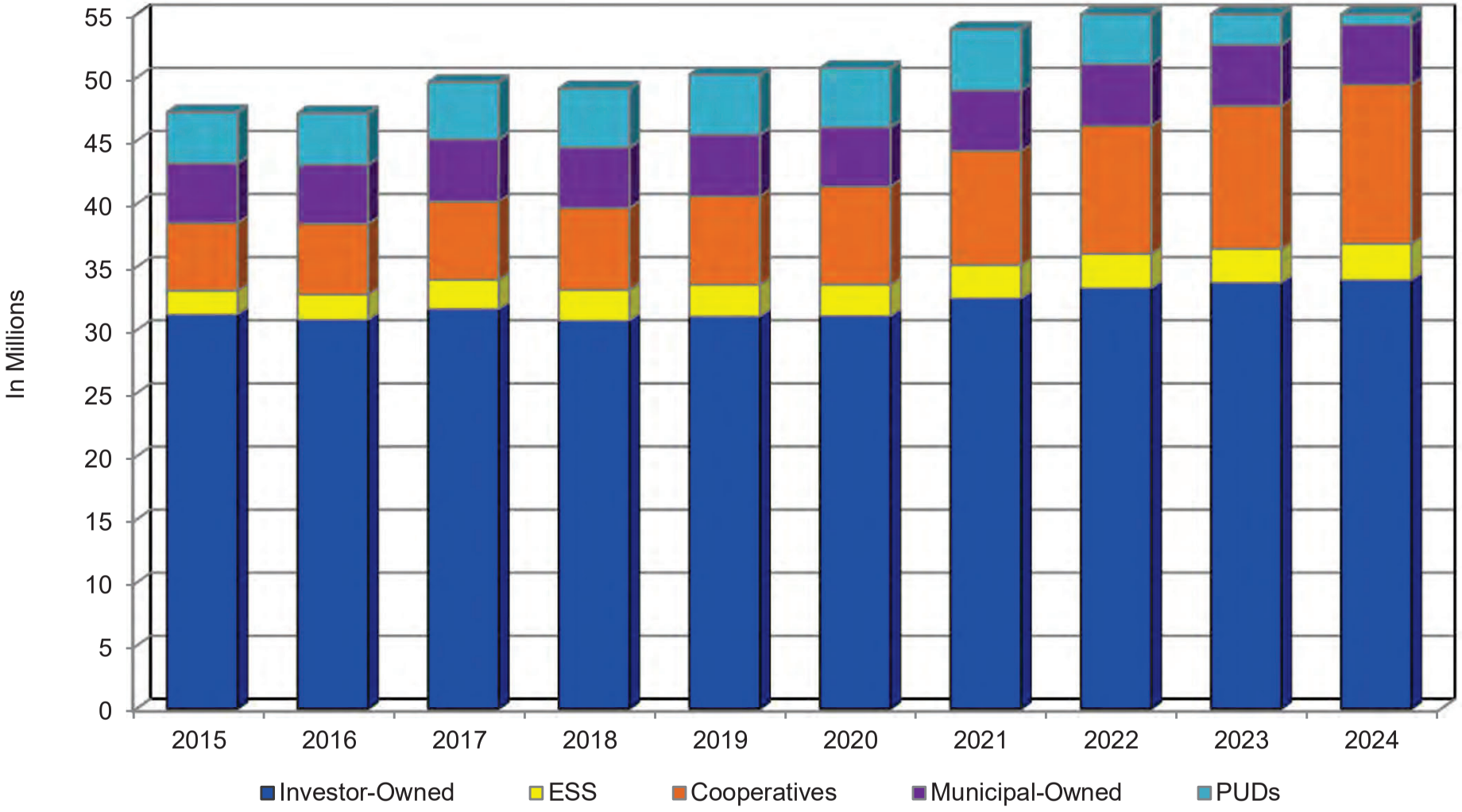


[A] Operating Revenues include revenue from Ultimate Customers, Sales for Resale, and Other Electric Operations.

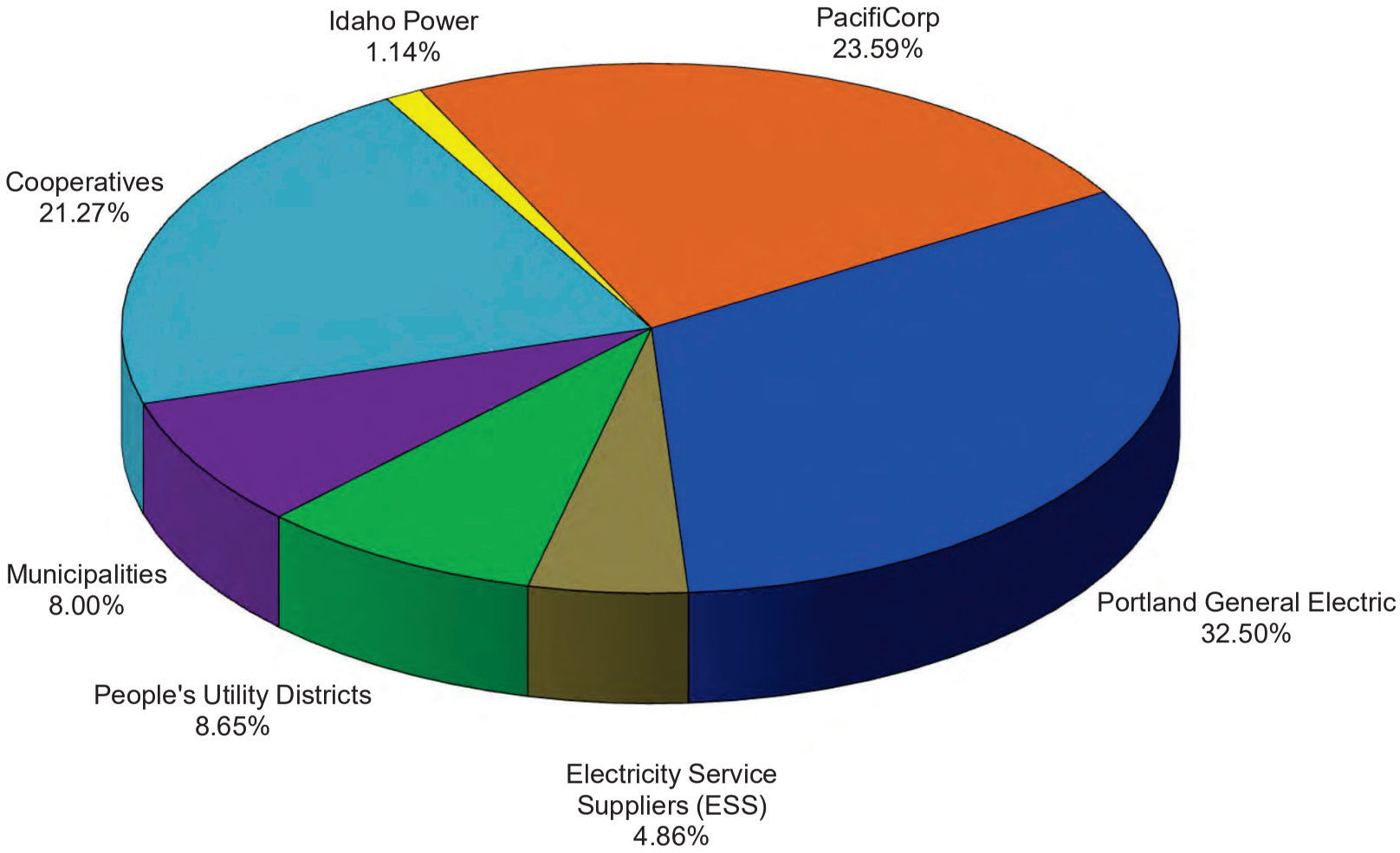
Electric Suppliers in Oregon

Ten-Year Summary

Total Sales to Ultimate Customers (MWh)



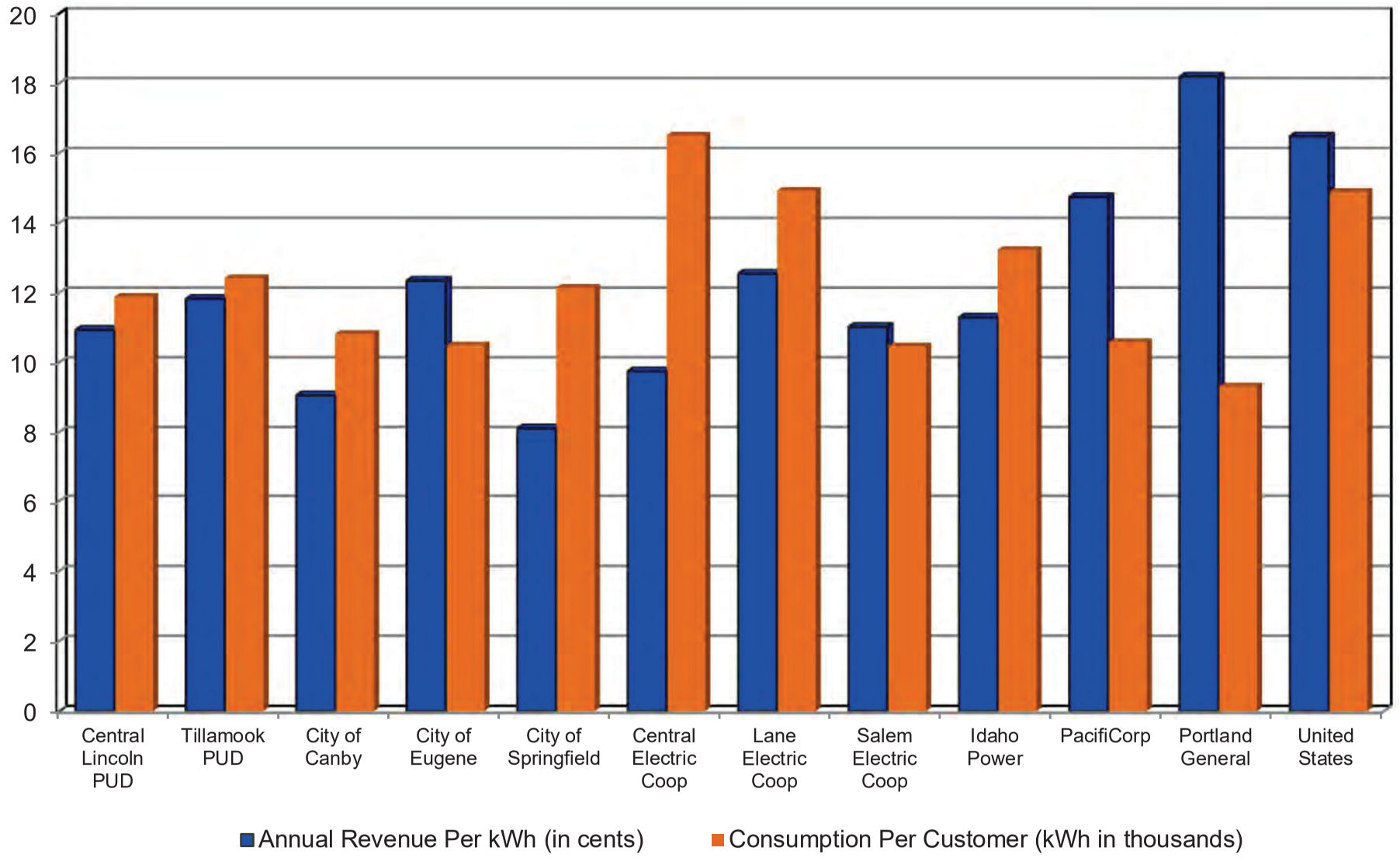
Electric Utilities – Total Oregon
Sales to Ultimate Customers During 2024 (MWh)[A]



[A] Percentages are subject to rounding.

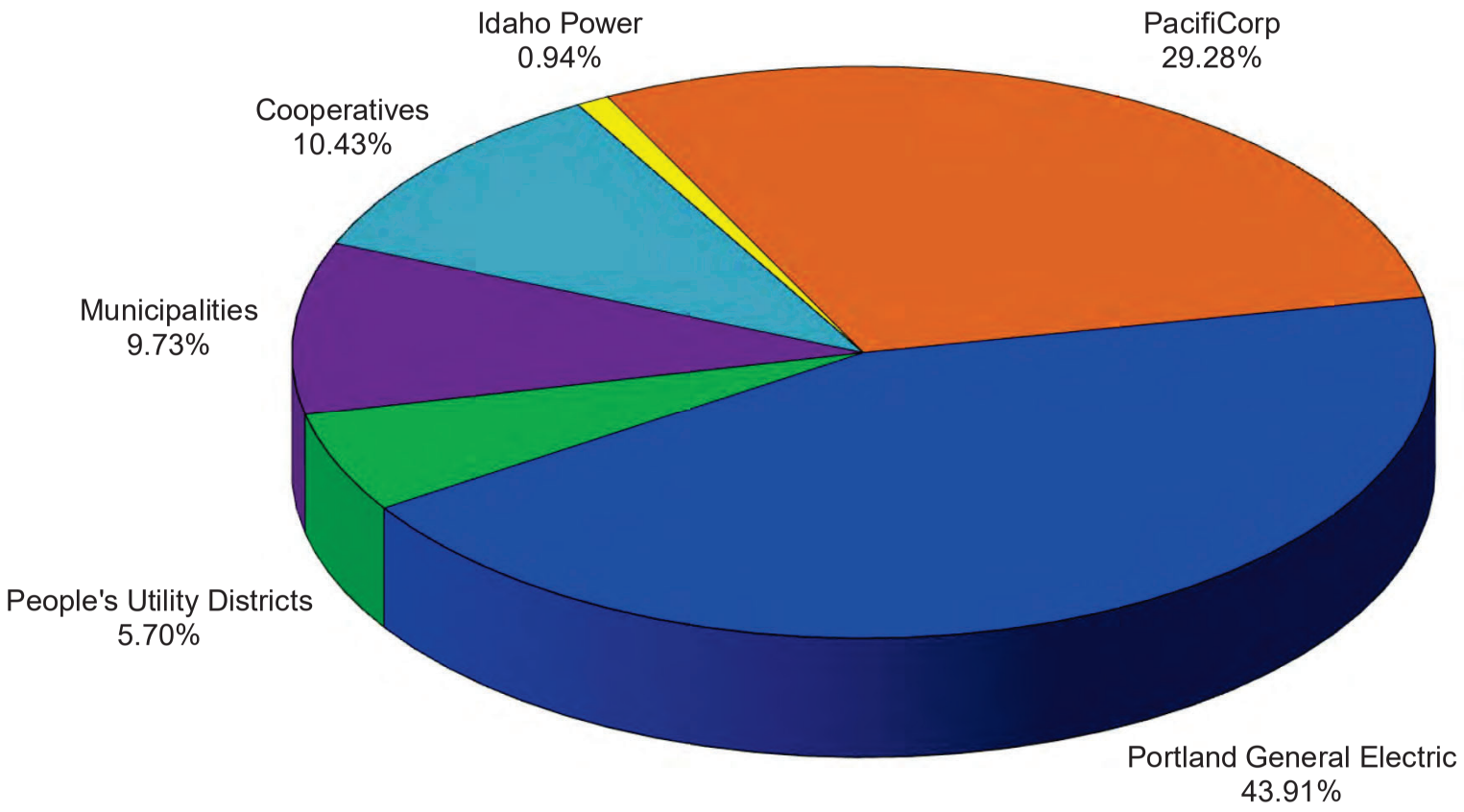
Selected Electric Utilities in Oregon and United States Averages[A]

Residential Averages for 2024



[A] United States data for residential averages is from the Energy Information Administration, Department of Energy.

Electric Utilities – Total Oregon
Customers in Oregon for 2024[A][B]



[A] ESS customers are less than 1% of total Oregon customers.
[B] Percentages are subject to rounding.

Investor-Owned Electric Utilities in Oregon

Balance Sheet – Total System

Year Ending December 31, 2024

	Idaho Power	PacifiCorp	Portland General Electric	Investor-Owned Electric Utilities
ASSETS AND OTHER DEBITS				
Utility Plant	$7,975,277,159	$38,155,394,721	$15,111,925,280	$61,242,597,160
Construction Work in Progress	1,245,682,478	3,480,932,688	569,951,129	5,296,566,295
Less: Depreciation & Amortization Reserve	2,881,559,900	13,997,879,081	6,196,192,797	23,075,631,778
Net Utility Plant	$6,339,399,737	$27,638,448,328	$9,485,683,612	$43,463,531,677
Other Property & Investments	102,833,298	414,863,787	173,960,721	691,657,806
Current & Accrued Assets	718,832,041	2,417,267,430	840,131,761	3,976,231,232
Deferred Debits	1,980,684,232	4,070,148,225	1,525,391,618	7,576,224,075
Total Assets & Other Debits	$9,141,749,308	$34,540,727,770	$12,025,167,712	$55,707,644,790
LIABILITIES AND OTHER CREDITS				
Common Stock	$97,877,030	$3,417,945,896	$2,122,277,163	$5,638,100,089
Preferred Stock	0	2,397,600	0	2,397,600
Premium (Less Disc.) on Capital Stock	912,257,435	0	0	912,257,435
Other Paid-in Capital	0	1,102,063,956	18,789,718	1,120,853,674
Installments Received on Capital Stock	0	0	0	0
Less: Capital Stock Expense	(2,096,925)	(41,101,061)	(23,113,532)	(66,311,518)
Retained Earnings	2,074,237,215	5,985,858,857	1,676,875,055	9,736,971,127
Unappropriated Undist. Sub. Earnings	21,913,594	54,269,402	8,706,023	84,889,019
Less: Reacquired Capital Stock	0	0	0	0
Accumulated Other Comprehensive Income	(13,592,234)	(9,115,257)	(3,855,949)	(26,563,440)
Total Proprietary Capital	$3,090,596,115	$10,512,319,393	$3,799,678,478	$17,402,593,986
Long-Term Debt	3,097,335,606	13,665,642,696	4,538,518,926	21,301,497,228
Other Noncurrent Liabilities	484,335,870	1,841,089,392	1,203,672,521	3,529,097,783
Current & Accrued Liabilities	640,380,201	2,538,015,659	917,457,734	4,095,853,594
Customer Advances for Construction	58,546,387	308,544,692	605,021	367,696,100
Accumulated Deferred Investment Tax Cr.	230,322,101	10,431,425	60,671,318	301,424,844
Other Deferred Credits	44,578,395	346,062,811	27,080,559	417,721,765
Other Regulatory Liabilities	336,880,879	1,096,048,745	320,924,678	1,753,854,302
Unamortized Gain on Required Debt	0	0	0	0
Accumulated Deferred Income Taxes	1,158,773,754	4,222,572,957	1,156,558,477	6,537,905,188
Total Liabilities & Other Credits	$9,141,749,308	$34,540,727,770	$12,025,167,712	$55,707,644,790

Investor-Owned Electric Utilities in Oregon

Income Statement – Total System

Year Ending December 31, 2024

	Idaho Power	PacifiCorp	Portland General Electric	Investor-Owned Electric Utilities
NET INCOME				
Operating Revenues	$1,818,832,846	$6,587,229,882	$3,460,714,742	$11,866,777,470
Operation & Maintenance Expenses	$1,253,865,960	$4,705,045,503	$2,278,254,387	$8,237,165,850
Depreciation & Amortization Expenses	222,373,733	1,115,516,236	487,356,197	1,825,246,166
Taxes Other Than Income	21,738,967	229,276,961	178,176,421	429,192,349
Income Taxes	34,677,769	(279,595,039)	37,375,142	(207,542,128)
Other Operating Expenses	(750,567)	(18,440)	3,163,181	2,394,174
Total Operating Expenses	$1,531,905,862	$5,770,225,221	$2,984,325,328	$10,286,456,411
Net Operating Income	$286,926,984	$817,004,661	$476,389,414	$1,580,321,059
Net Other Income & Deductions	129,194,254	356,498,506	31,574,595	517,267,355
Income Before Interest Charges	$416,121,238	$1,173,503,167	$507,964,009	$2,097,588,414
Interest Charges	107,731,791	514,724,229	176,314,451	798,770,471
AFUDC - Credit	27,784,737	119,854,967	15,344,389	162,984,093
Income Before Extraordinary Items	$280,604,710	$538,923,971	$316,305,169	$1,135,833,850
Extraordinary Items	0	0	0	0
Net Income	$280,604,710	$538,923,971	$316,305,169	$1,135,833,850
RETAINED EARNINGS				
Balance, January 1	$1,978,045,675	$5,436,966,702	$1,572,571,905	$8,987,584,282
Net Income	280,604,709	538,923,971	316,305,169	1,135,833,849
Other Credits	0	0	0	0
Dividends	(175,772,681)	(161,902)	(207,148,789)	(383,083,372)
Other Debits/Charges	0	0	0	0
Appropriated Retained Earnings	13,273,106	64,399,488	3,852,793	81,525,387
Balance, December 31	$2,096,150,809	$6,040,128,259	$1,685,581,078	$9,821,860,146

Investor-Owned Electric Utilities in Oregon

Financial Data – Oregon and Total System

Year Ending December 31, 2024

	Idaho Power		PacifiCorp		Portland General Electric	Investor-Owned Electric Utilities
	Oregon	System	Oregon	System	Oregon	Oregon
OPERATING REVENUES						
Residential	$21,052,037	$700,402,010	$854,617,110	$2,474,881,031	$1,406,370,635	$2,282,039,782
Commercial & Industrial	43,261,272	856,498,358	865,341,922	3,675,466,697	1,362,354,387 [E]	2,270,957,581
Public Street and Highway Lighting	156,116	4,349,086	5,614,129	16,088,695	14,304,206	20,074,451
Other Public Authorities	0	0	0	0	0	0
Revenue from Retail Energy Customers	$64,469,425 [B]	$1,561,249,454	$1,725,573,161	$6,166,436,423	$2,783,029,228	$4,573,071,814
Sales for Resale	5,948,366	142,669,958	28,047,386	123,793,686	588,094,149	622,089,901
Total Revenue from Electric Sales	$70,417,791	$1,703,919,412 [C]	$1,753,620,547	$6,290,230,109 [D]	$3,371,123,377 [F]	$5,195,161,715
(Less) Provision for Rate Refunds	334,507	(8,225,395)	0	0	36,929,618	37,264,125
Other Electric Revenue	5,277,304	123,138,829	73,620,522	296,999,773	126,520,982	205,418,808
Total Operating Revenue	$76,029,602	$1,818,832,846	$1,827,241,069	$6,587,229,882	$3,460,714,741	$5,363,316,398
Revenue from ESS[A] Deliveries	N/A	N/A	$10,001,110	N/A	$31,947,329	$41,948,439
OPERATING EXPENSES						
Production	$33,788,079	$855,896,983	$810,089,473	$3,082,649,481	$1,513,877,088	$2,357,754,640
Transmission	1,578,048	39,491,410	71,012,719	272,278,523	158,804,678	231,395,445
Distribution	4,749,343	81,894,482	182,933,405	400,265,008	228,327,958	416,010,706
Customer Accounts	1,180,716	24,946,138	28,141,891	89,716,329	84,963,822	114,286,429
Customer Service & Information	1,960,902	39,798,601	5,148,869	203,222,486	28,883,061	35,992,832
Administrative & General	8,793,793	211,838,351	193,657,449	656,913,676	263,397,780	465,849,022
Total Operating Expenses	$52,050,881	$1,253,865,965	$1,290,983,806	$4,705,045,503	$2,278,254,387	$3,621,289,074
OTHER REVENUE DEDUCTIONS						
Depreciation & Amortization	$9,146,853	$222,373,733	$296,976,962	$1,115,516,236	$487,356,197	$793,480,012
Taxes	4,024,024	50,833,507	26,694,757	(61,760,517)	210,605,293	241,324,074
Miscellaneous Debits & Credits	0	5,583,229	0	11,442,439	4,946,270	4,946,270
Net Gains (Loss) from Disposition of Utility Plant	0	(750,567)	(737,005)	(18,440)	3,163,181	2,426,176
Total Revenue Deductions	$13,170,877	$278,039,902	$322,934,714	$1,065,179,718	$706,070,941	$1,042,176,532
Total Expenses and Deductions	$65,221,758	$1,531,905,867	$1,613,918,520	$5,770,225,221	$2,984,325,328	$4,663,465,606
NET OPERATING INCOME (or Loss)	$10,807,844	$286,926,979	$213,322,549	$817,004,661	$476,389,413	$699,850,792

[A] ESS - Electricity Service Suppliers.

[B] Includes $142,473 of unbilled revenues.

[C] Includes $1,191,815 of unbilled revenues.

[D] Includes $328,006,000 of unbilled revenues.

[E] Includes $31,947,329 in revenue related to the delivery of 2,423,910 megawatt hours ESS customers.

[F] Includes $41,005,000 of unbilled revenues.

Investor-Owned Electric Utilities in Oregon

Source and Disposition of Electric Energy

Oregon and Total System (MWh)[A]

Year Ending December 31, 2024

	Idaho Power		PacifiCorp		Portland General Electric	Investor-Owned Electric Utilities
	Oregon	System	Oregon	System	Oregon	Oregon
GENERATION (MWh)						
Steam	0	2,473,955	6,427,661	26,066,582	1,910,235	8,337,896
Hydro	2,890,793	7,202,486	638,910	2,588,799	1,266,720	4,796,423
Other	0	3,843,475	4,020,013	16,304,887	13,873,009	17,893,022
Total Generation	2,890,793	13,519,916	11,086,584	44,960,268	17,049,964	31,027,341
PURCHASED ENERGY	[C]	6,560,359	5,164,226	20,246,502	13,893,153	19,057,379
INTERCHANGES – NET	[C]	(151,301)	96,961	379,772	7,057	104,018
Grand Total Available	[C]	19,928,974	16,347,771	65,586,542	30,950,174	50,188,738 [K]
SALES (MWh)						
Residential	186,456	5,963,609	5,796,437	18,252,979	7,731,594	13,714,487
Commercial & Industrial	487,126	9,982,814	8,164,209	40,116,438	11,498,403	20,149,738
Public Street and Highway Lighting	357	24,611	30,467	105,737	42,625	73,449
Other Public Authorities	0	0	0	0	0	0
Sales to Retail Energy Customers	673,939 [D]	15,971,034	13,991,113 [G]	58,475,154	19,272,622	33,937,674
Sales for Resale	117,468	2,817,443	510,156	2,279,646	10,305,039	10,932,663
Total All Sales	791,407	18,788,477 [F]	14,501,269	60,754,800 [H]	29,577,661 [I]	44,870,337
Percentage of Oregon Sales	4%	N/A	24%	N/A	100%	N/A
ENERGY NOT REPORTED AS SOLD						
Furnished Without Charge	[C]	0	0	0	0	0
Used by Company	[C]	0	16,605	112,074	27,222	43,827
Total Accounted For	791,407	18,788,477	14,517,874	60,866,874	29,604,883	44,914,164
BALANCE LOST	[C]	1,140,497	1,829,897	4,719,668	1,345,291	3,175,188
Grand Total Disposition	[C]	19,928,974	16,347,771	65,586,542	30,950,174	47,297,945 [J]
ESS[B] Deliveries	N/A	N/A	455,559	N/A	2,423,910	2,879,469
GENERATION CAPACITY (Total Installed Year End)						
Steam	0	920,186	1,654,812	6,326,290	311,200	1,966,012
Hydro	601,076	1,818,489	263,256	1,006,420	924,200	1,788,532
Other	0	767,153	750,022	2,867,310	2,077,900	2,827,922
Total Installed (kW)	601,076 [E]	3,505,828	2,668,091	10,200,020	3,313,300	6,582,467

[A] 1 Megawatt hour (MWh) = 1,000 Kilowatt hours (kWh).
[B] ESS - Electricity Service Suppliers.
[C] Data unavailable.
[D] Includes 1,211 MWh relating to unbilled revenues.
[E] Oregon situs.
[F] Includes 1,308 MWh relating to unbilled revenues.
[G] Includes 779,817,333 MWh relating to unbilled revenues.
[H] Includes 3,181,831 MWh relating to unbilled revenues.
[I] Includes 219,530 MWh relating to unbilled revenues.
[J] Grand Total Dispostion does not equal Grand Total Available due to unavailable data from Idaho Power.

Investor-Owned Electric Utilities in Oregon

Sales Statistics – Oregon and Total System

Year Ending December 31, 2024

	Idaho Power		PacifiCorp		Portland General Electric	Investor-Owned Electric Utilities
	Oregon	System	Oregon	System	Oregon	Oregon
AVERAGE NUMBER OF CUSTOMERS						
Residential	14,098	539,849	547,235	1,837,507	829,721	1,391,054
Commercial & Industrial	6,059	96,786	81,801	263,363	114,005	201,865
Public Street and Highway Lighting	38	4,931	451	3,180	218	707
Other Public Authorities	0	0	0	0	0	0
Total	20,195	641,566	629,487 [A]	2,104,050	943,944 [A]	1,593,626 [A]
AVERAGE REVENUE PER kWh SOLD (Cents)						
Residential	11.29	11.74	14.74	13.56	18.19	16.64
Commercial & Industrial	8.88	8.58	10.60	9.16	11.85	11.27
Public Street and Highway Lighting	43.73	17.67	18.43	15.22	33.56	27.33
Other Public Authorities	0.00	0.00	0.00	0.00	0.00	0.00
Total Sales - Retail Energy Customers	9.57	9.78	12.33 [B]	10.55	14.44 [B]	13.47 [B]
Sales for Resale	5.06	5.06	5.50	5.43	5.71	5.69
Total	8.90	9.07	12.09	10.35	11.40	11.58
RESIDENTIAL AVERAGE PER CUSTOMER						
Revenue	$1,493	$1,297	$1,562	$1,347	$1,695	$1,641
Sales (kWh)	13,226	11,047	10,592	9,934	9,318	9,859

[A] Oregon excludes ESS (Electricity Service Suppliers) customers.
[B] Oregon excludes revenues from ESS customers and MWh of ESS deliveries.

Electric Cooperatives in Oregon

Operating Revenues, Expenses, and Income

Year Ending December 31, 2024

	Blachly-Lane	Central Electric	Clearwater Power	Columbia Basin Electric	Columbia Power	Columbia Rural Electric
OPERATING REVENUES						
Residential	$7,673,553	$55,629,608	$186,356	$4,803,026	$2,141,569	$113,066
Commercial & Industrial	8,912,387	14,194,594	53,560	4,505,300	563,292	124,993
Public Street and Highway Lighting	9,811	73,767	0	60,709	16,836	0
Other Public Authorities	0	0	0	0	0	0
Interdepartmental Sales	0	0	0	0	0	0
Irrigation Sales	98,633	4,369,207	2,331	2,296,815	459,075	376,108
Other Sales to Ultimate Customers	0	0	0	0	0	0
Total Revenue from Ultimate Customers	$16,694,384	$74,267,176	$242,246	$11,665,850	$3,180,772	$614,167
Sales for Resale	0	0	0	0	0	359,235
Total Revenue – Sales of Electric Energy	$16,694,384	$74,267,176	$242,246	$11,665,850	$3,180,772	$973,402
Miscellaneous Revenues	(6,780)	543,456	11,389	202,533	0	0
Total Operating Revenues	$16,687,604	$74,810,632	$253,636	$11,868,383	$3,180,772	$973,402
OPERATING EXPENSES						
Production	$0	$0	$0	$0	$0	$0
Purchase	8,201,999	37,503,902	61,642	5,784,554	817,204	293,074 [A]
Transmission	0	195,367	0	25,904	158,409	0
Distribution	2,616,667	5,539,107	57,777	2,378,801	1,927,224	123,351
Customer Accounts	501,574	2,389,662	6,113	442,924	298,315	16,265
Customer Service & Information	185,728	618,432	4,386	63,287	0	3,428
Administrative & General	2,125,475	8,691,058	29,885	1,046,514	477,902	93,791
Total Operating Expenses	$13,631,443	$54,937,528	$159,803	$9,741,984	$3,679,054	$529,908
OTHER REVENUE DEDUCTIONS						
Depreciation & Amortization Expenses	$1,188,133	$8,765,118	$30,491	$1,345,569	$377,749	$92,224
Taxes	416,509	2,907,479	7,680	251,520	112,419	19,416
Other Expenses	838,538	2,522,281	12,744	287,281	501,863	74,164
Non-operating (Gain) or Loss	0	(2,407,263)	0	(57,450)	(38,578)	(69,682)
Total Other Revenue Deductions	$2,443,180	$11,787,615	$50,915	$1,826,920	$953,453	$116,122
Net Operating Income or (Loss)	$612,981	$8,085,489	$42,918	$299,479	($1,451,735)	$327,372
Fixed Capital	$51,061,325	$318,907,257	$1,618,475	$42,076,555	$34,470,759	$2,261,962
Depreciation Reserve	18,227,117	137,110,156	430,651	22,708,756	15,626,406	920,717

[A] Includes the transmission part of the bill.

Electric Cooperatives in Oregon

Operating Revenues, Expenses, and Income

Year Ending December 31, 2024

	Consumers Power	Coos-Curry Electric	Douglas Electric	Harney Electric	Hood River Electric	Lane Electric
OPERATING REVENUES						
Residential	$34,405,675	$23,980,857	$16,322,941	$1,728,394	$4,968,634	$23,234,984
Commercial & Industrial	15,882,949	15,084,067	2,856,654	1,172,010	4,761,935	4,998,981
Public Street and Highway Lighting	150,053	167,080	10,385	0	0	86,596
Other Public Authorities	0	0	0	0	0	0
Interdepartmental Sales	0	0	0	0	0	0
Irrigation Sales	824,223	806,454	189,714	4,293,978	203,514	11,870
Other Sales to Ultimate Customers	0	0	0	0	0	0
Total Revenue from Ultimate Customers	$51,262,900	$40,038,458	$19,379,694	$7,194,382	$9,934,083	$28,332,431
Sales for Resale	0	0	0	0	0	0
Total Revenue – Sales of Electric Energy	$51,262,900	$40,038,458	$19,379,694	$7,194,382	$9,934,083	$28,332,431
Miscellaneous Revenues	385,734	1,608,546	258,412	22,820	0	860,081
Total Operating Revenues	$51,648,634	$41,647,004	$19,638,106	$7,217,202	$9,934,083	$29,192,512
OPERATING EXPENSES						
Production	$0	$0	$0	$0	$0	$0
Purchase	18,175,080	13,418,403	6,476,182	3,396,963	5,838,173	9,193,603
Transmission	534,801	163,366	5,792	657,140	699,764	6,032
Distribution	12,553,870	12,236,935	5,357,403	1,558,077	1,400,371	7,050,328
Customer Accounts	1,143,302	1,600,986	424,996	80,000	227,715	1,201,298
Customer Service & Information	921,473	1,408,245	236,579	98,509	0	833,448
Administrative & General	3,610,572	3,051,473	2,840,469	251,295	0	3,679,793
Total Operating Expenses	$36,939,098	$31,879,407	$15,341,421	$6,041,984	$8,166,024	$21,964,502
OTHER REVENUE DEDUCTIONS						
Depreciation & Amortization Expenses	$5,342,360	$4,603,562	$2,399,000	$1,145,357	$735,882	$3,056,539
Taxes	1,743,088	1,225,184	728,028	195,593	124,500	1,054,487
Other Expenses	3,065,624	2,839,827	1,165,198	141,536	370,991	1,633,794
Non-operating (Gain) or Loss	(534,919)	5,801,345	0	(533,477)	(1,138,589)	(231,956)
Total Other Revenue Deductions	$9,616,153	$14,469,918	$4,292,226	$949,009	$92,784	$5,512,864
Net Operating Income or (Loss)	$5,093,383	($4,702,321)	$4,459	$226,209	$1,675,275	$1,715,146
Fixed Capital	$219,254,292	$161,231,721	$86,779,230	$40,129,342	$20,291,639	$105,473,450
Depreciation Reserve	90,859,403	66,672,183	36,187,027	13,100,705	10,462,832	35,875,685

Electric Cooperatives in Oregon

Operating Revenues, Expenses, and Income

Year Ending December 31, 2024

	Midstate Electric	Oregon Trail Electric	Salem Electric	Surprise Valley Electrification	Umatilla Electric	Wasco Electric	West Oregon Electric
OPERATING REVENUES							
Residential	$30,321,809	$31,515,368	$21,210,709	$2,152,746	$17,894,844	$7,613,283	$11,810,348
Commercial & Industrial	10,686,077	22,074,129	12,026,845	982,331	540,855,033	4,097,737	3,203,876
Public Street and Highway Lighting	1,440	343,399	280,500	4,058	85,280	23,174	47,157
Other Public Authorities	0	0	0	0	0	0	0
Interdepartmental Sales	0	0	0	0	0	0	4,600
Irrigation Sales	3,793,347	4,117,880	0	1,734,991	21,819,123	1,632,520	10,632
Other Sales to Ultimate Customers	0	0	0	0	0	0	0
Total Revenue from Ultimate Customers	$44,802,673	$58,050,776	$33,518,054	$4,874,126	$580,654,279	$13,366,715	$15,076,613
Sales for Resale	0	0	0	0	0	0	0
Total Revenue – Sales of Electric Energy	$44,802,673	$58,050,776	$33,518,054	$4,874,126	$580,654,279	$13,366,715	$15,076,613
Miscellaneous Revenues	(324,844)	922,303	254,619	11,273	4,597,926	489,062	67,079
Total Operating Revenues	$44,477,829	$58,973,079	$33,772,673	$4,885,399	$585,252,205	$13,855,777	$15,143,692
OPERATING EXPENSES							
Production	$0	$0	$0	$0	$8,763	$0	$0
Purchase	18,853,770	25,752,993	11,558,765	1,292,902	523,429,122	4,275,903	2,813,337
Transmission	8,271	232,483	1,871,308	200,966	1,925,574	42,119	8,140
Distribution	6,246,928	8,527,961	3,889,114	0	11,251,561	3,684,513	6,917,605
Customer Accounts	1,903,337	1,549,715	1,734,175	0	1,206,803	644,997	484,424
Customer Service & Information	277,216	829,858	791,584	0	1,558,300	404,233	20,790
Administrative & General	5,039,263	10,458,678	4,893,792	0	12,980,506	2,085,181	1,383,350
Total Operating Expenses	$32,328,785	$47,351,688	$24,738,738	$1,493,868	$552,360,629	$11,136,946	$11,627,646
OTHER REVENUE DEDUCTIONS							
Depreciation & Amortization Expenses	$3,970,935	$5,104,982	$3,136,794	$0	$9,095,084	$1,465,703	$1,475,950
Taxes	1,071,417	1,585,792	1,975,221	0	2,848,561	425,908	644,415
Other Expenses	2,757,263	2,107,043	204,707	0	3,255,385	648,010	965,850
Non-operating (Gain) or Loss	(205,056)	(764,315)	(656,699)	0	(3,725,273)	(187,470)	(723,767)
Total Other Revenue Deductions	$7,594,559	$8,033,502	$4,660,023	$0	$11,473,757	$2,352,151	$2,362,447
Net Operating Income or (Loss)	$4,554,485	$3,587,889	$4,373,912	$3,391,531	$21,417,819	$366,680	$1,153,599
Fixed Capital	$167,436,435	$189,655,605	$97,412,678	$40,240,978	$340,713,070	$51,171,927	$60,009,165
Depreciation Reserve	73,086,034	74,848,079	(40,047,188)	14,434,522	89,327,222	18,626,097	24,698,294

Electric Cooperatives in Oregon

Source and Disposition of Electric Energy (kWh)

Year Ending December 31, 2024

	Blachly-Lane	Central Electric	Clearwater Power	Columbia Basin Electric	Columbia Power	Columbia Rural Electric
GENERATED OUTPUT FROM OWN PLANTS						
Hydroelectric	0	0	0	0	0	0
Steam, Internal Combustion, & Other	0	174,174	0	0	0	0
Total	0	174,174	0	0	0	0
PURCHASED ENERGY						
From Privately Owned Electric Utilities	0	0	0	0	0	0
From Publicly Owned Electric Utilities	0	0	0	0	0	0
From Other Sources (Non-Utility)	192,485,858	863,613,802	1,929,928	139,007,429	28,243,456	8,713,102
Total Purchases	192,485,858	863,613,802	1,929,928	139,007,429	28,243,456	8,713,102
Grand Total Available	192,485,858	863,787,976	1,929,928	139,007,429	28,243,456	8,713,102
SALES TO ULTIMATE CUSTOMERS						
Residential	51,428,201	570,581,386	1,363,690	42,739,403	15,211,549	873,521
Commercial & Industrial	134,374,296	195,187,924	420,075	47,323,179	4,543,166	695,384
Public Street and Highway Lighting	31,371	293,524	0	285,639	82,800	0
Other Public Authorities	0	0	0	0	0	0
Interdepartmental Sales	0	0	0	0	0	0
Irrigation Sales	465,616	50,782,945	9,816	37,160,619	5,666,005	4,519,996
Other Sales to Ultimate Customers	0	0	0	0	0	0
Total Sales to Ultimate Customers	186,299,484	816,845,779	1,793,581	127,508,840	25,503,520	6,088,901
Sales for Resale	0	0	0	0	0	2,074,100
Total All Sales	186,299,484	816,845,779	1,793,581	127,508,840	25,503,520	8,163,001
Percentage of Oregon Sales	100%	100%	1.04%	100%	100%	2.1386%
ENERGY NOT REPORTED AS SOLD						
Used by Utility	288,290	807,436	0	184,332	92,827	0
Supplied Without Charge	0	46,134,761	0	0	0	0
Loss	5,898,084	0	136,347	11,314,257	2,647,109	550,101
Total Unsold	6,186,374	46,942,197	136,347	11,498,589	2,739,936	550,101
Grand Total Disposition	192,485,858	863,787,976	1,929,928	139,007,429	28,243,456	8,713,102

Electric Cooperatives in Oregon

Source and Disposition of Electric Energy (kWh)

Year Ending December 31, 2024

	Consumers Power	Coos-Curry Electric	Douglas Electric	Harney Electric	Hood River Electric	Lane Electric
GENERATED OUTPUT FROM OWN PLANTS						
Hydroelectric	0	0	0	0	0	0
Steam, Internal Combustion, & Other	0	0	0	0	0	992,910
Total	0	0	0	0	0	992,910
PURCHASED ENERGY						
From Privately Owned Electric Utilities	0	0	0	0	0	0
From Publicly Owned Electric Utilities	0	0	0	0	0	0
From Other Sources (Non-Utility)	440,491,072	344,172,013	165,617,655	110,486,779	138,309,993	247,005,179
Total Purchases	440,491,072	344,172,013	165,617,655	110,486,779	138,309,993	247,005,179
Grand Total Available	440,491,072	344,172,013	165,617,655	110,486,779	138,309,993	247,998,089
SALES TO ULTIMATE CUSTOMERS						
Residential	264,442,885	180,143,077	128,747,807	19,888,207	57,030,122	185,173,191
Commercial & Industrial	140,317,939	141,183,191	23,315,907	12,086,592	71,243,612	48,451,322
Public Street and Highway Lighting	406,102	365,448	69,513	0	0	372,145
Other Public Authorities	0	0	0	0	0	0
Interdepartmental Sales	0	0	0	0	0	0
Irrigation Sales	5,622,357	5,208,095	1,621,263	69,349,872	1,849,865	46,160
Other Sales to Ultimate Customers	0	0	0	0	0	0
Total Sales to Ultimate Customers	410,789,283	326,899,811	153,754,490	101,324,671	130,123,599	234,042,818
Sales for Resale	0	0	0	0	0	0
Total All Sales	410,789,283	326,899,811	153,754,490	101,324,671	130,123,599	234,042,818
Percentage of Oregon Sales	100%	100%	100%	46.6478%	100%	100%
ENERGY NOT REPORTED AS SOLD						
Used by Utility	1,580,427	584,841	70,682	160,660	0	0
Supplied Without Charge	0	0	0	0	0	0
Loss	28,121,362	16,687,361	11,792,483	9,001,448	8,186,394	13,955,271
Total Unsold	29,701,789	17,272,202	11,863,165	9,162,108	8,186,394	13,955,271
Grand Total Disposition	440,491,072	344,172,013	165,617,655	110,486,779	138,309,993	247,998,089

Electric Cooperatives in Oregon

Source and Disposition of Electric Energy (kWh)

Year Ending December 31, 2024

	Midstate Electric	Oregon Trail Electric	Salem Electric	Surprise Valley Electrification	Umatilla Electric	Wasco Electric	West Oregon Electric
GENERATED OUTPUT FROM OWN PLANTS							
Hydroelectric	0	0	0	0	0	0	0
Steam, Internal Combustion, & Other	0	368,500 [A]	0	0	1,479,131	0	0
Total	0	368,500	0	0	1,479,131	0	0
PURCHASED ENERGY							
From Privately Owned Electric Utilities	0	0	0	0	0	0	0
From Publicly Owned Electric Utilities	0	0	0	0	0	0	17,620,464
From Other Sources (Non-Utility)	482,056,816	707,068,350	331,932,647	43,471,575	8,599,385,537	118,001,582	57,592,097 [B]
Total Purchases	482,056,816	707,068,350	331,932,647	43,471,575	8,599,385,537	118,001,582	75,212,561
Grand Total Available	482,056,816	707,436,850	331,932,647	43,471,575	8,600,864,668	118,001,582	75,212,561
SALES TO ULTIMATE CUSTOMERS							
Residential	288,110,772	312,802,545	192,449,479	16,860,840	181,782,946	54,060,019	50,598,017
Commercial & Industrial	115,288,170	297,902,722	123,774,556	7,447,848	7,890,587,994	41,349,801	18,307,111
Public Street and Highway Lighting	6,480	1,640,131	1,577,146	20,290	416,049	77,040	330,841
Other Public Authorities	0	0	0	0	0	0	0
Interdepartmental Sales	0	0	0	0	0	0	146,993
Irrigation Sales	49,810,079	62,820,656	0	14,507,215	359,142,590	14,427,876	48,652
Other Sales to Ultimate Customers	0	0	0	0	0	0	0
Total Sales to Ultimate Customers	453,215,501	675,166,054	317,801,181	38,836,193	8,431,929,579	109,914,736	69,431,614
Sales for Resale	0	0	0	0	0	0	0
Total All Sales	453,215,501	675,166,054	317,801,181	38,836,193	8,431,929,579	109,914,736	69,431,614
Percentage of Oregon Sales	100%	100%	100%	27.296%	100%	100%	100%
ENERGY NOT REPORTED AS SOLD							
Used by Utility	1,248,927	1,173,498	0	494,970	3,521,485	39,750	0
Supplied Without Charge	0	0	0	0	0	0	0
Loss	27,592,388	31,097,298	14,131,466	4,140,412	165,413,604	8,047,096	5,780,947
Total Unsold	28,841,315	32,270,796	14,131,466	4,635,382	168,935,089	8,086,846	5,780,947
Grand Total Disposition	482,056,816	707,436,850	331,932,647	43,471,575	8,600,864,668	118,001,582	75,212,561

[A] Community solar project that went live during October 2024.

[B] Energy is purchased from PNGC, which combines purchases from BPA, PPL, and PGE.

Electric Cooperatives in Oregon

Sales Statistics

Year Ending December 31, 2024

	Blachly-Lane	Central Electric	Clearwater Power	Columbia Basin Electric	Columbia Power	Columbia Rural Electric
AVERAGE NUMBER OF CUSTOMERS						
Residential	3,279	34,562	144	3,184	1,486	44
Commercial & Industrial	322	3,076	32	574	253	27
Public Street and Highway Lighting	11	142	0	11	4	0
Other Public Authorities	0	0	0	0	0	0
Interdepartmental	0	0	0	0	0	0
Irrigation	69	1,084	1	243	274	57
Other Sales to Ultimate Customers	0	0	0	0	0	0
Total Customers	3,681 [A]	38,864 [B]	177	4,012 [C]	2,017 [D]	128 [E]
Sales for Resale	0	0	0	0	0	1
Total	3,681 [A]	38,864 [B]	177	4,012 [C]	2,017 [D]	129 [E]
AVERAGE REVENUE PER KWH SOLD (Cents)						
Residential	14.92	9.75	13.67	11.24	14.08	12.94
Commercial & Industrial	6.63	7.27	12.75	9.52	12.40	17.97
Public Street and Highway Lighting	31.27	25.13	0.00	21.25	20.33	0.00
Other Public Authorities	0.00	0.00	0.00	0.00	0.00	0.00
Interdepartmental Sales	0.00	0.00	0.00	0.00	0.00	0.00
Irrigation Sales	21.18	8.60	23.75	6.18	8.10	8.32
Other Sales to Ultimate Customers	0.00	0.00	0.00	0.00	0.00	0.00
Total Sales to Ultimate Customers	8.96	9.09	13.51	9.15	12.47	10.09
Sales for Resale	0.00	0.00	0.00	0.00	0.00	17.32
Total	8.96	9.09	13.51	9.15	12.47	11.92
RESIDENTIAL AVERAGE PER CUSTOMER						
Revenue	$2,340	$1,610	$1,294	$1,508	$1,441	$2,570
Sales (kWh)	15,684	16,509	9,470	13,423	10,237	19,853
PLANT OUTPUT CAPACITY (kW)						
Hydroelectric	0	0	0	0	0	0
Steam, Internal Combustion, & Other	0	0	0	0	0	0

[A] Includes the following duplicates: 580 Residential; 161 Commercial/Industrial; 8 Public Street and Highway Lighting; and 43 Irrigation Sales.
[B] Includes the following duplicates: 3,316 Residential; 466 Commercial/Industrial; 5 Public Street and Highway Lighting; and 159 Irrigation Sales.
[C] Includes the following duplicates: 889 Residential; 181 Commercial/Industrial; and 174 Irrigation Sales.
[D] Includes the following duplicates: 525 Residential; 135 Commercial/Industrial; and 115 Irrigation Sales.
[E] Includes the following duplicates: 4 Residential; 11 Commercial/Industrial; and 45 Irrigation Sales.

Electric Cooperatives in Oregon

Sales Statistics

Year Ending December 31, 2024

	Consumers Power	Coos-Curry Electric	Douglas Electric	Harney Electric	Hood River Electric	Lane Electric
AVERAGE NUMBER OF CUSTOMERS						
Residential	18,751	15,861	9,819	954	3,479	12,411
Commercial & Industrial	4,483	2,235	719	915	397	1,168
Public Street and Highway Lighting	18	3	8	0	0	50
Other Public Authorities	0	0	0	0	0	0
Interdepartmental	0	0	0	0	0	0
Irrigation	517	426	86	609	139	19
Other Sales to Ultimate Customers	0	0	0	0	0	0
Total Customers	23,769 [A]	18,525	10,632 [B]	2,478 [C]	4,015 [D]	13,648 [E]
Sales for Resale	0	0	0	0	0	0
Total	23,769 [A]	18,525	10,632 [B]	2,478 [C]	4,015 [D]	13,648 [E]
AVERAGE REVENUE PER KWH SOLD (Cents)						
Residential	13.01	13.31	12.68	8.69	8.71	12.55
Commercial & Industrial	11.32	10.68	12.25	9.70	6.68	10.32
Public Street and Highway Lighting	36.95	45.72	14.94	0.00	0.00	23.27
Other Public Authorities	0.00	0.00	0.00	0.00	0.00	0.00
Interdepartmental Sales	0.00	0.00	0.00	0.00	0.00	0.00
Irrigation Sales	14.66	15.48	11.70	6.19	11.00	25.72
Other Sales to Ultimate Customers	0.00	0.00	0.00	0.00	0.00	0.00
Total Sales to Ultimate Customers	12.48	12.25	12.60	7.10	7.63	12.11
Sales for Resale	0.00	0.00	0.00	0.00	0.00	0.00
Total	12.48	12.25	12.60	7.10	7.63	12.11
RESIDENTIAL AVERAGE PER CUSTOMER						
Revenue	$1,835	$1,512	$1,662	$1,812	$1,428	$1,872
Sales (kWh)	14,103	11,358	13,112	20,847	16,393	14,920
PLANT OUTPUT CAPACITY (kW)						
Hydroelectric	0	0	0	0	0	0
Steam, Internal Combustion, & Other	0	0	0	0	0	0

[A] Includes the following duplicates: 1,694 Residential; 2,587 Commercial/Industrial; and 397 Irrigation Sales.

[B] Includes the following duplicates: 2,296 Residential; 423 Commercial/Industrial; 4 Public Street and Highway Lighting; and 6 Irrigation Sales.

[C] Includes the following duplicates: 289 Residential; 602 Commercial/Industrial; and 442 Irrigation Sales.

[D] Includes the following duplicates: 882 Residential; 210 Commercial/Industrial; and 39 Irrigation Sales.

[E] Includes the following duplicates: 16 Public Street and Highway Lighting.

Electric Cooperatives in Oregon

Sales Statistics

Year Ending December 31, 2024

	Midstate Electric	Oregon Trail Electric	Salem Electric	Surprise Valley Electrification	Umatilla Electric	Wasco Electric	West Oregon Electric
AVERAGE NUMBER OF CUSTOMERS							
Residential	18,593	25,997	18,385	1,212	12,620	3,847	4,345
Commercial & Industrial	2,421	4,458	2,383	483	2,486	583	302
Public Street and Highway Lighting	1	43	77	1	7	4	7
Other Public Authorities	0	0	0	0	0	0	0
Interdepartmental	0	0	0	0	0	0	6
Irrigation	502	1,315	0	275	1,533	315	11
Other Sales to Ultimate Customers	0	0	0	0	0	0	0
Total Customers	21,517	31,813	20,845	1,971	16,646	4,749 [A]	4,671 [B]
Sales for Resale	0	0	0	0	0	0	0
Total	21,517	31,813	20,845	1,971	16,646	4,749 [A]	4,671 [B]
AVERAGE REVENUE PER KWH SOLD (Cents)							
Residential	10.52	10.08	11.02	12.77	9.84	14.08	23.34
Commercial & Industrial	9.27	7.41	9.72	13.19	6.85	9.91	17.50
Public Street and Highway Lighting	22.22	20.94	17.79	20.00	20.50	30.08	14.25
Other Public Authorities	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Interdepartmental Sales	0.00	0.00	0.00	0.00	0.00	0.00	3.13
Irrigation Sales	7.62	6.55	0.00	11.96	6.08	11.32	21.85
Other Sales to Ultimate Customers	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Sales to Ultimate Customers	9.89	8.60	10.55	12.55	6.89	12.16	21.71
Sales for Resale	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	9.89	8.60	10.55	12.55	6.89	12.16	21.71
RESIDENTIAL AVERAGE PER CUSTOMER							
Revenue	$1,631	$1,212	$1,154	$1,776	$1,418	$1,979	$2,718
Sales (kWh)	15,496	12,032	10,468	13,912	14,404	14,053	11,645
PLANT OUTPUT CAPACITY (kW)							
Hydroelectric	0	0	0	0	0	0	0
Steam, Internal Combustion, & Other	0	200 [C]	0	0	1,057 [D]	0	0

[A] Includes the following duplicates: 1,035 Residential; 450 Commercial/Industrial; and 166 Irrigation Sales.

[B] Includes the following duplicates: 183 Residential; 128 Commercial/Industrial; 3 Public Street and Highway Lighting; and 3 Interdepartmental Sales.

[C] Community solar project that went live during October 2024.

[D] Name plate capacity of their two solar sites.

Municipal-Owned Electric Utilities in Oregon

Operating Revenues, Expenses, and Income

Year Ending December 31, 2024

	City of Ashland	City of Bandon	Canby Utility	City of Cascade Locks	City of Drain Light & Power	Eugene Water & Electric Board
OPERATING REVENUES						
Residential	$9,163,015	$3,912,219	$7,600,031	$1,000,749	$781,386	$116,766,028
Commercial & Industrial	5,176,410	2,262,252	7,094,957	2,017,808	823,628	104,057,946
Public Street and Highway Lighting	0	0	45,165	45,444	2,759	1,018,213
Other Public Authorities	2,386,396	341,662	214,090	233,865	0	34,064
Interdepartmental Sales	0	188,166	186,160	0	0	1,398,437
Irrigation Sales	0	249,236	0	0	0	0
Other Sales to Ultimate Customers	0	41,108	0	0	10,197	0
Total Revenue from Ultimate Customers	$16,725,821	$6,994,643	$15,140,402	$3,297,866	$1,617,970	$223,274,687
Sales for Resale	0	0	0	0	0	54,278,915
Total Revenue – Sales of Electric Energy	$16,725,821	$6,994,643	$15,140,402	$3,297,866	$1,617,970	$277,553,602
Miscellaneous Revenues	453,698	518,974	1,153,191	0	13,385	25,435,504
Total Operating Revenues	$17,179,519	$7,513,617	$16,293,593	$3,297,866	$1,631,355	$302,989,106
OPERATING EXPENSES						
Production	$0	$0	$0	$0	$0	$17,524,855
Purchase	8,140,494	1,929,001	6,905,941	2,008,624	704,115	135,820,399
Transmission	1,066,039	587,319	905,440	218,395	0	25,435,868
Distribution	14,158,662	2,544,617	1,076,936	832,563	331,293	33,525,041
Customer Accounts	0	564,220	0	0	114,952	10,509,633
Customer Service & Information	401,439	95,155	655,822	0	0	6,379,601
Administrative & General	415,271	567,630	1,607,337	378,017	122,808	29,822,880
Total Operating Expenses	$24,181,905	$6,287,942	$11,151,476	$3,437,600	$1,273,168	$259,018,277
OTHER REVENUE DEDUCTIONS						
Depreciation & Amortization Expenses	$337,184	$0	$1,298,172	$0	$30,048	$28,835,198
Taxes	0	419,265	759,392	0	135,078	312,984
Other Expenses	0	30,049	241,422	0	0	11,270,718
Non-operating (Gain) or Loss	0	0	30,345	0	0	274,229
Total Other Revenue Deductions	$337,184	$449,314	$2,329,331	$0	$165,126	$40,693,129
Net Operating Income or (Loss)	($7,339,570)	$776,361	$2,812,787	($139,734)	$193,061	$3,277,700
Fixed Capital	$0	$19,333,123	$51,104,816	$4,732,760	$0	$1,014,929,051
Depreciation Reserve	0	13,182,823	18,975,893	2,811,314	0	0

Municipal-Owned Electric Utilities in Oregon

Operating Revenues, Expenses, and Income

Year Ending December 31, 2024

	City of Forest Grove Light & Power	Hermiston Energy Services	City of McMinnville Water & Light	Milton-Freewater City Light & Power	City of Monmouth	Springfield Utility Board
OPERATING REVENUES						
Residential	$11,941,662	$5,155,753	$15,461,262	$5,184,908	$4,871,775	$29,315,720
Commercial & Industrial	11,534,555	4,501,549	26,149,341	2,715,782	2,427,729	24,752,917
Public Street and Highway Lighting	(23,582)	138,217	286,922	39,644	57,352	109,863
Other Public Authorities	0	0	39,327	125,914	0	2,205,209
Interdepartmental Sales	0	0	0	0	0	441,268
Irrigation Sales	6,249	2,110	149,467	635,032	0	0
Other Sales to Ultimate Customers	133,659	0	122,606	99,664	0	0
Total Revenue from Ultimate Customers	$23,592,543	$9,797,629	$42,208,925	$8,800,944	$7,356,856	$56,824,977
Sales for Resale	0	0	0	0	0	0
Total Revenue – Sales of Electric Energy	$23,592,543	$9,797,629	$42,208,925	$8,800,944	$7,356,856	$56,824,977
Miscellaneous Revenues	8,723,466	335,210	4,677,118	715,856	526,711	2,796,474
Total Operating Revenues	$32,316,009	$10,132,839	$46,886,043	$9,516,800	$7,883,567	$59,621,451
OPERATING EXPENSES						
Production	$0	$0	$0	$0	$0	$0
Purchase	10,937,055	4,285,631	23,736,688	3,237,101	2,704,228	25,647,876
Transmission	1,482,507	614,391	3,353,501	702,284	455,819	4,010,022
Distribution	2,690,785	1,199,149	5,087,606	1,103,066	2,260,792	6,301,614
Customer Accounts	570,297	620,602	662,057	641,146	559,723	3,281,868
Customer Service & Information	0	0	0	454,601	0	2,251,251
Administrative & General	11,714,640	704,659	2,167,128	1,675,561	161,854	3,446,800
Total Operating Expenses	$27,395,284	$7,424,432	$35,006,980	$7,813,759	$6,142,416	$44,939,431
OTHER REVENUE DEDUCTIONS						
Depreciation & Amortization Expenses	$1,077,130	$815,535	$2,777,815	$218,434	$531,208	$3,741,812
Taxes	1,375,996	710,000	2,497,717	720,557	514,999	3,022,173
Other Expenses	63,084	1,082,212	904,998	520,546	1,417,804	(2,500,333)
Non-operating (Gain) or Loss	(273,734)	67,172	461,613	0	0	(3,140,722)
Total Other Revenue Deductions	$2,242,476	$2,674,918	$6,642,143	$1,459,537	$2,464,011	$1,122,930
Net Operating Income or (Loss)	$2,678,249	$33,489	$5,236,920	$243,504	($722,860)	$13,559,090
Fixed Capital	$47,257,486	$26,932,146	$90,960,355	$15,388,355	$19,413,487	$165,875,310
Depreciation Reserve	(17,677,382)	11,276,850	37,941,110	0	8,200,326	(71,495,293)

Municipal-Owned Electric Utilities in Oregon

Source and Disposition of Electric Energy (kWh)

Year Ending December 31, 2024

	City of Ashland	City of Bandon	Canby Utility	City of Cascade Locks	City of Drain Light & Power	Eugene Water & Electric Board
GENERATED OUTPUT FROM OWN PLANTS						
Hydroelectric	0	0	0	0	0	285,387,000
Steam, Internal Combustion, & Other	0	0	0	0	0	169,097,000
Total	0	0	0	0	0	454,484,000
PURCHASED ENERGY						
From Privately Owned Electric Utilities	0	0	0	0	0	57,808,000
From Publicly Owned Electric Utilities	0	0	0	0	0	70,008,000
From Other Sources (Non-Utility)	162,894,193	67,727,070	200,644,754	42,864,106	16,583,160	2,669,623,000
Total Purchases	162,894,193	67,727,070	200,644,754	42,864,106	16,583,160	2,797,439,000
Grand Total Available	162,894,193	67,727,070	200,644,754	42,864,106	16,583,160	3,251,923,000
SALES TO ULTIMATE CUSTOMERS						
Residential	88,761,125	39,213,742	83,893,155	10,665,152	7,687,587	945,843,056
Commercial & Industrial	45,902,681	21,540,776	104,973,850	28,659,321	8,431,135	1,304,964,584
Public Street and Highway Lighting	0	0	482,491	0	28,108	9,289,971
Other Public Authorities	28,230,387	3,274,247	3,174,371	2,071,357	0	456,841
Interdepartmental Sales	0	2,237,666	2,514,797	0	0	15,304,579
Irrigation Sales	0	1,433,291	0	0	0	0
Other Sales to Ultimate Customers	0	27,348	0	0	46,083	0
Total Sales to Ultimate Customers	162,894,193	67,727,070	195,038,665	41,395,830	16,192,913	2,275,859,032
Sales for Resale	0	0	0	0	0	896,442,100
Total All Sales	162,894,193	67,727,070	195,038,665	41,395,830	16,192,913	3,172,301,132
Percentage of Oregon Sales	100%	100%	100%	100%	100%	100%
ENERGY NOT REPORTED AS SOLD						
Used by Utility	0	2,237,666	0	0	0	0
Supplied Without Charge	0	0	0	0	0	11,907,368
Loss	0	(2,237,666)	5,606,089	1,468,276	390,247	67,714,500
Total Unsold	0	0	5,606,089	1,468,276	390,247	79,621,868
Grand Total Disposition	162,894,193	67,727,070	200,644,754	42,864,106	16,583,160	3,251,923,000

Municipal-Owned Electric Utilities in Oregon

Source and Disposition of Electric Energy (kWh)

Year Ending December 31, 2024

	City of Forest Grove Light & Power	Hermiston Energy Services	City of McMinnville Water & Light	Milton-Freewater City Light & Power	City of Monmouth	Springfield Utility Board
GENERATED OUTPUT FROM OWN PLANTS						
Hydroelectric	0	0	0	0	0	0
Steam, Internal Combustion, & Other	0	0	0	0	0	0
Total	0	0	0	0	0	0
PURCHASED ENERGY						
From Privately Owned Electric Utilities	0	0	0	0	0	0
From Publicly Owned Electric Utilities	0	0	0	0	0	0
From Other Sources (Non-Utility)	279,407,708	110,405,868	739,298,770	104,039,798	78,519,517	748,523,033
Total Purchases	279,407,708	110,405,868	739,298,770	104,039,798	78,519,517	748,523,033
Grand Total Available	279,407,708	110,405,868	739,298,770	104,039,798	78,519,517	748,523,033
SALES TO ULTIMATE CUSTOMERS						
Residential	121,361,832	53,574,885	204,574,979	56,656,887	48,411,615	361,741,217
Commercial & Industrial	141,560,954	52,711,150	516,799,859	28,803,802	27,176,262	327,724,890
Public Street and Highway Lighting	712,605	704,424	1,638,798	388,132	186,478	1,604,361
Other Public Authorities	0	0	466,320	1,767,280	0	27,160,278
Interdepartmental Sales	0	0	0	0	0	5,277,318
Irrigation Sales	66,304	56,105	1,809,793	505,856	0	0
Other Sales to Ultimate Customers	216,832	0	909,746	0	0	0
Total Sales to Ultimate Customers	263,918,527	107,046,564	726,199,495	88,121,957	75,774,355	723,508,064
Sales for Resale	0	0	0	0	0	0
Total All Sales	263,918,527	107,046,564	726,199,495	88,121,957	75,774,355	723,508,064
Percentage of Oregon Sales	100%	100%	100%	100%	100%	100%
ENERGY NOT REPORTED AS SOLD						
Used by Utility	0	0	0	0	0	5,277,318
Supplied Without Charge	0	0	0	0	0	0
Loss	15,489,181	3,359,304	13,099,275	15,917,841	2,745,162	19,737,651
Total Unsold	15,489,181	3,359,304	13,099,275	15,917,841	2,745,162	25,014,969
Grand Total Disposition	279,407,708	110,405,868	739,298,770	104,039,798	78,519,517	748,523,033

Municipal-Owned Electric Utilities in Oregon

Sales Statistics

Year Ending December 31, 2024

	City of Ashland	City of Bandon	Canby Utility	City of Cascade Locks	City of Drain Light & Power	Eugene Water & Electric Board
AVERAGE NUMBER OF CUSTOMERS						
Residential	10,672	3,691	7,750	841	560	90,124
Commercial & Industrial	1,330	715	793	124	91	10,343
Public Street and Highway Lighting	0	0	1	736	62	18
Other Public Authorities	202	66	47	88	0	1
Interdepartmental	0	33	12	0	0	1
Irrigation	0	128	0	0	0	0
Other Sales to Ultimate Customers	0	210	0	0	59	0
Total Customers	12,204	4,843 [A]	8,603 [B]	1,789 [C]	772	100,487
Sales for Resale	0	0	0	0	0	0
Total	12,204	4,843 [A]	8,603 [B]	1,789 [C]	772	100,487
AVERAGE REVENUE PER KWH SOLD (Cents)						
Residential	10.32	9.98	9.06	9.38	10.16	12.35
Commercial & Industrial	11.28	10.50	6.76	7.04	9.77	7.97
Public Street and Highway Lighting	0.00	0.00	9.36	N/A	9.82	10.96
Other Public Authorities	8.45	10.43	6.74	11.29	0.00	7.46
Interdepartmental Sales	0.00	8.41	7.40	0.00	0.00	9.14
Irrigation Sales	0.00	17.39	0.00	0.00	0.00	0.00
Other Sales to Ultimate Customers	0.00	150.31	0.00	0.00	22.13	0.00
Total Sales to Ultimate Customers	10.27	10.33	7.76	7.97	9.99	9.81
Sales for Resale	0.00	0.00	0.00	0.00	0.00	6.05
Total	10.27	10.33	7.76	7.97	9.99	8.75
RESIDENTIAL AVERAGE PER CUSTOMER						
Revenue	$859	$1,060	$981	$1,190	$1,395	$1,296
Sales (kWh)	8,317	10,624	10,825	12,682	13,728	10,495
PLANT OUTPUT CAPACITY (kW)						
Hydroelectric	0	0	0	0	0	0
Steam, Internal Combustion, & Other	0	0	0	0	0	0

[A] Includes the following duplicates: 463 Residential; 66 Commercial/Industrial; 7 Other Public Authorities; 1 Interdepartmental Sales; 10 Irrigation; and 84 All Other Sales to Ultimate Consumers.
[B] Includes the following duplicates: 355 Residential; 289 Commercial/Industrial; 1 Public Street and Highway Lighting; 47 Other Public Authorities; and 12 Interdepartmental Sales.
[C] Includes the following duplicates: 65 Residential; 48 Commercial/Industrial; and 72 Other Public Authorities.

Municipal-Owned Electric Utilities in Oregon

Sales Statistics

Year Ending December 31, 2024

	City of Forest Grove Light & Power	Hermiston Energy Services	City of McMinnville Water & Light	Milton-Freewater City Light & Power	City of Monmouth	Springfield Utility Board
AVERAGE NUMBER OF CUSTOMERS						
Residential	10,369	4,761	17,190	3,595	4,571	29,787
Commercial & Industrial	935	841	2,674	549	364	3,114
Public Street and Highway Lighting	1	1	1	3	1	3
Other Public Authorities	0	0	2	7	0	333
Interdepartmental	0	0	0	0	0	50
Irrigation	11	1	56	263	0	0
Other Sales to Ultimate Customers	0	0	309	640	0	0
Total Customers	11,316	5,604	20,232 [A]	5,057	4,936	33,287
Sales for Resale	0	0	0	0	0	0
Total	11,316	5,604	20,232 [A]	5,057	4,936	33,287
AVERAGE REVENUE PER KWH SOLD (Cents)						
Residential	9.84	9.62	7.56	9.15	10.06	8.10
Commercial & Industrial	8.15	8.54	5.06	9.43	8.93	7.55
Public Street and Highway Lighting	(3.31)	19.62	17.51	10.21	30.76	6.85
Other Public Authorities	0.00	0.00	8.43	7.12	0.00	N/A
Interdepartmental Sales	0.00	0.00	0.00	0.00	0.00	8.36
Irrigation Sales	9.42	3.76	8.26	125.54	0.00	0.00
Other Sales to Ultimate Customers	61.64	0.00	13.48	0.00	0.00	0.00
Total Sales to Ultimate Customers	8.94	9.15	5.81	9.99	9.71	7.85
Sales for Resale	0.00	0.00	0.00	0.00	0.00	0.00
Total	8.94	9.15	5.81	9.99	9.71	7.85
RESIDENTIAL AVERAGE PER CUSTOMER						
Revenue	$1,152	$1,083	$899	$1,442	$1,066	$984
Sales (kWh)	11,704	11,253	11,901	15,760	10,591	12,144
PLANT OUTPUT CAPACITY (kW)						
Hydroelectric	0	0	0	0	0	0
Steam, Internal Combustion, & Other	0	0	0	0	0	0

[A] Includes the following duplicates: 81 Residential and 262 Commercial/Industrial.

People's Utility Districts in Oregon

Operating Revenues, Expenses, and Income

Year Ending December 31, 2024

	Central Lincoln	Clatskanie	Columbia River	Emerald	Northern Wasco County	Tillamook
OPERATING REVENUES						
Residential	$46,668,287	$5,549,808	$21,464,386	$32,181,550	$11,222,999	$29,566,414
Commercial & Industrial	45,888,771	44,045,041	16,294,689	16,780,198	102,568,385	16,799,257
Public Street and Highway Lighting	1,032,675	28,186	151,148	122,755	348,252	468,971
Other Public Authorities	0	0	0	0	0	0
Interdepartmental Sales	0	0	0	0	0	0
Irrigation Sales	0	0	208,866	791,392	230,908	0
Other Sales to Ultimate Customers	0	0	0	999,329	0	0
Total Revenue from Ultimate Customers	$93,589,733	$49,623,035	$38,119,089	$50,875,224	$114,370,543	$46,834,642
Sales for Resale	0	10,316,895	0	5,073,081	0	0
Total Revenue – Sales of Electric Energy	$93,589,733	$59,939,930	$38,119,089	$55,948,305	$114,370,543	$46,834,642
Miscellaneous Revenues	6,269,080	2,414,790	416,479	156,226	255,120	630,181
Total Operating Revenues	$99,858,813	$62,354,720	$38,535,568	$56,104,531	$114,625,663	$47,464,823
OPERATING EXPENSES						
Production	$0	$0	$0	$1,234,299	$1,285,669	$0
Purchase	44,695,853	46,704,681	19,662,455	29,751,607	87,226,617	16,749,365
Transmission	0	4,960,871	0	0	276,879	2,497,588
Distribution	16,381,532	3,366,308	2,954,893	7,085,440	4,420,259	12,292,907
Customer Accounts	2,426,592	1,132,393	1,064,950	1,537,451	965,781	1,529,151
Customer Service & Information	249,112	365,153	255,988	1,008,872	852,486	1,453,137
Administrative & General	11,630,655	4,360,589	6,382,624	5,616,161	6,431,864	5,936,727
Total Operating Expenses	$75,383,744	$60,889,995	$30,320,910	$46,233,830	$101,459,553	$40,458,875
OTHER REVENUE DEDUCTIONS						
Depreciation & Amortization Expenses	$9,520,773	$2,944,191	$2,502,718	$6,019,436	$3,415,869	$3,532,646
Taxes	3,578,247	568,148	1,577,207	1,821,292	4,164,505	1,127,461
Other Expenses	982,571	224,278	0	770,249	1,340,466	1,376,512
Non-operating (Gain) or Loss	0	0	(814,215)	(1,860,625)	(17,621,405)	(1,465,728)
Total Other Revenue Deductions	$14,081,591	$3,736,617	$3,265,710	$6,750,352	($8,700,565)	$4,570,891
Net Operating Income or (Loss)	$10,393,478	($2,271,891)	$4,948,948	$3,120,349	$21,866,675	$2,435,057
Fixed Capital	$341,296,204	$91,925,015	$92,725,265	$0	$146,303,768	$133,471,153
Depreciation Reserve	180,211,898	(51,802,277)	40,750,330	0	(57,456,092)	(46,961,962)

People's Utility Districts in Oregon

Source and Disposition of Electric Energy (kWh)

Year Ending December 31, 2024

	Central Lincoln	Clatskanie	Columbia River	Emerald	Northern Wasco County	Tillamook
GENERATED OUTPUT FROM OWN PLANTS						
Hydroelectric	0	91,774,000	0	0	78,798,366	0
Steam, Internal Combustion, & Other	0	0	0	23,041,060	0	0
Total	0	91,774,000	0	23,041,060	78,798,366	0
PURCHASED ENERGY						
From Privately Owned Electric Utilities	0	12,959,000	0	22,190,000	105,408,000	0
From Publicly Owned Electric Utilities	0	24,628,000	0	30,778,000	766,575,000	2,593,200
From Other Sources (Non-Utility)	1,198,253,050	774,488,000	503,418,242	442,077,000	593,232,674	506,369,196
Total Purchases	1,198,253,050	812,075,000	503,418,242	495,045,000	1,465,215,674	508,962,396
Grand Total Available	1,198,253,050	903,849,000	503,418,242	518,086,060	1,544,014,040	508,962,396
SALES TO ULTIMATE CUSTOMERS						
Residential	426,808,732	69,471,025	231,554,962	291,287,851	145,325,754	250,103,957
Commercial & Industrial	765,583,007	896,051,920	240,487,420	175,159,555	1,382,213,171	236,523,800
Public Street and Highway Lighting	2,310,279	94,476	819,246	540,443	712,034	2,945,251
Other Public Authorities	0	0	0	0	0	0
Interdepartmental Sales	0	0	0	0	0	0
Irrigation Sales	0	0	2,269,187	6,634,055	2,350,675	0
Other Sales to Ultimate Customers	0	0	0	0	0	0
Total Sales to Ultimate Customers	1,194,702,018	965,617,421	475,130,815	473,621,904	1,530,601,634	489,573,008
Sales for Resale	0	0	0	22,252,000	0	0
Total All Sales	1,194,702,018	965,617,421	475,130,815	495,873,904	1,530,601,634	489,573,008
Percentage of Oregon Sales	100%	92.71%	100%	100%	100.00%	100%
ENERGY NOT REPORTED AS SOLD						
Used by Utility	0	461,013	504,495	0	591,494	1,062,907
Supplied Without Charge	0	0	0	0	0	0
Loss	3,551,032	(62,229,434)	27,782,932	22,212,156	12,820,912	18,326,481
Total Unsold	3,551,032	(61,768,421)	28,287,427	22,212,156	13,412,406	19,389,388
Grand Total Disposition	1,198,253,050	903,849,000	503,418,242	518,086,060	1,544,014,040	508,962,396

People's Utility Districts in Oregon

Sales Statistics

Year Ending December 31, 2024

	Central Lincoln	Clatskanie	Columbia River	Emerald	Northern Wasco County	Tillamook
AVERAGE NUMBER OF CUSTOMERS						
Residential	35,904	3,761	18,207	19,968	9,844	20,133
Commercial & Industrial	5,623	545	2,038	2,255	670	2,327
Public Street and Highway Lighting	N/A	2	525	105	110	N/A
Other Public Authorities	0	0	0	0	0	0
Interdepartmental	0	0	0	0	0	0
Irrigation	0	0	47	516	51	0
Other Sales to Ultimate Customers	0	0	0	0	0	0
Total Customers	41,527	4,308	20,817 [A]	22,844	10,675 [B]	22,460
Sales for Resale	0	0	0	0	0	0
Total	41,527	4,308	20,817 [A]	22,844	10,675 [B]	22,460
AVERAGE REVENUE PER KWH SOLD (Cents)						
Residential	10.93	7.99	9.27	11.05	7.72	11.82
Commercial & Industrial	5.99	4.92	6.78	9.58	7.42	7.10
Public Street and Highway Lighting	N/A	29.83	18.45	22.71	48.91	N/A
Other Public Authorities	0.00	0.00	0.00	0.00	0.00	0.00
Interdepartmental Sales	0.00	0.00	0.00	0.00	0.00	0.00
Irrigation Sales	0.00	0.00	9.20	11.93	9.82	0.00
Other Sales to Ultimate Customers	0.00	0.00	0.00	0.00	0.00	N/A
Total Sales to Ultimate Customers	7.83	5.14	8.02	10.74	7.47	9.57
Sales for Resale	0.00	0.00	0.00	22.80	0.00	0.00
Total	7.83	6.21	8.02	11.28	7.47	9.57
RESIDENTIAL AVERAGE PER CUSTOMER						
Revenue	$1,300	$1,476	$1,179	$1,612	$1,140	$1,469
Sales (kWh)	11,887	18,471	12,718	14,588	14,763	12,423
PLANT OUTPUT CAPACITY (kW)						
Hydroelectric	0	18,000	0	0	0	0
Steam, Internal Combustion, & Other	0	0	0	0	0	0

[A] Includes the following duplicates: 1,829 Residential; 939 Commercial/Industrial; 524 Public Street and Highway Lighting; and 29 Irrigation Sales.

[B] Includes the following duplicates: 1,435 Residential; 329 Commercial/Industrial; 98 Public Street and Highway Lighting; and 35 Irrigation Sales.

Electric Utilities in Oregon

Selected Statistics

Year Ending December 31, 2024

	Cooperatives[A]	Municipalities	PUDs	Investor-Owned Utilities	Total
OPERATING REVENUES					
Residential	$297,707,769	$211,154,508	$146,653,444	$2,282,039,782	$2,937,555,503
Commercial & Industrial	667,036,750	193,514,874	242,376,341	2,270,957,581	3,373,885,545
Public Street and Highway Lighting	1,360,244	1,719,997	2,151,987	20,074,451	25,306,679
Other Public Authorities	0	5,580,525	0	0	5,580,525
Interdepartmental Sales	4,600	2,214,031	0	0	2,218,631
Irrigation Sales	47,040,416	1,042,094	1,231,166	[B]	49,313,676
Other Sales to Retail Energy Customers	0	407,234	999329	N/A	1,406,563
Revenue from Retail Energy Customers	$1,013,149,779	$415,633,264	$393,412,266	$4,573,071,814	$6,395,267,123
Sales for Resale	359,235	54,278,915	15,389,976	622,089,901	692,118,027
Total Revenue – Sales of Electric Energy	$1,013,509,014	$469,912,178	$408,802,242	$5,195,161,715	$7,087,385,150
(Less) Provision for Rate Refunds	0	0	0	37,264,125	37,264,125
Miscellaneous Revenues	9,903,610	45,349,587	10,141,877	205,418,808	270,813,882
Total Operating Revenues	$1,023,412,624	$515,261,766	$418,944,119	$5,363,316,398	$7,320,934,907
Revenue from ESS[C] Deliveries	0	0	0	41,948,439	41,948,439
OPERATING EXPENSES[A]					
Production	$8,763	$17,524,855	$2,519,968	$2,357,754,640	$2,377,808,226
Purchase	697,137,570	226,057,153	244,790,578	0	1,167,985,300
Transmission	6,735,436	38,831,585	7,735,338	231,395,445	284,697,804
Distribution	93,317,593	71,112,124	46,501,339	416,010,706	626,941,763
Customer Accounts	15,856,601	17,524,498	8,656,317	114,286,429	156,323,845
Customer Service & Information	8,255,496	10,237,870	4,184,748	35,992,832	58,670,946
Administrative & General	62,738,997	52,784,585	40,358,619	465,849,022	621,731,223
Total Operating Expenses	$884,050,456	$434,072,670	$354,746,907	$3,621,289,074	$5,294,159,107
OTHER REVENUE DEDUCTIONS					
Depreciation and Amortization Expenses	$53,331,431	$39,662,536	$27,935,632	$793,480,012	$914,409,612
Taxes	17,337,217	10,468,160	12,836,861	241,324,074	281,966,312
Other Expenses[D]	23,392,100	13,030,499	4,694,075	4,946,270	46,062,945
Non-operating (Gain) or Loss	(5,473,150)	(2,581,097)	(21,761,973)	2,426,176	(27,390,044)
Total Revenue Deductions	$88,587,599	$60,580,098	$23,704,596	$1,042,176,532	$1,215,048,825
Net Operating Income or (Loss)	$50,774,569	$20,608,997	$40,492,616	$699,850,792	$811,726,975

[A] Cooperatives: Operating Expenses exclude Surprise Valley Electrification.
[B] Irrigation Revenues included in Commercial & Industrial.
[C] ESS - Electricity Service Suppliers.
[D] Includes Interest Expenses.

Electric Utilities in Oregon

Selected Statistics

Year Ending December 31, 2024

	Cooperatives	Municipalities	PUDs	Investor-Owned Utilities	Total
AVERAGE NUMBER OF CUSTOMERS					
Residential	188,973	183,911	107,817	1,391,054	1,871,755
Commercial & Industrial	27,317	21,873	13,458	201,865	264,513
Public Street and Highway Lighting	387	827	742	707	2,662
Other Public Authorities	0	746	0	0	746
Interdepartmental	6	96	0	0	102
Irrigation	7,475	459	614	[A]	8,549
Other Sales to Retail Energy Customers	0	1,218	0	N/A	1,218
Total Customers	224,158	209,130	122,631	1,593,626	2,149,545 [B]
SALES (MWh)					
Residential	2,614,288	2,022,385	1,414,552	13,714,487	19,765,712
Commercial & Industrial	9,313,801	2,609,249	3,696,019	20,149,738	35,768,807
Public Street and Highway Lighting	5,975	15,035	7,422	73,449	101,881
Other Public Authorities	0	66,601	0	0	66,601
Interdepartmental Sales	147	25,334	0	0	25,481
Irrigation Sales	683,060	3,871	11,254	[A]	698,185
Other Sales to Retail Energy Customers	0	1,200	0	N/A	1,200
Total Sales	12,617,270	4,743,677	5,129,247	33,937,674	56,427,867
ESS[B] Deliveries	0	0	0	2,879,469	2,879,469
AVERAGE REVENUE PER KWH SOLD (Cents)					
Residential	11.39	10.44	10.37	16.64	14.86
Commercial & Industrial	7.16	7.42	6.56	11.27	9.43
Public Street and Highway Lighting	22.77	11.44	29.00	27.33	24.84
Other Public Authorities	0	8.38	0	0.00	8.38
Interdepartmental Sales	0	8.74	0	0	8.71
Irrigation Sales	6.89	26.92	10.94	[A]	7.06
Other Sales to Retail Energy Customers	0.00	33.94	N/A	N/A	117.21
Total Sales	8.03	8.76	7.67	13.47	11.33
RESIDENTIAL AVERAGE PER CUSTOMER					
Revenue	$1,575	$1,148	$1,360	$1,641	$1,569
Sales (kWh)	13,834	10,997	13,120	9,859	10,560

[A] Irrigation customers and sales included in Commercial & Industrial.

[B] ESS - Electricity Service Suppliers. ESS not included in Total Customers.

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Natural Gas

Foreword to Natural Gas Utilities

There are three investor-owned natural gas utilities operating in Oregon. They reported sales of approximately 913.5 million therms in Oregon during 2024 resulting in total operating revenues of approximately $1.21 billion.

Northwest Natural Gas Company, dba NW Natural, is the largest natural gas distribution utility operating in Oregon. During 2024, NW Natural's Oregon total operating revenues comprised approximately 79 percent of the total for the state. The company's operating expenses, excluding depreciation, amortization, and taxes, represented approximately 78 percent of the total expenses for the three utilities. NW Natural's delivered therm volumes, excluding transportation, accounted for approximately 79 percent of Oregon natural gas utility therm sales.

Index to Natural Gas Utilities

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Investor-Owned

Avista Utilities (Avista)

Cascade Natural Gas Corporation (Cascade)

Northwest Natural Gas Company (dba NW Natural)

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Natural Gas Purchase and Delivery Statistics – Total Oregon 54

Investor-Owned Natural Gas Utilities in Oregon

Ten-Year Summary
Selected Statistics

	Total			Residential			
	Revenue from Natural Gas Sales	Therms of Natural Gas Sold	Average Number of Customers	Average Number of Customers	Revenue Per Therm	Average Per Customer	
						Revenue	Therms
2015	$887,146,489	735,308,605	799,627	717,999	$1.18	$645	545
2016	$827,239,737	766,477,413	810,301	727,887	$1.08	$627	579
2017	$902,856,815	928,179,604	822,919	739,604	$0.99	$685	690
2018	$811,179,898	848,006,134	836,280	752,272	$0.99	$602	605
2019	$839,952,672	924,853,643	848,999	764,000	$0.94	$623	662
2020	$847,517,725	863,769,772	862,000	776,893	$1.04	$641	619
2021	$940,933,212	884,431,751	868,966	784,658	$1.09	$680	626
2022	$1,121,782,260	985,665,487	882,329	797,325	$1.19	$787	660
2023	$1,265,010,613	959,517,968	889,034	803,747	$1.46	$915	626
2024	$1,211,228,238	913,534,080	895,759	810,138	$1.46	$874	600

Avista Utilities – Oregon Natural Gas

Ten-Year Summary
Selected Statistics

	Total			Residential			
	Revenue from Natural Gas Sales	Therms of Natural Gas Sold	Average Number of Customers	Average Number of Customers	Revenue Per Therm	Average Per Customer Revenue	Average Per Customer Therms
2015	$166,153,077 [A]	74,327,462	99,078	87,590	$1.32	$650	493
2016	$156,148,758 [A]	78,262,472	99,343	87,644	$1.27	$649	511
2017	$160,211,059 [A]	90,439,615	100,620	88,820	$1.21	$716	591
2018	$145,242,892 [A]	83,914,563	101,966	90,119	$1.19	$634	534
2019	$144,734,102 [A]	96,220,408	103,270	91,337	$1.08	$634	585
2020	$138,265,946 [A]	95,200,508	104,298	92,304	$1.24	$678	548
2021	$161,312,113 [A]	97,822,436	105,011	93,020	$1.32	$719	544
2022	$177,907,223 [A]	100,383,942	105,865	93,820	$1.52	$860	567
2023	$171,337,357 [A]	105,520,856	106,126	94,092	$1.65	$934	566
2024	$144,378,437 [A]	99,771,696	107,385	95,226	$1.49	$772	517

[A] Total includes unbilled revenues.

Cascade Natural Gas Corporation – Oregon Natural Gas

Ten-Year Summary
Selected Statistics

	Total			Residential			
	Revenue from Natural Gas Sales	Therms of Natural Gas Sold	Average Number of Customers	Average Number of Customers	Revenue Per Therm	Average Per Customer	
						Revenue	Therms
2015	$67,650,227	70,219,483	68,697	58,875	$0.98	$625	637
2016	$63,881,404	75,760,101	70,450	60,483	$0.86	$581	678
2017	$64,274,782	87,939,059	71,897	61,798	$0.76	$575	760
2018	$62,341,033	81,932,331	74,355	64,137	$0.81	$557	687
2019	$67,070,587	92,074,125	76,165	65,860	$0.75	$572	759
2020	$71,820,425	85,383,764	78,009	67,590	$0.85	$599	703
2021	$77,563,145	92,074,125	76,165	65,860	$0.75	$572	759
2022	$96,467,596	97,673,565	81,634	71,034	$1.04	$784	752
2023	$115,075,536	93,482,892	83,033	72,354	$1.28	$900	705
2024	$114,616,801	93,779,424	84,436	73,680	$1.27	$885	697

Northwest Natural Gas Company – Oregon Natural Gas

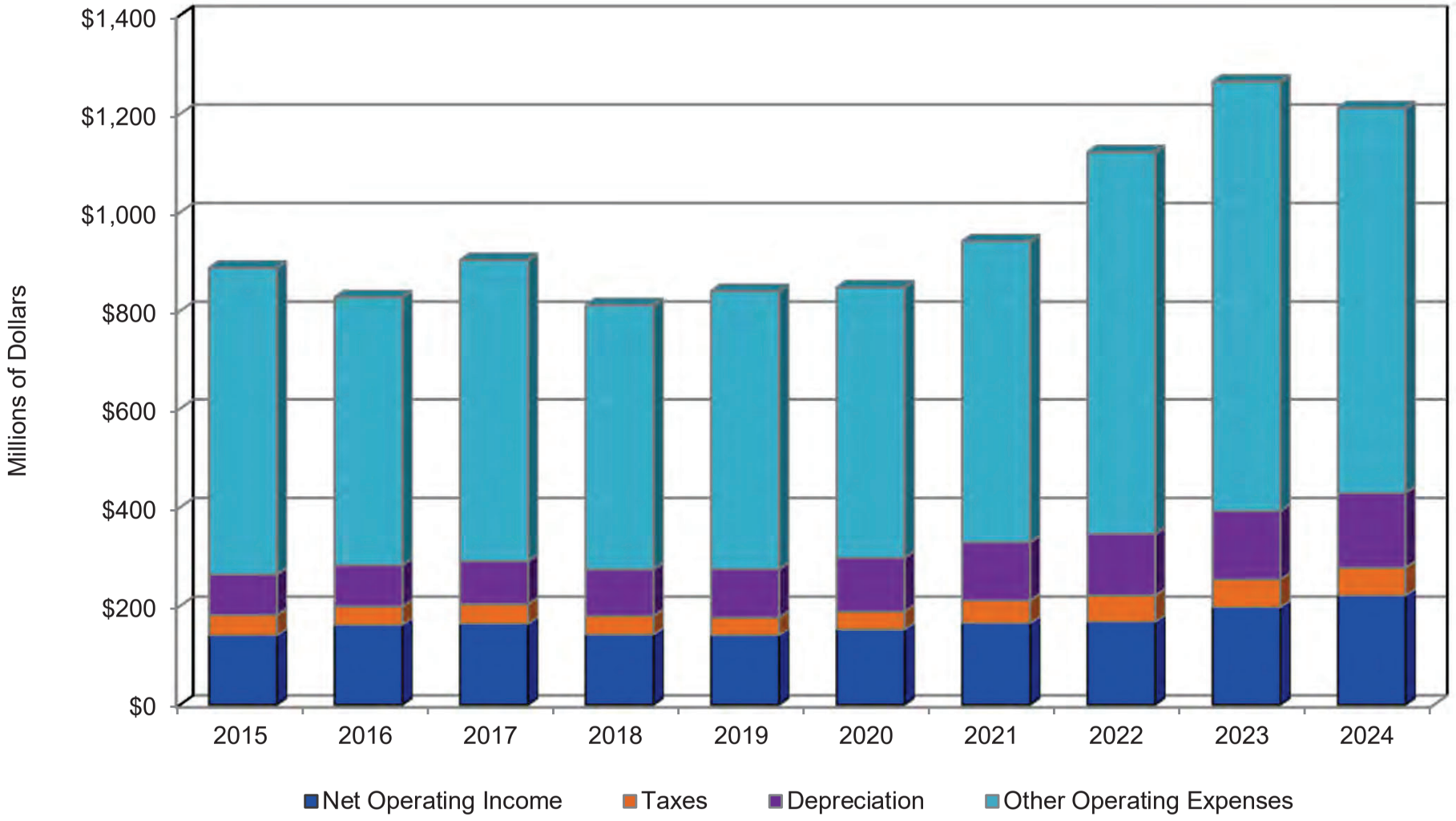
Ten-Year Summary
Selected Statistics

	Total			Residential			
	Revenue from Natural Gas Sales	Therms of Natural Gas Sold	Average Number of Customers	Average Number of Customers	Revenue Per Therm	Average Per Customer	
						Revenue	Therms
2015	$653,343,185	590,761,660	631,852	571,534	$1.19	$646	543
2016	$607,209,575	612,454,840	640,508	579,760	$1.09	$629	578
2017	$678,370,974	749,800,930	650,402	588,986	$0.99	$691	698
2018	$603,595,973	682,159,240	659,959	598,016	$0.99	$601	607
2019	$628,147,983	736,559,110	669,564	606,803	$0.94	$627	663
2020	$637,431,354	683,185,500	679,693	616,999	$1.03	$641	620
2021	$702,057,954	694,535,190	687,790	625,778	$1.10	$686	625
2022	$847,407,441	787,607,980	694,830	632,471	$1.17	$777	663
2023	$978,597,720	760,514,220	699,875	637,301	$1.46	$913	627
2024	$952,233,000	719,982,960	703,938	641,232	$1.48	$887	601

Investor-Owned Natural Gas Utilities in Oregon

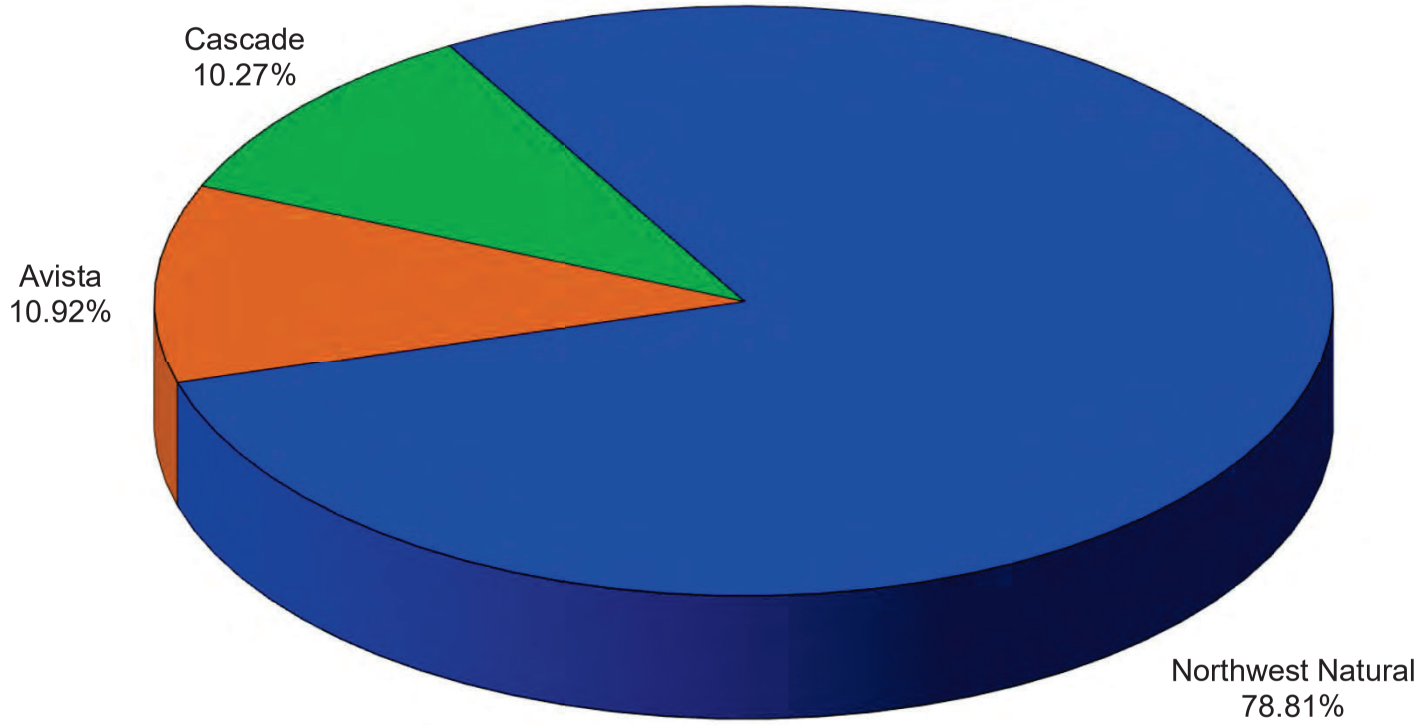
Ten-Year Summary

Distribution of Operating Revenues[A]



[A] Operating Revenues include revenue from Natural Gas Sales, Transportation, and Miscellaneous Utility Operations.

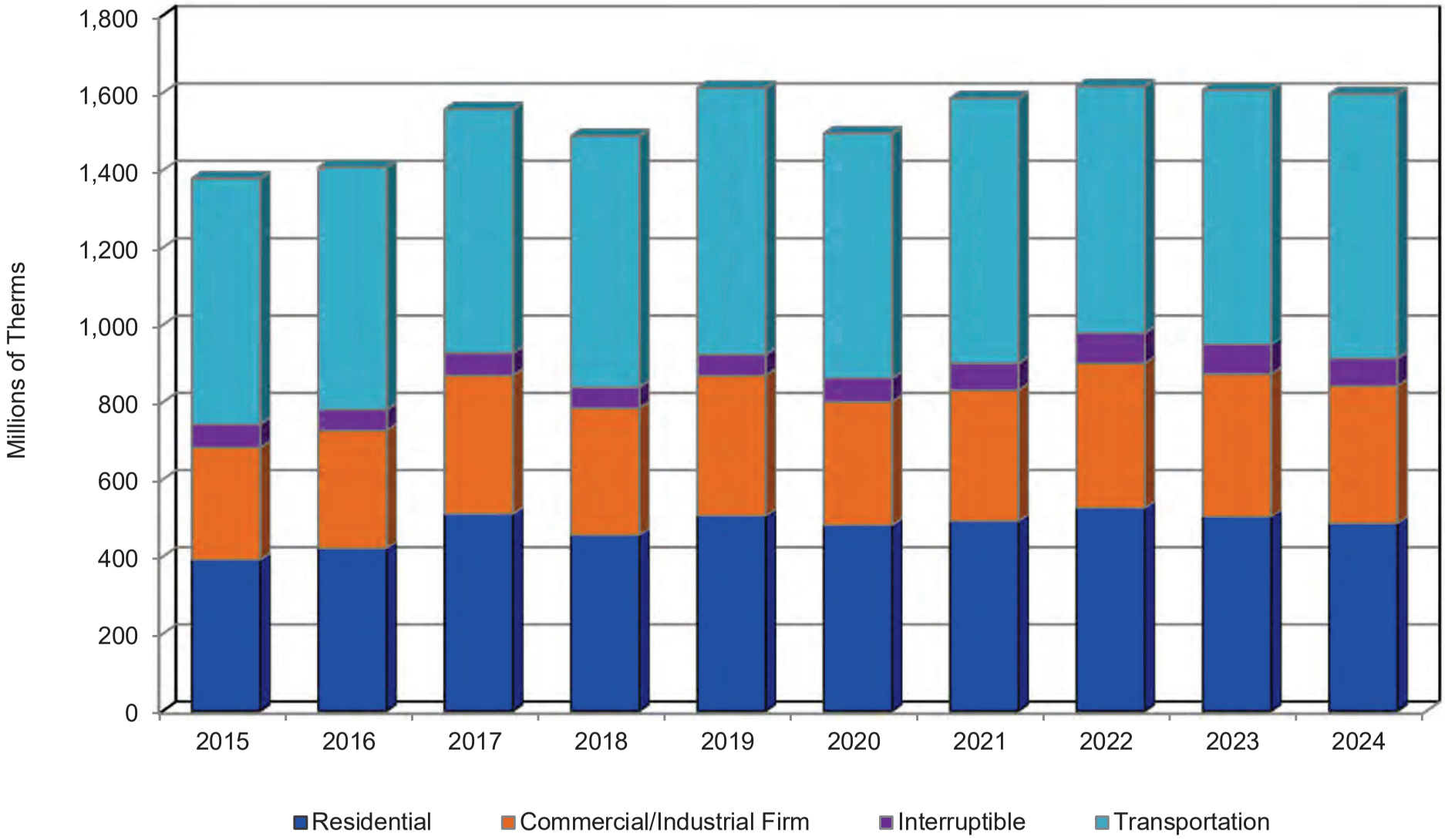
Investor-Owned Natural Gas Utilities in Oregon
Natural Gas Delivered for 2024
(Sales in Therms - Excludes Transportation)



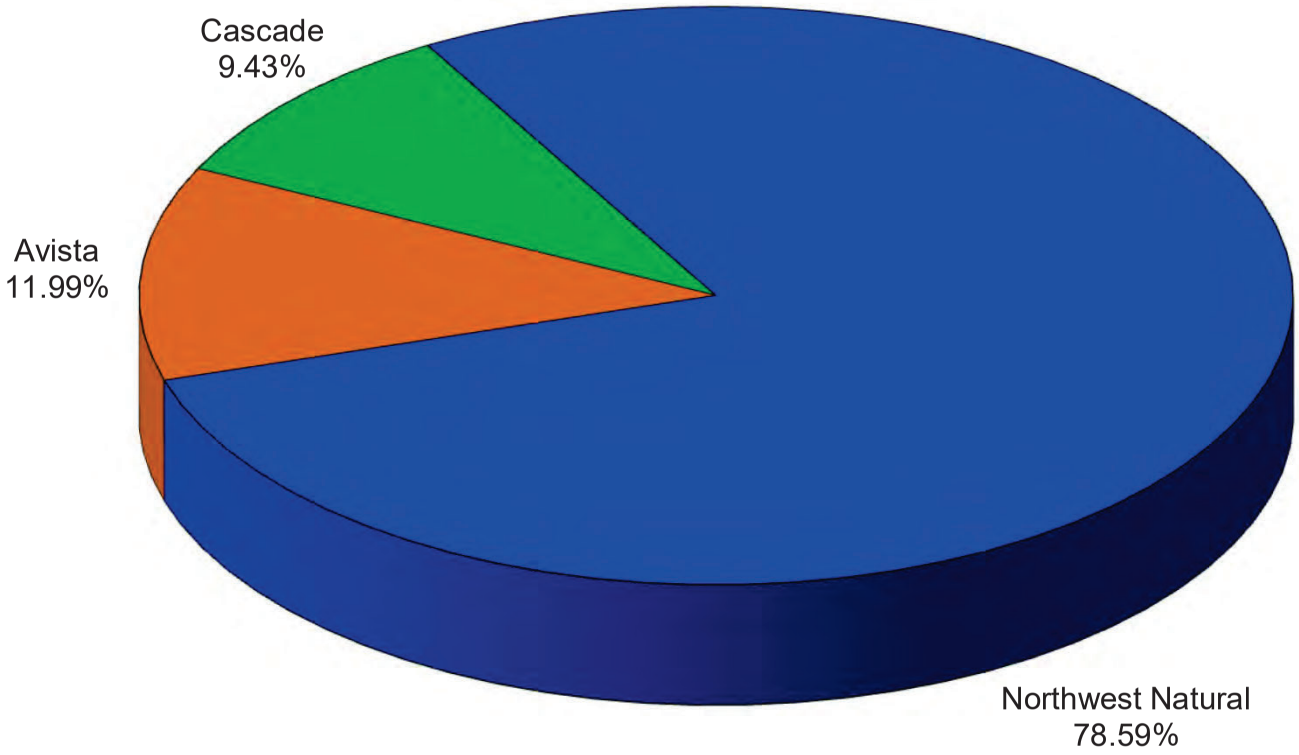
Investor-Owned Natural Gas Utilities in Oregon

Ten-Year Summary

Therms of Natural Gas Delivered in Oregon



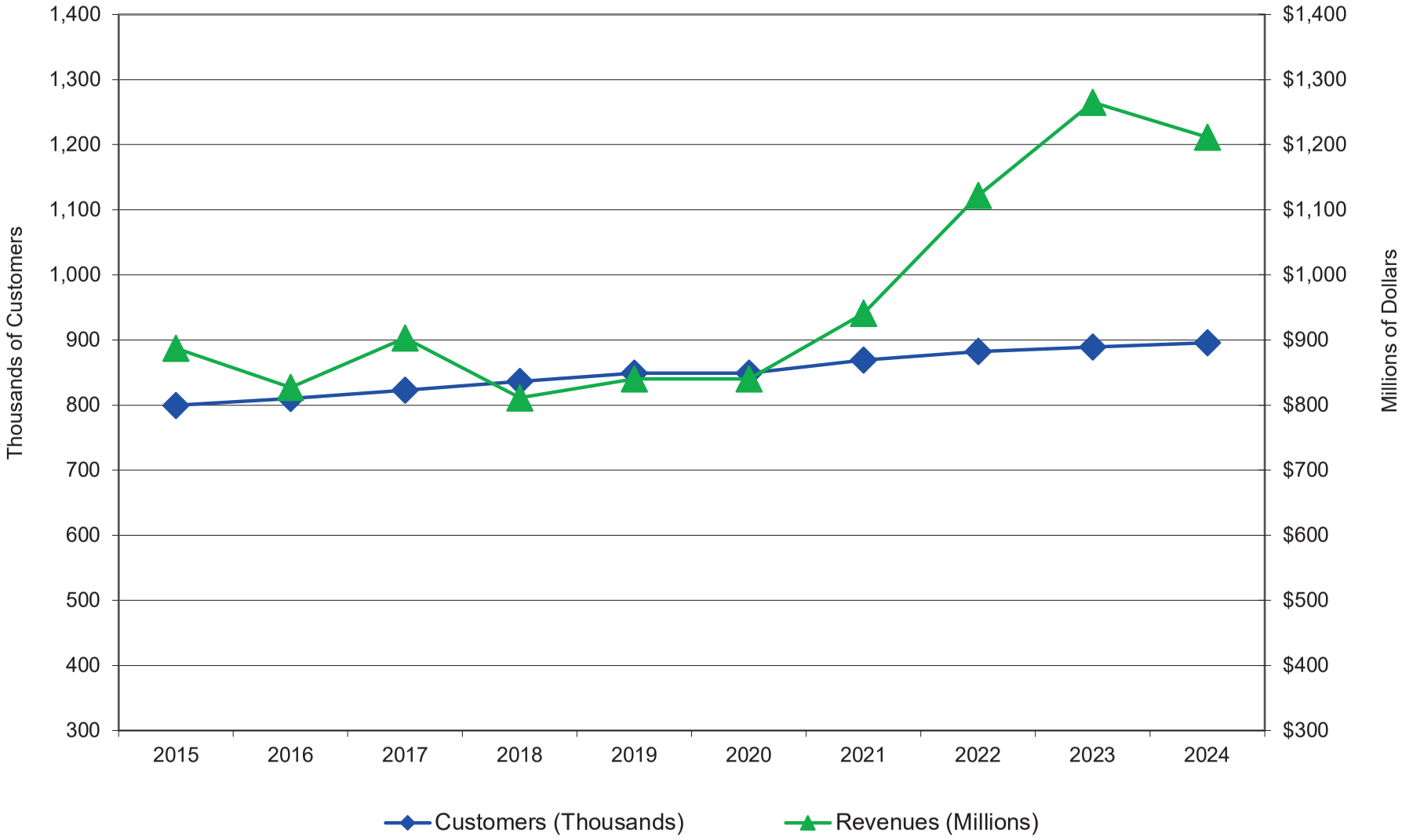
Investor-Owned Natural Gas Utilities in Oregon
Natural Gas Customers for 2024
(Excludes Transportation)



Investor-Owned Natural Gas Utilities in Oregon

Ten-Year Summary

Customers and Revenues from Natural Gas Sales in Oregon



Investor-Owned Natural Gas Utilities in Oregon

Balance Sheet - Total System

Year Ending December 31, 2024

	Avista Utilities	Cascade Natural Gas Corporation	Northwest Natural Gas Company	Investor-Owned Natural Gas Utilities
ASSETS AND OTHER DEBITS				
Utility Plant in Service	$8,212,758,967	$1,601,280,196	$4,769,772,645	$14,583,811,808
Plant Under Construction	206,589,639	35,424,239	130,296,362	372,310,240
Less: Deprec. & Amortization Reserve	2,959,941,113	659,856,596	1,787,466,933	5,407,264,642
Net Utility Plant	$5,459,407,493	$976,847,839	$3,112,602,074	$9,548,857,406
Stored Base-Gas Adjustment	6,992,076	0	25,501,276	32,493,352
Other Property & Investments	317,245,222	9,127,136	174,237,788	500,610,146
Current & Accrued Assets	450,975,214	128,180,858	387,398,472	966,554,544
Deferred Debits	1,153,636,287	409,093,162	462,062,668	2,024,792,117
Total Assets & Other Debits	$7,388,256,292	$1,523,248,995	$4,161,802,278	$13,073,307,565
LIABILITIES AND OTHER CREDITS				
Common Stock	$1,667,222,874	$1,000	$228,868,408	$1,896,092,282
Preferred Stock	0	0	1	1
Premium (Less Discount) on Cap. Stock	0	458,117,553	0	458,117,553
Other Paid-in Capital	(2,732,405)	0	495,152,614	492,420,209
Installments Received on Cap. Stock	0	0	0	0
Less: Capital Stock Expense	55,172,369	0	(4,118,163)	51,054,206
Retained Earnings	831,698,463	80,660,598	613,024,198	1,525,383,259
Unappropriated Undist. Sub. Earnings	39,097,599	0	(2,312,468)	36,785,131
Less: Reacquired Capital Stock	0	0	0	0
Accumulated Other Comprehensive Income	355,480	(730,568)	(7,051,527)	(7,426,615)
Total Proprietary Capital	$2,590,814,380	$538,048,583	$1,323,563,063	$4,452,426,026
Long-Term Debt	2,594,594,851	539,600,000	1,344,700,000	4,478,894,851
Other Noncurrent Liabilities	168,200,104	109,493,850	366,055,325	643,749,279
Current & Accrued Liabilities	629,079,968	85,851,077	485,855,980	1,200,787,025
Customer Advances for Construction	6,506,104	216,848	15,289,973	22,012,925
Accumulated Deferred Invest. Tax Credits	28,097,819	0	0	28,097,819
Other Deferred Credits	33,705,422	2,925,337	4,141,822	40,772,581
Other Regulatory Liabilities	453,484,854	110,306,774	223,540,176	787,331,804
Accumulated Deferred Income Taxes	883,772,790	136,806,526	398,655,939	1,419,235,255
Total Liabilities & Other Credits	$7,388,256,292	$1,523,248,995	$4,161,802,278	$13,073,307,565

Investor-Owned Natural Gas Utilities in Oregon

Income Statement - Total System

Year Ending December 31, 2024

	Avista Utilities	Cascade Natural Gas Corporation	Northwest Natural Gas Company	Investor-Owned Natural Gas Utilities
NET OPERATING INCOME				
Operating Revenues	$605,198,775	$523,440,816	$1,052,977,286	$2,181,616,877
Operation Expenses	$398,290,405	$410,652,487	$622,638,222	$1,431,581,114
Maintenance Expenses	14,615,719	11,014,157	37,268,978	62,898,854
Depreciation & Amortization Expenses	61,586,019	43,280,270	139,395,504	244,261,793
Taxes Other Than Income	37,832,413	48,524,798	73,240,937	159,598,148
Income Taxes	(238,981)	(29,090,478)	30,782,002	1,452,543
Other Operating Expenses	11,466,066	734,067	14,053,393	26,253,526
Total Operating Expenses	$523,551,641	$485,115,301	$917,379,036	$1,926,045,978
Net Operating Income	$81,647,134	$38,325,515	$135,598,250	$255,570,899
Net Other Income & Deductions	[A]	13,576,340	16,747,309	30,323,649
Income Before Interest Charges	[A]	$51,901,855	$152,345,559	$204,247,414
Interest Charges	[A]	26,282,472	57,099,693	83,382,165
AFUDC - Credit	[A]	2,587,047	6,173,100	8,760,147
Income Before Extraordinary Items	[A]	$23,032,336	$89,072,766	$112,105,102
Extraordinary Items	[A]	0	0	0
Net Income	[A]	$23,032,336	$89,072,766	$112,105,102
RETAINED EARNINGS				
Balance, January 1	$784,460,390	$74,667,884	$594,412,433	$1,453,540,707
Net Income	177,598,266	23,032,336	89,072,766	289,703,368
Other Credits	5,000,000	0	0	5,000,000
Dividends	(150,693,583)	(17,039,622)	(72,773,469)	(240,506,674)
Other Debits	0	0	0	0
Appropriated Retained Earnings	(5,000,000)	0	0	(5,000,000)
Other Changes	59,430,989	0	0	59,430,989
Balance, December 31	$870,796,062	$80,660,598	$610,711,730	$1,562,168,390

[A] Details are unavailable.

Investor-Owned Natural Gas Utilities in Oregon

Financial Data - Oregon and Total System

Year Ending December 31, 2024

	Avista Utilities		Cascade Natural Gas Corporation		Northwest Natural Gas Company		Investor-Owned Natural Gas Utilities	
	Oregon	System	Oregon	System	Oregon	System	Oregon	System
OPERATING REVENUES ($000s)								
Revenues from Natural Gas Sales	$136,779	$555,298	$109,309	$479,011	$880,426	$985,325	$1,126,515	$2,019,634
Revenues from Transportation	2,662 [B]	11,680	4,623	43,123	$37,899	40,224	45,184	95,027
Other Misc. Operating Revenues	4,937	38,221	684	1,307	$33,908	27,431	39,529	66,959
Total Operating Revenues	$144,378	$605,199	$114,617	$523,441	$952,233	$1,052,981	$1,211,228	$2,181,620
OPERATING EXPENSES ($000s)								
Production	$55,254	$299,407	$66,657	$333,075	$307,353	$339,375	$429,264	$971,858
Distribution & Transmission	7,886	25,691	6,866	29,540	64,664	72,726	79,416	127,957
Customer Accounts	3,302	10,762	2,432	9,752	0 [C]	0	5,734	20,514
Customer Service & Information	6,334	29,263	216	12,255	0 [C]	0	6,550	41,518
Sales	1	1	37	141	0 [C]	0	38	141
Administrative & General	14,933	47,782	9,343	36,903	237,207	264,337	261,482	349,022
Total Operating Expenses	$87,709	$412,906	$85,551	$421,667	$609,224	$676,438	$782,484	$1,511,010
OTHER REVENUE DEDUCTIONS ($000s)								
Depreciation & Amortization	$18,994	$61,586	$11,159	$43,280	$121,274	$137,043	$151,428	$241,910
Taxes	11,991	37,593	9,849	19,434	34,690 [D]	41,325 [D]	56,530	98,353
Miscellaneous Debits and Credits	0	11,466	0	734	0	0	0	12,200
Total Revenue Deductions	$30,986	$110,646	$21,008	$63,449	$155,964	$178,369	$207,958	$352,463
Total Expenses and Deductions	$118,695	$523,552	$106,559	$485,115	$765,188	$854,806	$990,442	$1,863,473
NET OPERATING INCOME ($000s)	$25,684	$81,647	$8,058	$38,326	$187,045	$198,174	$220,786	$318,147

[A] Excludes Schedule 90, Schedule H, Schedule 4, and Non-Recoverables.

[B] Includes unbilled revenues.

[C] O&M expenses are consolidated into Administrative & General.

[D] Excludes Property Tax.

Investor-Owned Natural Gas Utilities in Oregon

Gas Purchase and Delivery Statistics - Oregon

Year Ending December 31, 2024

	Avista Utilities	Cascade Natural Gas Corporation	Northwest Natural Gas Company	Investor-Owned Natural Gas Utilities
PURCHASE STATISTICS (therms)				
Natural Gas Sales	99,771,696	93,779,424	719,982,960	913,534,080
Natural Gas Used by Company	13,944	30,702	5,419,450	5,464,096
Natural Gas Delivered to Storage - Net	340,780	0	4,991,400	5,332,180
Sales for Resale	89,735,550	0	0	89,735,550
Losses and Billing Delay	(1,265,690)	2,391,738	11,081,194	12,207,242
Total Natural Gas Disbursements	188,596,280	96,201,864	741,475,004	1,026,273,148
REVENUE BY SERVICE CLASS				
Residential Sales	$73,490,743	$65,197,465	$568,969,537	$707,657,745
Commercial & Industrial Sales:				
Firm Sales	38,157,874	44,111,941 [A]	293,799,243	376,069,058
Interruptible Sales	6,932,058	0	28,680,418	35,612,476
Transportation and Storage	2,662,193	4,622,913	37,898,682	45,183,788
Total Revenue	$121,242,868	$113,932,319	$929,347,880	$1,164,523,067
NATURAL GAS DELIVERED (therms)				
Residential Sales	49,261,114	51,353,016	385,309,954	485,924,084
Commercial & Industrial Sales:				
Firm Sales	32,337,262	42,426,408 [A]	281,754,524	356,518,194
Interruptible Sales	18,173,319	0	52,689,891	70,863,210
Transportation	31,818,418	301,334,788	349,809,181	682,962,387
Total Therms	131,590,113	395,114,212	1,069,563,550	1,596,267,875
AVERAGE NUMBER OF CUSTOMERS				
Residential Sales	95,226	73,680	641,232	810,138
Commercial & Industrial Sales:				
Firm Sales	12,112	10,756 [A]	62,613	85,481
Interruptible Sales	47	0	93	140
Transportation	31	35	278	344
Total Customers	107,416	84,471	704,216	896,103
REVENUE PER THERM ($)				
Residential Sales	1.49	1.27	1.48	1.46
Commercial & Industrial Sales:				
Firm Sales	1.18	1.04 [A]	1.04	1.05
Interruptible Sales	0.38	N/A	0.54	0.50
Transportation	0.08	0.02	0.11	0.07
RESIDENTIAL AVERAGE PER CUSTOMER				
Revenue	$772	$885	$887	$874
Therm Consumption	517	697	601	600

[A] Includes both Firm and Interruptable Sales.

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Telecommunications

Foreword to Telecommunications Utilities and Cooperatives

This section contains Oregon telecommunications data from annual reports filed by 30 Incumbent Local Exchange carriers (ILECs).[1] The ILECs consist of telecommunications utilities and cooperatives. Eleven of the thirty ILECs are Telecommunication Cooperatives, fourteen are Small Telecommunication Utilities, and five are classified as Large Telecommunication Utilities since they are either affiliated with CenturyLink or Ziply Fiber.

The ILECs' total 2024 Gross Oregon Operating Revenues were $736 million, a 2.0 percent decrease from the $751 million they generated in 2023. As measured by Gross Oregon Operating Revenues, CenturyLink (including affiliates) had a 57.9 percent share of the ILEC market and Ziply Fiber (including affiliates) had 25.0 percent. The remaining ILECs had 17.1 percent of the ILEC market. As measured by Total lines, CenturyLink provisioned 71.3 percent of the market served by ILECs and Ziply Fiber served 18.6 percent. The remaining ILECs served 10.1 percent. Because CenturyLink and Ziply Fiber account for the majority of the lines and revenues, they strongly influence the graphs and statistical data.

The Oregon Public Utility Commission implemented the Oregon Universal Service Fund (OUSF) program in 2001 to ensure that basic service is available to customers at reasonable and affordable rates in high-cost areas. In 2021, the OUSF expanded to include both wireless and VoIP providers, and in 2024, a total of 326 certificated providers (TSPs) contributed $28.4 million. For that same year, the fund distributed $27.9 million to 32 eligible TSPs that provide basic local telephone service in the high-cost areas.

[1] CenturyTel of Eastern Oregon and CenturyTel of Oregon are treated as one entity - CenturyTel, Inc.

Index to Telecommunications Utilities and Cooperatives

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- Small Telecommunications Utilities 76
- Large Telecommunications Utilities 82
- Total ILECs 84

Oregon Universal Service Fund 87

Telecommunications Cooperatives

Beaver Creek Cooperative Telephone Company
Canby Telephone Company
Clear Creek Mutual Telephone Company
Colton Telephone Company
Gervais Telephone Company
Molalla Telephone Company
Monitor Cooperative Telephone Company
Pioneer Telephone Cooperative
St. Paul Cooperative Telephone Company
Scio Mutual Telephone Company
Stayton Cooperative Telephone Company

Small Telecommunications Utilities

Asotin Telephone Company
Cascade Utilities, Inc.
Eagle Telephone System, Inc.
Helix Telephone Company
Home Telephone Company
Monroe Telephone Company
Nehalem Telecommunications, Inc.
North-State Telephone Company
Oregon Telephone Corporation
Oregon-Idaho Utilities, Inc.
People's Telephone Company
Pine Telephone System, Inc.
Roome Telecommunications, Inc.
Trans-Cascades Telephone Company

Large Telecommunications Utilities

CenturyTel, Inc.
Qwest Corporation
United Telephone Company of the Northwest
Ziply Fiber Northwest, LLC
Ziply Fiber of Oregon, LLC

Affiliated ILEC Groupings

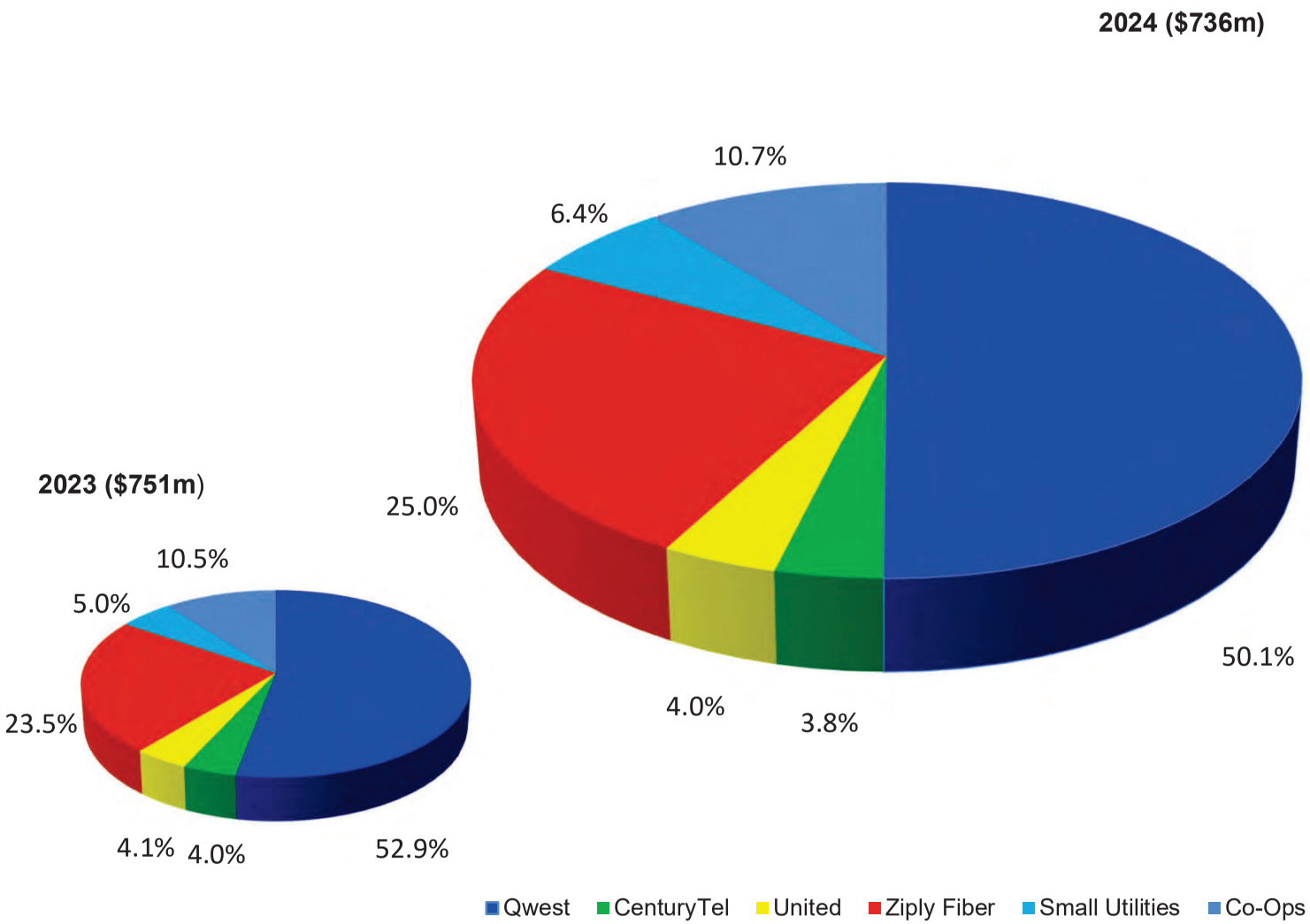
Non-Rural Telecommunication Companies	Rural Telecommunication Companies
CenturyLink*	**Cascade Utilities, Inc.***
CenturyTel, Inc.	Trans-Cascades Telephone Company
Qwest Corporation dba CenturyLink QC	
United Telephone Company of the Northwest	
Ziply Fiber Northwest LLC*	**Oregon Telephone Corporation***
Ziply Fiber of Oregon, LLC	North-State Telephone Company
	Home Telephone Company
	Pine Telephone System, Inc.
	Helix Telephone Company
	Stayton Cooperative Telephone Company*
	Peoples Telephone Company

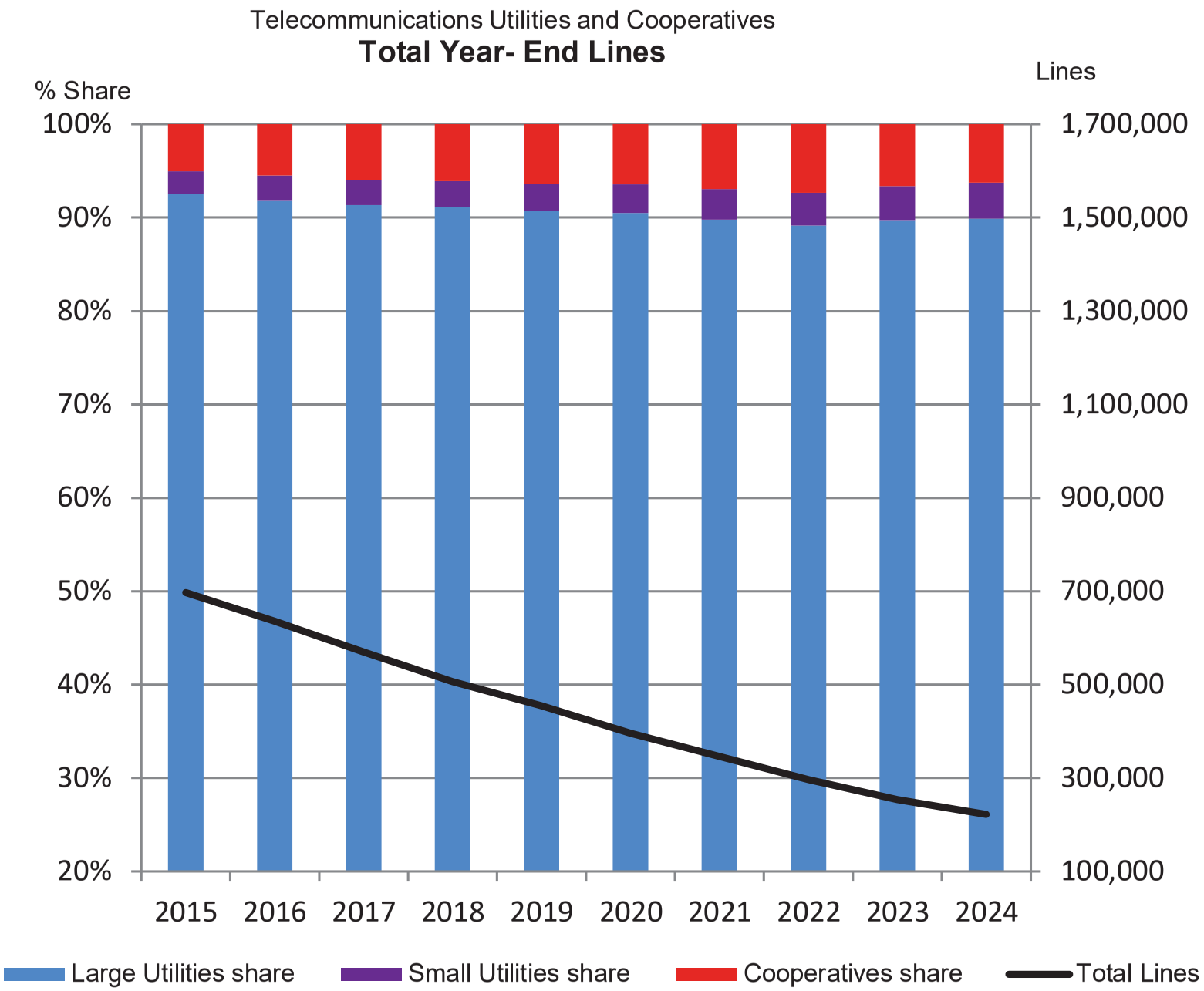
* Parent company or largest of a group of family-owned companies.

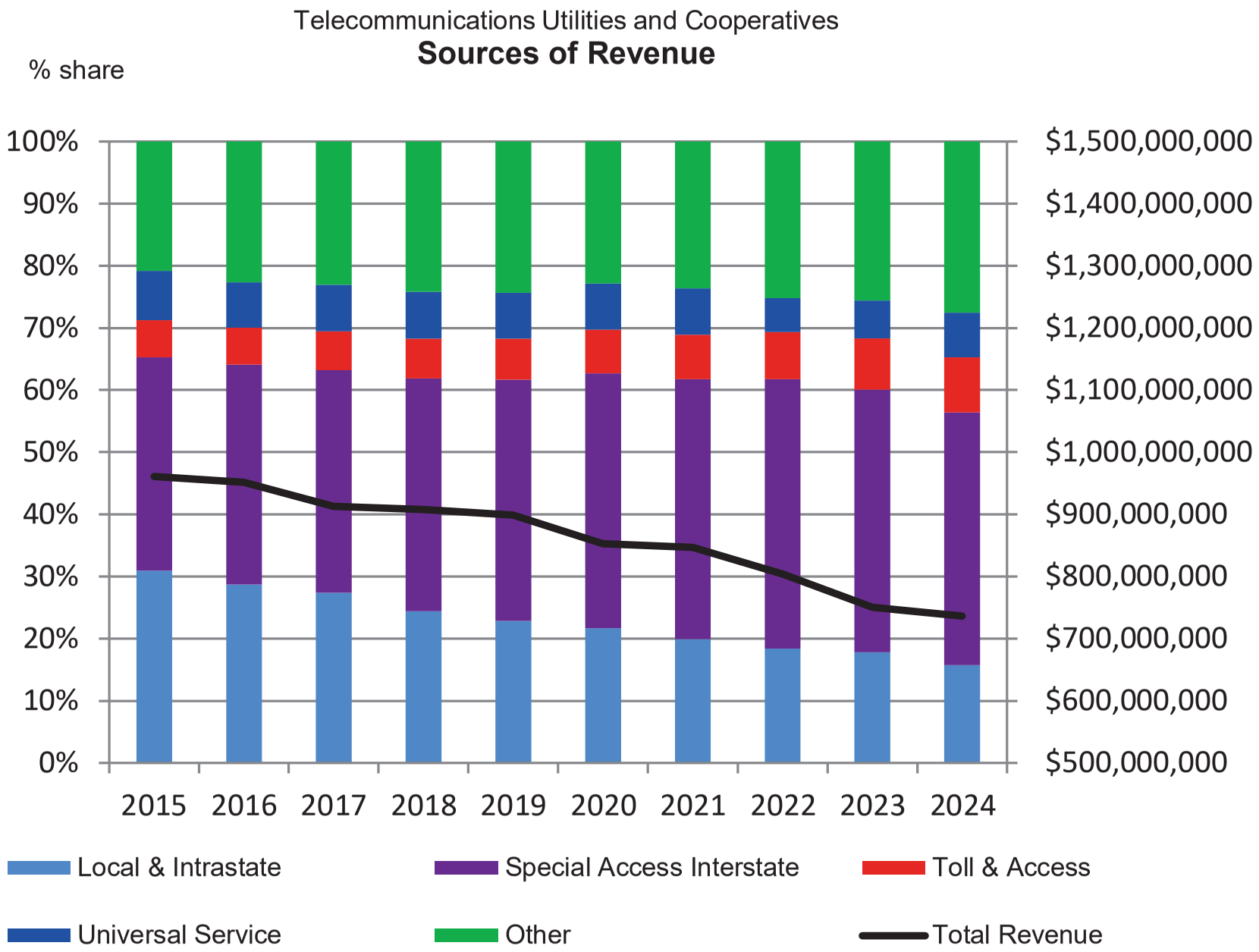
Telecommunications Utilities and Cooperatives - Total Oregon

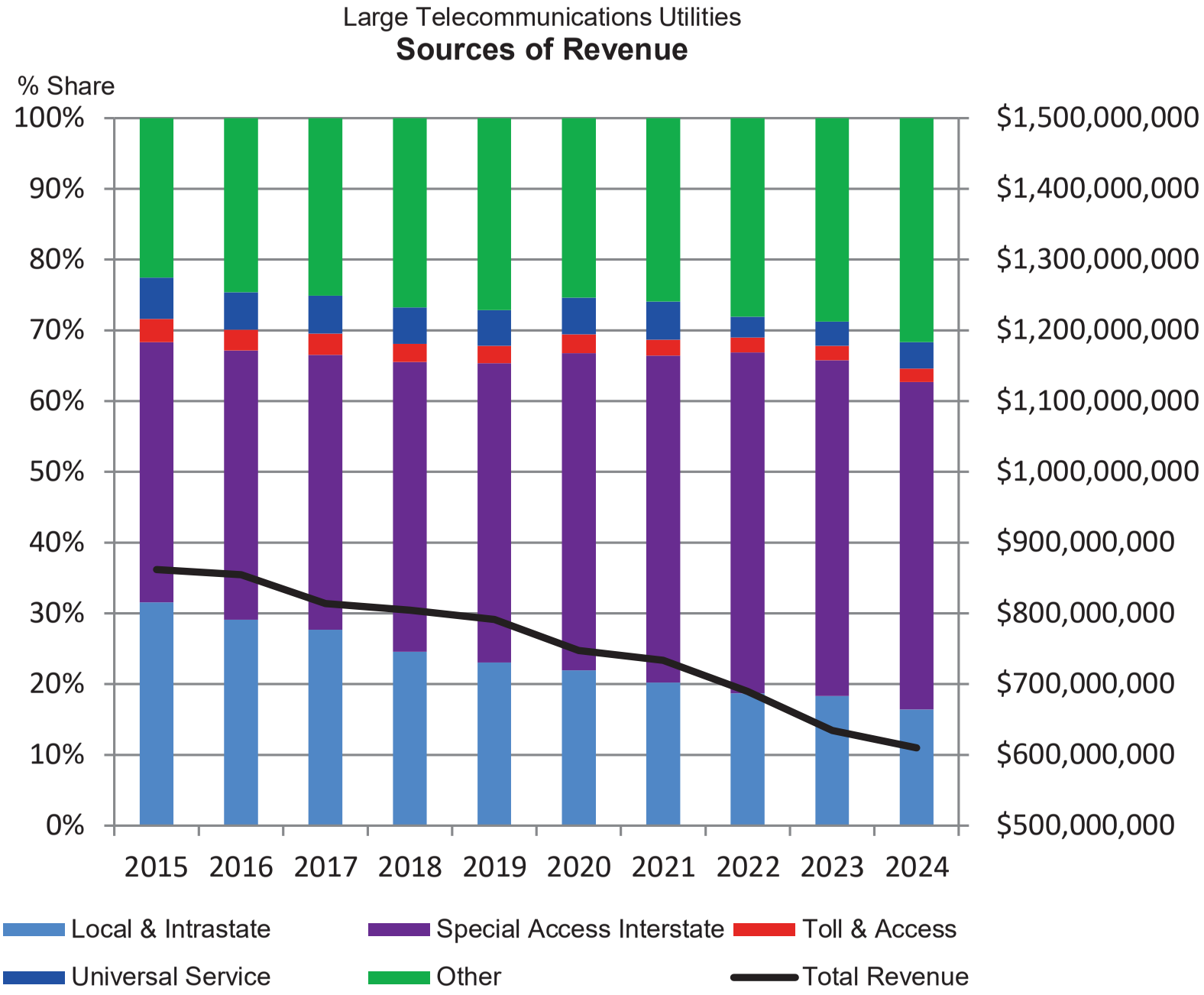
Market Share

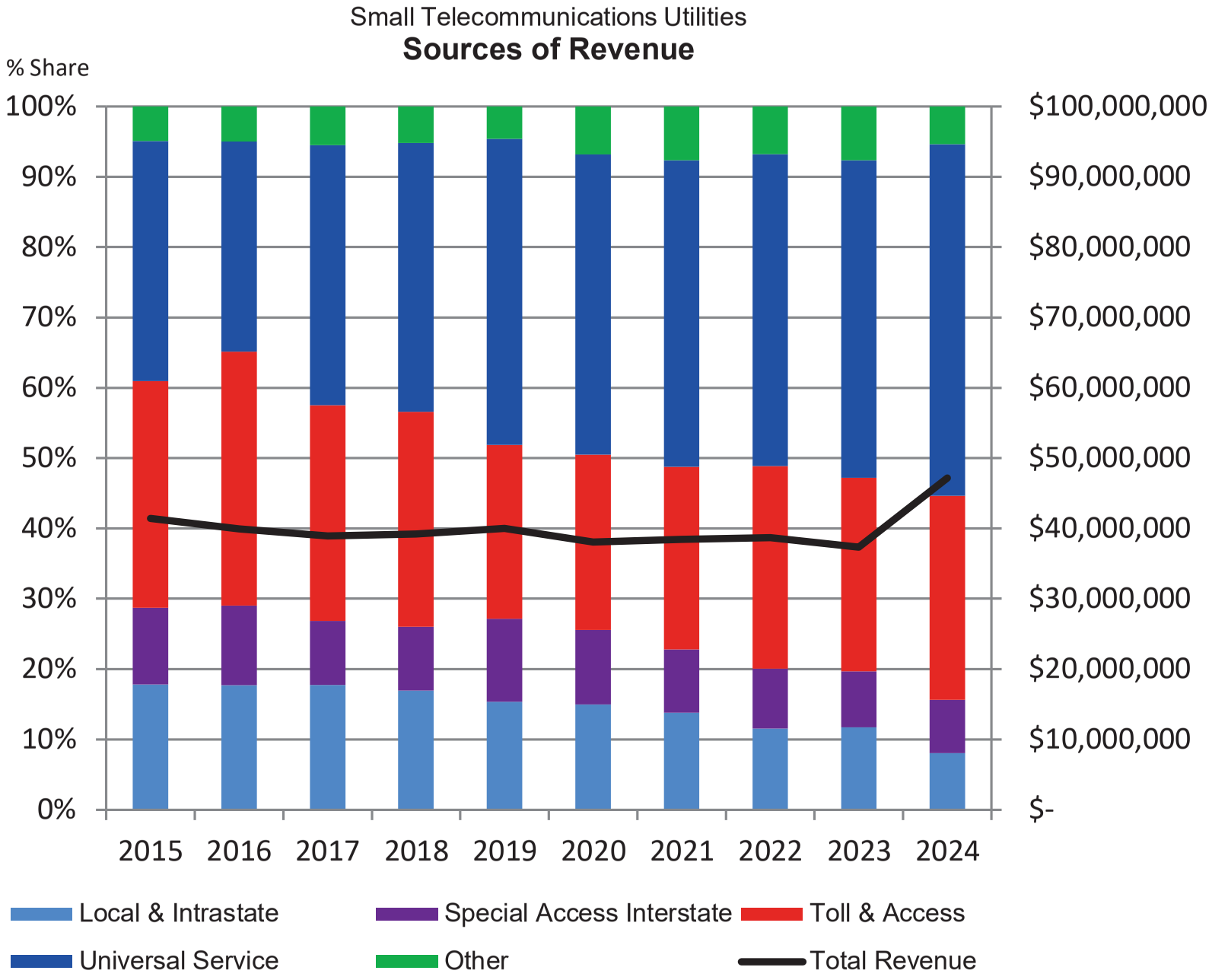
(Gross Operating Revenues)




Telecommunications Utilities and Cooperatives
Total Year- End Lines
% Share
Lines
100%
90%
80%
70%
60%
50%
40%
30%
20%
1,700,000
1,500,000
1,300,000
1,100,000
900,000
700,000
500,000
300,000
100,000
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
Large Utilities share
Small Utilities share
Cooperatives share
Total Lines


Telecommunications Utilities and Cooperatives
Sources of Revenue
% share
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
$1,500,000,000
$1,400,000,000
$1,300,000,000
$1,200,000,000
$1,100,000,000
$1,000,000,000
$900,000,000
$800,000,000
$700,000,000
$600,000,000
$500,000,000
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
Local & Intrastate
Special Access Interstate
Toll & Access
Universal Service
Other
Total Revenue


Large Telecommunications Utilities
Sources of Revenue
% Share
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
$1,500,000,000
$1,400,000,000
$1,300,000,000
$1,200,000,000
$1,100,000,000
$1,000,000,000
$900,000,000
$800,000,000
$700,000,000
$600,000,000
$500,000,000
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
Local & Intrastate
Special Access Interstate
Toll & Access
Universal Service
Other
Total Revenue


Small Telecommunications Utilities
Sources of Revenue
% Share
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
$100,000,000
$90,000,000
$80,000,000
$70,000,000
$60,000,000
$50,000,000
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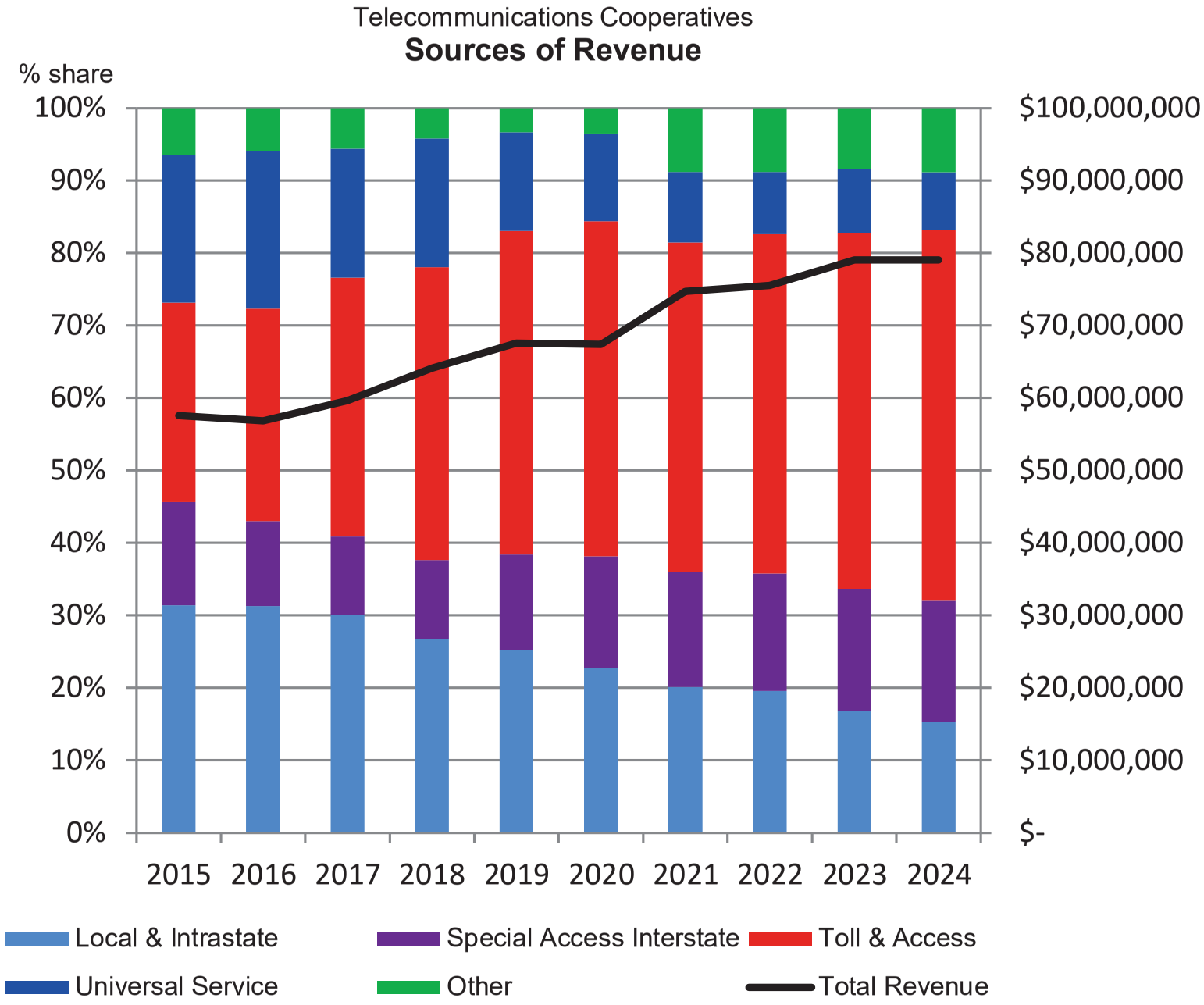
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
Local & Intrastate
Special Access Interstate
Toll & Access
Universal Service
Other
Total Revenue


Telecommunications Cooperatives
Sources of Revenue
% share
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
$100,000,000
$90,000,000
$80,000,000
$70,000,000
$60,000,000
$50,000,000
$40,000,000
$30,000,000
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$-
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
Local & Intrastate
Special Access Interstate
Toll & Access
Universal Service
Other
Total Revenue

Telecommunications Utilities and Cooperatives

TEN-YEAR SUMMARY
END-OF-YEAR REVENUES AND LINES

	Revenues ($000s)									
	Total [A]	Local & Special Access Intrastate	Special Access Interstate	Toll & Switched Access	Universal Service [C]	Other Revenues [D]	Residential Lines [B]	Business Lines [B]	UNE NACs [B]	Total
2015	$960,785	$297,327	$330,061	$57,080	$75,936	$200,380	379,673	234,010	83,560	697,243
2016	$951,199	$273,528	$336,291	$56,169	$69,308	$215,904	341,692	215,743	78,211	635,646
2017	$912,539	$249,992	$326,556	$57,484	$68,379	$210,128	299,612	199,595	70,424	569,631
2018	$907,879	$221,505	$339,943	$58,435	$68,199	$219,799	261,493	181,469	64,015	506,977
2019	$898,884	$205,471	$348,648	$59,221	$66,736	$218,808	229,500	165,215	59,935	454,650
2020	$852,734	$185,202	$349,346	$60,233	$63,096	$194,857	190,738	153,175	52,059	395,972
2021	$846,699	$168,809	$354,047	$60,449	$63,458	$199,936	164,182	138,569	43,660	346,411
2022	$803,730	$148,075	$348,020	$60,995	$44,015	$202,625	140,824	120,376	36,084	297,284
2023	$750,764	$133,694	$317,502	$61,910	$45,574	$192,084	118,552	103,574	31,963	254,089
2024	$736,233	$115,765	$299,510	$65,406	$52,789	$202,762	99,466	97,983	24,587	222,036

[A] Total revenues are shown net of uncollectibles and include billing and collection, network access, directories, and miscellaneous revenues. Adjustments have been made for changes in accounting methods regarding collections of OUSF and imputed directory revenue.

[B] The Residential line count is taken directly from the Annual Report Form O, Schedule S-1. The Business line count is taken from the Annual Report Form O and is the total of Business Lines, PBX Trunks, Centrex-Co Lines, and ISDN "B" Channels. The Unbundled Network Elements (UNE) Network Access Channels (NACS) line count is taken directly from the "UNE NACs" of Form O.

[C] Universal Service includes both State and Federal support as reported on the annual Form O.

[D] Other Revenues include Federal USF Collections, Directory Revenue, Carrier Billing & Collections, Non Regulatory Revenues, Misc. Revenues, and Uncollectible Revenues.

CenturyTel[E]

TEN-YEAR SUMMARY
END-OF-YEAR REVENUES AND LINES

	Revenues ($000's)									
	Total [A]	Local & Special Access Intrastate	Special Access Interstate	Toll & Switched Access	Universal Service [C]	Other Revenues [D]	Residential Lines [B]	Business Lines [B]	UNE NACs [B]	Total
2015	$43,783	$19,549	$9,890	$1,234	$9,607	$3,503	30,397	10,000	0	40,397
2016	$43,353	$19,100	$10,183	$996	$9,455	$3,620	28,735	9,517	0	38,252
2017	$41,477	$17,991	$10,530	$836	$9,239	$2,880	23,375	8,748	0	32,123
2018	$39,293	$14,637	$7,605	$707	$9,146	$7,199	18,458	8,051	0	26,509
2019	$37,609	$13,217	$8,287	$656	$8,796	$6,652	15,791	7,420	0	23,211
2020	$36,708	$11,686	$9,671	$680	$8,559	$6,112	14,063	6,724	0	20,787
2021	$35,650	$9,502	$11,375	$558	$8,633	$5,582	12,382	6,097	0	18,479
2022	$30,385	$8,730	$13,196	$431	$3,076	$4,952	10,704	5,597	0	16,301
2023	$30,144	$7,695	$14,477	$303	$3,546	$4,123	8,994	4,742	0	13,736
2024	$27,623	$6,593	$13,398	$233	$3,757	$3,642	7,433	4,049	0	11,482

[A] Total revenues are shown net of uncollectibles and include billing and collection, network access, directories, and miscellaneous revenues. Adjustments have been made for changes in accounting methods regarding collections of OUSF and imputed directory revenue.

[B] The Residential line count is taken directly from the Annual Report Form O, Schedule S-1. The Business line count is taken from the Annual Report Form O and is the total of Business Lines, PBX Trunks, Centrex-Co Lines, and ISDN "B" Channels. The Unbundled Network Elements (UNE) Network Access Channels (NACS) line count is taken directly from the "UNE NACs" of Form O.

[C] Universal Service includes both State and Federal support as reported on the annual Form O.

[D] Other Revenues include Federal USF Collections, Directory Revenue, Carrier Billing & Collections, Non Regulatory Revenues, Misc. Revenues, and Uncollectible Revenues.

[E] CenturyTel of Eastern Oregon and CenturyTel of Oregon are treated as one entity for setting Oregon intrastate rates.

Qwest Corporation dba CenturyLink QC

TEN-YEAR SUMMARY
END-OF-YEAR REVENUES AND LINES

	Revenues ($000's)									
	Total [A]	Local & Special Access Intrastate	Special Access Interstate	Toll & Switched Access	Universal Service [C]	Other Revenues [D]	Residential Lines [B]	Business Lines [B]	UNE NACs [B]	Total
2015	$537,726	$172,059	$255,467	$15,467	$20,880	$73,853	194,747	145,444	65,318	405,509
2016	$533,465	$153,998	$264,288	$13,442	$19,594	$82,143	168,917	132,486	61,433	362,836
2017	$507,897	$137,866	$256,215	$13,066	$19,044	$81,705	146,872	120,808	55,341	323,021
2018	$511,613	$123,166	$271,583	$11,229	$18,536	$87,099	127,870	108,930	50,201	287,001
2019	$506,369	$114,065	$278,928	$10,761	$17,791	$84,824	111,340	97,892	46,217	255,449
2020	$478,578	$103,893	$271,516	$10,975	$16,716	$75,479	100,166	88,286	40,560	229,012
2021	$479,050	$97,170	$278,431	$9,574	$16,733	$77,143	85,483	79,230	36,573	201,286
2022	$446,287	$82,371	$270,884	$7,986	$8,583	$76,464	73,949	68,577	31,671	174,197
2023	$397,474	$73,052	$244,473	$6,591	$9,326	$64,032	63,989	58,668	26,387	149,044
2024	$368,812	$62,311	$227,436	$5,611	$9,787	$63,666	54,696	60,574	22,294	137,564

[A] Total revenues are shown net of uncollectibles and include billing and collection, network access, directories, and miscellaneous revenues. Adjustments have been made for changes in accounting methods regarding collections of OUSF and imputed directory revenue.

[B] The Residential line count is taken directly from the Annual Report Form O, Schedule S-1. The Business line count is taken from the Annual Report Form O and is the total of Business Lines, PBX Trunks, Centrex-Co Lines, and ISDN "B" Channels. The Unbundled Network Elements (UNE) Network Access Channels (NACS) line count is taken directly from the "UNE NACs" of Form O.

[C] Universal Service includes both State and Federal support as reported on the annual Form O.

[D] Other Revenues include Federal USF Collections, Directory Revenue, Carrier Billing & Collections, Non Regulatory Revenues, Misc. Revenues, and Uncollectible Revenues.

United Telephone Company of the Northwest

TEN-YEAR SUMMARY
END-OF-YEAR REVENUES AND LINES

	Revenues ($000's)									
	Total [A]	Local & Special Access Intrastate	Special Access Interstate	Toll & Switched Access	Universal Service [C]	Other Revenues [D]	Residential Lines [B]	Business Lines [B]	UNE NACs [B]	Total
2015	$48,600	$15,503	$13,872	$1,564	$4,487	$13,174	21,494	9,418	1,270	32,182
2016	$49,545	$15,470	$14,747	$1,437	$4,372	$13,520	20,352	8,600	1,122	30,074
2017	$48,136	$15,096	$16,328	$1,210	$4,451	$11,050	16,713	7,849	1,115	25,677
2018	$44,469	$12,747	$15,837	$1,068	$4,392	$10,424	12,902	7,234	1,156	21,292
2019	$42,573	$11,480	$15,289	$1,041	$4,639	$10,123	10,727	6,643	1,060	18,430
2020	$41,758	$10,491	$22,069	$937	$4,453	$3,808	9,362	6,060	992	16,414
2021	$41,198	$9,519	$21,403	$898	$4,572	$4,805	8,277	5,542	844	14,663
2022	$38,053	$8,930	$21,414	$802	$2,541	$4,366	7,044	5,155	738	12,937
2023	$30,464	$7,935	$15,336	$693	$2,840	$3,660	5,850	4,583	662	11,095
2024	$29,736	$6,869	$16,064	$616	$2,911	$3,276	4,863	3,892	591	9,346

[A] Total revenues are shown net of uncollectibles and include billing and collection, network access, directories, and miscellaneous revenues. Adjustments have been made for changes in accounting methods regarding collections of OUSF and imputed directory revenue.

[B] The Residential line count is taken directly from the Annual Report Form O, Schedule S-1. The Business line count is taken from the Annual Report Form O and is the total of Business Lines, PBX Trunks, Centrex-Co Lines, and ISDN "B" Channels. The Unbundled Network Elements (UNE) Network Access Channels (NACS) line count is taken directly from the "UNE NACs" of Form O.

[C] Universal Service includes both State and Federal support as reported on the annual Form O.

[D] Other Revenues include Federal USF Collections, Directory Revenue, Carrier Billing & Collections, Non Regulatory Revenues, Misc. Revenues, and Uncollectible Revenues.

Ziply Fiber of Oregon , LLC

TEN-YEAR SUMMARY
END-OF-YEAR REVENUES AND LINES

	Revenues ($000's)									
	Total [A]	Local & Special Access Intrastate	Special Access Interstate	Toll & Switched Access	Universal Service [C]	Other Revenues [D]	Residential Lines [B]	Business Lines [B]	UNE NACs [B]	Total
2015	$8,631	$3,297 [E]	$406	$391	$797 [E]	$3,739	5,713	1,733	0	7,446
2016	$8,798	$2,976	$477	$301	$736	$4,309	5,121	1,604	0	6,725
2017	$7,952	$2,662	$438	$266	$684	$3,902	4,665	1,392	0	6,057
2018	$7,254	$2,396	$313	$233	$646	$3,665	4,311	1,286	0	5,597
2019	$7,170	$2,309	$338	$220	$684	$3,619	3,991	1,117	0	5,108
2020	$6,878	$2,239	$277	$704	$1,431	$2,226	3,402	1,026	0	4,428
2021	$6,376	$1,798	$201	$255	$1,826	$2,296	3,044	773	0	3,817
2022	$5,086	$1,608	$223	$193	$488	$2,573	2,479	649	0	3,128
2023	$5,040	$1,533	$285	$181	$463	$2,578	2,003	502	0	2,505
2024	$4,925	$1,294	$349	$88	$768	$2,427	1,612	391	0	2,003

[A] Total revenues are shown net of uncollectibles and include billing and collection, network access, directories, and miscellaneous revenues. Adjustments have been made for changes in accounting methods regarding collections of OUSF and imputed directory revenue.

[B] The Residential line count is taken directly from the Annual Report Form O, Schedule S-1. The Business line count is taken from the Annual Report Form O and is the total of Business Lines, PBX Trunks, Centrex-Co Lines, and ISDN "B" Channels. The Unbundled Network Elements (UNE) Network Access Channels (NACS) line count is taken directly from the "UNE NACs" of Form O.

[C] Universal Service includes both State and Federal support as reported on the annual Form O.

[D] Other Revenues include Federal USF Collections, Directory Revenue, Carrier Billing & Collections, Non Regulatory Revenues, Misc. Revenues, and Uncollectible Revenues.

[E] Restated.

Ziply Fiber Northwest, LLC

TEN-YEAR SUMMARY
END-OF-YEAR REVENUES AND LINES

	Revenues ($000's)									
	Total [A]	Local & Special Access Intrastate	Special Access Interstate	Toll & Switched Access	Universal Service [C]	Other Revenues [D]	Residential Lines [B]	Business Lines [B]	UNE NACs [B]	Total
2015	$223,066	$61,448	$37,736	$9,245	$14,251	$100,386	87,221	55,359	16,972	159,552
2016	$219,214	$57,097	$35,420	$8,892	$10,868	$106,937	78,499	51,965	15,656	146,120
2017	$208,499	$51,504	$33,077	$8,846	$9,987	$105,085	69,939	49,666	13,968	133,573
2018	$201,896	$44,762	$34,059	$7,270	$9,108	$106,697	63,476	45,469	12,658	121,603
2019	$197,583	$41,187	$32,190	$6,480	$8,230	$109,496	55,713	41,885	12,658	110,256
2020	$183,340	$35,905	$31,329	$6,274	$7,540	$102,292	35,360	41,815	10,507	87,682
2021	$171,224	$30,469	$27,329	$5,180	$7,635	$100,612	28,479	38,040	6,243	72,762
2022	$169,680	$27,136	$26,763	$5,085	$5,701	$104,994	22,552	32,287	3,675	58,514
2023	$171,258	$25,803	$26,617	$5,064	$5,572	$108,202	17,904	28,840	4,914	51,658
2024	$178,907	$22,838	$25,363	$4,787	$5,683	$120,237	13,687	23,836	1,702	39,225

[A] Total revenues are shown net of uncollectibles and include billing and collection, network access, directories, and miscellaneous revenues. Adjustments have been made for changes in accounting methods regarding collections of OUSF and imputed directory revenue.

[B] The Residential line count is taken directly from the Annual Report Form O, Schedule S-1. The Business line count is taken from the Annual Report Form O and is the total of Business Lines, PBX Trunks, Centrex-Co Lines, and ISDN "B" Channels. The Unbundled Network Elements (UNE) Network Access Channels (NACS) line count is taken directly from the "UNE NACs" of Form O.

[C] Universal Service includes both State and Federal support as reported on the annual Form O.

[D] Other Revenues include Federal USF Collections, Directory Revenue, Carrier Billing & Collections, Non Regulatory Revenues, Misc. Revenues, and Uncollectible Revenues.

Small Telecommunications Utilities [E]

TEN-YEAR SUMMARY
END-OF-YEAR REVENUES AND LINES

	Revenues ($000's)									
	Total [A]	Local & Special Access Intrastate	Special Access Interstate	Toll & Switched Access	Universal Service [C]	Other Revenues [D]	Residential Lines [B]	Business Lines [B]	UNE NACs [B]	Total
2015	$41,404	$7,371	$4,519	$13,341	$14,132	$2,041	13,252	3,852	0	17,104
2016	$39,947	$7,068	$4,528	$14,420	$11,954	$1,977	13,263	3,585	0	16,848
2017	$38,944	$6,925	$3,528	$11,944	$14,392	$2,155	12,254	2,835	0	15,089
2018	$39,234	$6,635	$3,572	$11,997	$15,001	$2,030	11,340	2,739	0	14,079
2019	$39,967	$6,127	$4,739	$9,864	$17,399	$1,837	10,358	2,795	0	13,153
2020	$38,069	$5,690	$4,044	$9,504	$16,237	$2,595	9,427	2,596	0	12,023
2021	$38,458	$5,315	$3,460	$9,975	$16,771	$2,937	8,770	2,546	0	11,316
2022	$38,688	$4,484	$3,287	$11,143	$17,156	$2,619	8,083	2,302	0	10,385
2023	$37,354	$4,377	$2,977	$10,293	$16,857	$2,850	7,099	2,190	0	9,289
2024	$47,160	$3,813	$3,562	$13,681	$23,588	$2,516	6,611	1,960	0	8,571

[A] Total revenues are shown net of uncollectibles and include billing and collection, network access, directories, and miscellaneous revenues. Adjustments have been made for changes in accounting methods regarding collections of OUSF and imputed directory revenue.

[B] The Residential line count is taken directly from the Annual Report Form O, Schedule S-1. The Business line count is taken from the Annual Report Form O and is the total of Business Lines, PBX Trunks, Centrex-Co Lines, and ISDN "B" Channels. The Unbundled Network Elements (UNE) Network Access Channels (NACS) line count is taken directly from the "UNE NACs" of Form O.

[C] Universal Service includes both State and Federal support as reported on the annual Form O.

[D] Other Revenues include Federal USF Collections, Directory Revenue, Carrier Billing & Collections, Non Regulatory Revenues, Misc. Revenues, and Uncollectible Revenues.

[E] Fifteen small telecommunications utilities serve Oregon, as identified in the "Index to Telecommunications Utilities & Cooperatives."

Telecommunications Cooperatives [E]

TEN-YEAR SUMMARY
END-OF-YEAR REVENUES AND LINES

	Revenues ($000's)									
	Total [A]	Local & Special Access Intrastate	Special Access Interstate	Toll & Switched Access	Universal Service [C]	Other Revenues [D]	Residential Lines [B]	Business Lines [B]	UNE NACs [B]	Total
2015	$57,575	$18,100	$8,171	$15,838	$11,782	$3,684	26,849	8,204	0	35,053
2016	$56,877	$17,820	$6,649	$16,681	$12,328	$3,399	26,805	7,986	0	34,791
2017	$59,635	$17,950	$6,439	$21,315	$10,582	$3,350	25,794	8,297	0	34,091
2018	$64,121	$17,162	$6,973	$25,931	$11,371	$2,684	23,136	7,760 [F]	0	30,896
2019	$67,612	$17,085	$8,875	$30,199	$9,197	$2,256	21,580	7,463	0	29,043 [F]
2020	$67,403	$15,299	$10,440	$31,160	$8,159	$2,346	18,958	6,668	0	25,626
2021	$74,744	$15,036	$11,848	$34,009	$7,288	$6,562	17,747	6,341	0	24,088
2022	$75,550	$14,816	$12,252	$35,354	$6,470	$6,658	16,013	5,809	0	21,822
2023	$79,029	$13,299	$13,337	$38,786	$6,969	$6,639	12,713	4,049	0	16,762
2024	$79,070	$12,048	$13,339	$40,390	$6,295	$6,999	10,564	3,281	0	13,845

[A] Total revenues are shown net of uncollectibles and include billing and collection, network access, directories, and miscellaneous revenues. Adjustments have been made for changes in accounting methods regarding collections of OUSF and imputed directory revenue.

[B] The Residential line count is taken directly from the Annual Report Form O, Schedule S-1. The Business line count is taken from the Annual Report Form O and is the total of Business Lines, PBX Trunks, Centrex-Co Lines, and ISDN "B" Channels. The Unbundled Network Elements (UNE) Network Access Channels (NACS) line count is taken directly from the "UNE NACs" of Form O.

[C] Universal Service includes both State and Federal support as reported on the annual Form O.

[D] Other Revenues include Federal USF Collections, Directory Revenue, Carrier Billing & Collections, Non Regulatory Revenues, Misc. Revenues, and Uncollectible Revenues.

[E] Eleven telecommunications cooperatives serve Oregon, as identified in the "Index to Telecommunications Utilities & Cooperatives."

[F] Restated.

Telecommunications Cooperatives [B]

Oregon Operations

Year Ending December 31, 2024

INCOME STATEMENT ($000s)	Beaver Creek Cooperative Tel. Company	Canby Telephone Association	Clear Creek Mutual Tel. Company	Colton Telephone Company	Gervais Telephone Company	Molalla Telephone Company
Operating Revenues						
Local & Special Access	648	682	495	90	123	5,897
Special Access Interstate	1,224	4,292	677	458	405	37
Toll & Switched Access	1,748	9,874	1,397	2,077	1,053	8,886
Federal & State Universal Service Support	219	1,724	238	394	271	444
Directory, Billing & Collection & Other	180	403	89	42	224	12
Total Operating Revenues	4,019	16,975	2,895	3,061	2,076	15,276
Operating Expenses						
Network & General Support Expenses	192	780	217	175	97	871
Central Office Switching Expenses	219	2,150	282	336	113	1,595
Cable & Wire Facilities Expense	789	621	341	199	278	703
Other Plant Specific Expense	0	0	0	0	0	0
Total Plant Specific Expenses	1,200	3,552	840	710	489	3,169
Network Operations & Access Expense	741	1,049	589	97	129	602
Depreciation & Amortization	443	3,347	426	403	307	3,703
Total Plant Non-Specific Expenses	1,184	4,395	1,016	500	437	4,305
Customer Operations	169	775	142	86	98	1,013
General & Administrative Expense	996	3,005	1,003	881	752	2,185
Other Operating Income & Expenses	0	0	0	0	(12)	0
Operating Taxes	98	709	46	106	105	609
Net Jurisdictional Differences	0	0	0	0	0	0
Total Operating Expenses	3,648	12,436	3,048	2,282	1,869	11,281
Net Operating Income	371	4,539	(153)	779	207	3,995
Nonoperating Net Income (Loss)	456	1,321	715	269	265	1,099
Imputations	0	0	0	0	0	0
Reported Net Income	827	5,860	562	1,048	472	5,094

[A]-[E] See Notes on page 86.

Telecommunications Cooperatives [B]

Oregon Operations

Year Ending December 31, 2024

	Beaver Creek Cooperative Tel. Company	Canby Telephone Association	Clear Creek Mutual Tel. Company	Colton Telephone Company	Gervais Telephone Company	Molalla Telephone Company
BALANCE SHEET ($000s)						
Land & Support Assets	5,224	9,669	2,822	1,259	1,006	9,118
Central Office -Switching	375	1,514	59	204	105	384
Central Office -Transmission	3,281	20,940	3,259	1,217	969	12,957
Cable & Wire Facilities	12,597	63,837	8,230	13,231	5,464	55,413
Other Telecommunications Plant	168	139	1	29	182	0
Total Plant in Service	21,644	96,099	14,370	15,940	7,725	77,871
Accumulated Depreciation	(17,588)	(52,378)	(7,512)	(7,296)	(4,220)	(56,782)
Net Telecommunications Plant	4,056	43,722	6,858	8,644	3,506	21,089
Plant Under Construction	38	632	2	1,432	0	707
Non Operating Plant	157	128	0	0	0	0
Current Assets	2,453	11,105	1,652	2,373	1,596	18,091
Other Assets & Other Debits	3,557	5,839	250	1,108	4,418	17,418
Total Assets & Other Debits	10,261	61,426	8,763	13,557	9,519	57,305
Long-Term Debt	2,021	8,636	4,993	3,862	0	6,282
Other Liabilities & Deferred Credits	1,394	4,142	806	1,209	2,370	2,873
Stockholders' Equity	6,846	48,647	2,963	8,486	7,149	48,151
Total Liabilities & Other Credits	10,261	61,426	8,763	13,557	9,519	57,305
STATISTICS						
Plant in Service ($000s)						
Plant in Service Additions	416	5,190	4,533	1,312	733	1,450
Plant in Service Retirements	23	1,617	102	801	49	841
Oregon Universal Service Funds ($000s) [D]	216	712	165	122	86	437
Federal Universal Service Funds ($000s) [E]	1,955	9,440	1,602	2,269	1,167	8,946
Year End Access & Other Lines						
Residential Lines	1,274	351	915	68	163	147
Business Lines	151	437	99	21	109	73
UNE Network Access Channels	0	0	0	0	0	0
Total Lines	1,425	788	1,014	89	272	220

[A]-[E] See Notes on page 86.

Telecommunications Cooperatives [B]

Oregon Operations

Year Ending December 31, 2024

INCOME STATEMENT ($000s)	Monitor Cooperative Tel. Company	Pioneer Telephone Cooperative	St. Paul Cooperative Tel. Association	Scio Mutual Telephone Association	Stayton Cooperative Tel. Company
Operating Revenues					
Local & Special Access	34	2,942	119	30	988
Special Access Interstate	235	3,068	131	750	2,063
Toll & Switched Access	1,253	6,078	789	2,535	4,700
Federal & State Universal Service Support	295	1,237	108	184	1,180
Directory, Billing & Collection & Other	25	5,583	96	24	319
Total Operating Revenues	1,842	18,908	1,243	3,523	9,251
Operating Expenses					
Network & General Support Expenses	51	576	28	203	372
Central Office Switching Expenses	51	1,634	227	252	593
Cable & Wire Facilities Expense	169	1,663	57	36	280
Other Plant Specific Expense	0	0	0	0	0
Total Plant Specific Expenses	272	3,873	311	491	1,245
Network Operations & Access Expense	79	2,451	67	248	872
Depreciation & Amortization	362	1,787	161	1,125	2,679
Total Plant Non-Specific Expenses	441	4,237	228	1,373	3,551
Customer Operations	68	1,711	66	98	306
General & Administrative Expense	606	2,072	338	1,034	2,065
Other Operating Income & Expenses	0	3,066	0	0	0
Operating Taxes	114	365	50	134	532
Net Jurisdictional Differences	0	0	0	0	0
Total Operating Expenses	1,501	15,325	995	3,131	7,700
Net Operating Income	341	3,583	249	392	1,551
Nonoperating Net Income (Loss)	229	346	250	172	2,940
Imputations	0	0	0	0	0
Reported Net Income	570	3,929	499	564	4,492

[A]-[E] See Notes on page 86.

Telecommunications Cooperatives [B]

Oregon Operations

Year Ending December 31, 2024

	Monitor Cooperative Tel. Company	Pioneer Telephone Cooperative	St. Paul Cooperative Tel. Association	Scio Mutual Telephone Association	Stayton Cooperative Tel. Company
BALANCE SHEET ($000s)					
Land & Support Assets	2,239	8,367	513	3,270	8,122
Central Office -Switching	60	1,038	847	500	1,757
Central Office -Transmission	1,157	9,444	395	2,614	13,631
Cable & Wire Facilities	4,188	69,281	4,354	15,354	44,671
Other Telecommunications Plant	31	97	0	29	152
Total Plant in Service	7,674	88,226	6,109	21,767	68,333
Accumulated Depreciation	(4,693)	(76,722)	(3,612)	(14,987)	(45,220)
Net Telecommunications Plant	2,982	11,504	2,497	6,780	23,113
Plant Under Construction	0	16,010	548	1	65
Non Operating Plant	12	0	0	0	0
Current Assets	4,432	20,916	2,007	6,530	19,053
Other Assets & Other Debits	39	4,675	225	4,491	13,169
Total Assets & Other Debits	7,465	53,105	5,276	17,803	55,399
Long-Term Debt	148	0	0	0	0
Other Liabilities & Deferred Credits	508	8,146	225	297	4,212
Stockholders' Equity	6,809	44,959	5,051	17,506	51,187
Total Liabilities & Other Credits	7,465	53,105	5,276	17,803	55,399
STATISTICS					
Plant in Service ($000s)					
Plant in Service Additions	472	2,487	42	576	3,135
Plant in Service Retirements	302	489	0	60	678
Oregon Universal Service Funds ($000s) [D]	281	1,237	108	184	491
Federal Universal Service Funds ($000s) [E]	1,430	5,782	768	2,408	6,000
Year End Access & Other Lines					
Residential Lines	52	6,067	188	58	1,281
Business Lines	22	1,408	154	66	741
UNE Network Access Channels	0	0	0	0	0
Total Lines	74	7,475	342	124	2,022

[A]-[E] See Notes on page 86.

Small Telecommunications Utilities[A]

Oregon Operations

Year Ending December 31, 2024

INCOME STATEMENT ($000s)	Asotin Telephone Company (TDS)	Cascade Utilities, Inc.	Eagle Telephone System, Inc.	Helix Telephone Company	Home Telephone Company (TDS)
Operating Revenues					
Local & Special Access	37	1,632	106	43	175
Special Access Interstate	3	0	499	72	48
Toll & Switched Access	20	2,347	27	125	84
Federal & State Universal Service Support	207	6,912	1,615	1,454	1,572
Directory, Billing & Collection & Other	2	516	3	43	9
Total Operating Revenues	269	11,407	2,249	1,737	1,887
Operating Expenses					
Network & General Support Expenses	4	829	100	15	10
Central Office Switching Expenses	19	764	167	69	103
Cable & Wire Facilities Expense	12	1,463	211	75	99
Other Plant Specific Expense	0	0	0	0	0
Total Plant Specific Expenses	36	3,056	478	159	212
Network Operations & Access Expense	21	932	133	90	78
Depreciation & Amortization	50	2,426	463	38	42
Total Plant Non-Specific Expenses	70	3,358	596	128	120
Customer Operations	7	550	0	43	31
General & Administrative Expense	15	1,501	0	180	166
Other Operating Income & Expenses	(5)	0	(17)	0	0
Operating Taxes	52	1,109	158	315	490
Net Jurisdictional Differences	0	0	0	0	0
Total Operating Expenses	176	9,574	1,214	826	1,019
Net Operating Income	94	1,833	1,036	911	868
Nonoperating Net Income (Loss)	2	5,185	0	(130)	394
Imputations	0	0	0	0	0
Reported Net Income	96	7,018	1,036	781	1,262

[A]-[E] See Notes on page 86.

Small Telecommunications Utilities[A]

Oregon Operations

Year Ending December 31, 2024

	Asotin Telephone Company (TDS)	Cascade Utilities, Inc.	Eagle Telephone System, Inc.	Helix Telephone Company	Home Telephone Company (TDS)
BALANCE SHEET ($000s)					
Land & Support Assets	68	10,344	1,481	1,008	460
Central Office -Switching	0	1,700	325	0	169
Central Office -Transmission	476	8,073	1,758	871	799
Cable & Wire Facilities	1,057	56,836	6,497	2,713	2,977
Other Telecommunications Plant	0	1,205	1,814	1	1
Total Plant in Service	1,601	78,158	11,875	4,592	4,406
Accumulated Depreciation	(1,429)	(41,112)	(13,352)	(3,677)	(3,365)
Net Telecommunications Plant	173	37,046	(1,477)	915	1,041
Plant Under Construction	13	4,018	0	5	377
Non Operating Plant	0	279	7,334	0	0
Current Assets	97	43,052	2,408	610	2,648
Other Assets & Other Debits	8	64,506	1,775	19	622
Total Assets & Other Debits	290	148,901	10,040	1,549	4,688
Long-Term Debt	0	655	0	798	152
Other Liabilities & Deferred Credits	187	15,471	1,794	1,052	920
Stockholders' Equity	103	132,775	8,246	(302)	3,616
Total Liabilities & Other Credits	290	148,901	10,040	1,549	4,688
STATISTICS					
Plant in Service ($000s)					
Plant in Service Additions	0	6,644	581	781	708
Plant in Service Retirements	29	735	0	449	790
Oregon Universal Service Funds ($000s) [D]	26	739	205	130	66
Federal Universal Service Funds ($000s) [E]	700	11,041	1,013	109	79
Year End Access & Other Lines					
Residential Lines	56	2,465	330	95	255
Business Lines	21	738	67	38	130
UNE Network Access Channels	0	0	0	0	0
Total Lines	77	3,203	397	133	385

[A]-[E] See Notes on page 86.

Small Telecommunications Utilities[A]

Oregon Operations

Year Ending December 31, 2024

INCOME STATEMENT ($000s)	Monroe Telephone Company	Nehalem Telecommuni-cations, Inc.	North-State Telephone Company	Oregon Telephone Corporation
Operating Revenues				
Local & Special Access	154	385	111	509
Special Access Interstate	149	36	169	1,044
Toll & Switched Access	25	936	98	1,802
Federal & State Universal Service Support	901	317	1,599	4,460
Directory, Billing & Collection & Other	1,064	116	235	349
Total Operating Revenues	2,293	1,790	2,211	8,164
Operating Expenses				
Network & General Support Expenses	171	134	16	35
Central Office Switching Expenses	444	107	147	429
Cable & Wire Facilities Expense	159	306	182	301
Other Plant Specific Expense	0	0	0	0
Total Plant Specific Expenses	775	546	345	765
Network Operations & Access Expense	20	29	141	519
Depreciation & Amortization	149	258	309	1,258
Total Plant Non-Specific Expenses	169	287	450	1,776
Customer Operations	186	447	64	216
General & Administrative Expense	566	731	283	995
Other Operating Income & Expenses	0	26	0	0
Operating Taxes	201	43	265	1,606
Net Jurisdictional Differences	0	0	0	0
Total Operating Expenses	1,897	2,081	1,407	5,358
Net Operating Income	396	(290)	804	2,806
Nonoperating Net Income (Loss)	(133)	(14)	(98)	523
Imputations	0	0	0	0
Reported Net Income	263	(304)	707	3,329

[A]-[E] See Notes on page 86.

Small Telecommunications Utilities[A]

Oregon Operations

Year Ending December 31, 2024

	Monroe Telephone Company	Nehalem Telecommuni-cations, Inc.	North-State Telephone Company	Oregon Telephone Corporation
BALANCE SHEET ($000s)				
Land & Support Assets	1,752	1,371	322	4,253
Central Office -Switching	770	344	0	1,577
Central Office -Transmission	413	1,315	1,190	3,521
Cable & Wire Facilities	4,409	5,715	10,427	24,168
Other Telecommunications Plant	3	3,656	234	6
Total Plant in Service	7,346	12,401	12,173	33,525
Accumulated Depreciation	(5,851)	(10,540)	(7,318)	(21,897)
Net Telecommunications Plant	1,494	1,861	4,855	11,628
Plant Under Construction	31	7	73	3,273
Non Operating Plant	0	0	150	649
Current Assets	1,972	647	1,661	16,478
Other Assets & Other Debits	3,370	181	6,518	25,785
Total Assets & Other Debits	6,867	2,696	13,258	57,811
Long-Term Debt	613	0	1,486	6,053
Other Liabilities & Deferred Credits	2,821	345	2,691	14,312
Stockholders' Equity	3,433	2,351	9,081	37,446
Total Liabilities & Other Credits	6,867	2,696	13,258	57,811
STATISTICS				
Plant in Service ($000s)				
Plant in Service Additions	413	545	0	364
Plant in Service Retirements	128	2,914	521	501
Oregon Universal Service Funds ($000s) [D]	198	318	97	263
Federal Universal Service Funds ($000s) [E]	697	517	71	11,540
Year End Access & Other Lines				
Residential Lines	521	677	244	908
Business Lines	96	210	50	202
UNE Network Access Channels	0	0	0	0
Total Lines	617	887	294	1,110

[A]-[E] See Notes on page 86.

Small Telecommunications Utilities[A]

Oregon Operations

Year Ending December 31, 2024

INCOME STATEMENT ($000s)	Oregon-Idaho Utilities, Inc.	Peoples Telephone Company	Pine Telephone System, Inc.	Roome Telecommuni-cations Inc.	Trans-Cascades Telephone Company
Operating Revenues					
Local & Special Access	212	149	193	34	74
Special Access Interstate	885	363	271	22	0
Toll & Switched Access	1,275	1,574	903	13	4,453
Federal & State Universal Service Support	775	484	2,830	334	129
Directory, Billing & Collection & Other	51	37	79	0	13
Total Operating Revenues	3,197	2,607	4,276	403	4,670
Operating Expenses					
Network & General Support Expenses	269	89	30	21	9
Central Office Switching Expenses	282	128	492	22	18
Cable & Wire Facilities Expense	590	76	90	14	10
Other Plant Specific Expense	0	0	0	0	0
Total Plant Specific Expenses	1,141	293	613	57	37
Network Operations & Access Expense	410	177	312	42	21
Depreciation & Amortization	805	742	1,317	27	53
Total Plant Non-Specific Expenses	1,216	919	1,629	69	74
Customer Operations	118	67	134	26	19
General & Administrative Expense	882	657	457	150	156
Other Operating Income & Expenses	0	0	0	0	(0)
Operating Taxes	(18)	316	472	29	52
Net Jurisdictional Differences	0	0	0	0	0
Total Operating Expenses	3,339	2,252	3,304	329	339
Net Operating Income	(141)	355	972	73	4,331
Nonoperating Net Income (Loss)	(131)	349	(432)	(59)	239
Imputations	0	0	0	0	0
Reported Net Income	(272)	704	540	15	4,570

[A]-[E] See Notes on page 86.

Small Telecommunications Utilities[A]

Oregon Operations

Year Ending December 31, 2024

	Oregon-Idaho Utilities, Inc.	Peoples Telephone Company	Pine Telephone System, Inc.	Roome Telecommuni-cations Inc.	Trans-Cascades Telephone Company
BALANCE SHEET ($000s)					
Land & Support Assets	2,712	171	3,222	889	365
Central Office -Switching	780	149	0	205	13
Central Office -Transmission	2,782	2,182	4,639	292	432
Cable & Wire Facilities	14,290	13,686	29,530	1,926	1,616
Other Telecommunications Plant	130	0	63	4	39
Total Plant in Service	20,694	16,189	37,455	3,316	2,465
Accumulated Depreciation	(17,217)	(9,500)	(31,892)	(2,923)	(1,816)
Net Telecommunications Plant	3,477	6,689	5,562	394	649
Plant Under Construction	7	25	959	0	1,566
Non Operating Plant	161	0	427	0	0
Current Assets	1,707	6,549	5,143	318	3,654
Other Assets & Other Debits	5	69	663	11	3,333
Total Assets & Other Debits	5,357	13,332	12,753	723	9,202
Long-Term Debt	0	0	4,337	823	286
Other Liabilities & Deferred Credits	(114)	1,106	3,626	364	129
Stockholders' Equity	5,471	12,226	4,790	(464)	8,786
Total Liabilities & Other Credits	5,357	13,332	12,753	723	9,202
STATISTICS					
Plant in Service ($000s)					
Plant in Service Additions	1,333	718	309	46	280
Plant in Service Retirements	71	82	1,202	0	41
Oregon Universal Service Funds ($000s) [D]	248	181	656	54	129
Federal Universal Service Funds ($000s) [E]	1,700	2,644	626	757	30
Year End Access & Other Lines					
Residential Lines	276	260	384	54	86
Business Lines	83	82	122	88	33
UNE Network Access Channels	0	0	0	0	0
Total Lines	359	342	506	142	119

[A]-[E] See Notes on page 86.

Large Telecommunications Utilities[C]

Oregon Operations

Year Ending December 31, 2024

INCOME STATEMENT ($000s)	CenturyTel of Eastern Oregon, Inc.	CenturyTel of Oregon, Inc.	Qwest Corp. dba CenturyLink QC	United Telephone Co. of the Northwest	Ziply Fiber of Oregon LLC	Ziply Fiber Northwest, LLC
Operating Revenues						
Local & Special Access	3,840	2,752	62,311	6,869	1,294	22,838
Special Access Interstate	7,055	6,343	227,436	16,064	349	25,363
Toll & Switched Access	106	127	5,611	616	88	4,787
Federal & State Universal Service Support	2,357	1,400	9,787	2,911	768	5,683
Directory, Billing & Collection & Other	1,853	1,789	63,666	3,276	2,427	120,237
Total Operating Revenues	15,211	12,412	368,812	29,736	4,925	178,907
Operating Expenses						
Network & General Support Expenses	765	467	7,833	1,025	122	4,447
Central Office Switching Expenses	2,067	1,159	8,521	2,149	5	180
Cable & Wire Facilities Expense	4,392	2,513	39,128	4,463	274	9,943
Other Plant Specific Expense	0	0	7,413	0	0	0
Total Plant Specific Expenses	7,225	4,139	62,896	7,638	401	14,569
Network Operations & Access Expense	2,333	938	19,997	1,649	531	19,290
Depreciation & Amortization	2,278	1,686	46,552	3,739	1,243	31,626
Total Plant Non-Specific Expenses	4,611	2,624	66,549	5,388	1,774	50,916
Customer Operations	1,232	969	26,971	1,665	592	21,492
General & Administrative Expense	3,366	2,184	39,125	3,247	616	22,378
Other Operating Income & Expenses	0	0	0	1	368	2,288
Operating Taxes	(139)	637	55,316	3,064	0	9,301
Net Jurisdictional Differences	0	0	0	0	0	0
Total Operating Expenses	16,295	10,553	250,857	21,004	3,751	120,944
Net Operating Income	(1,084)	1,859	117,955	8,732	1,174	57,964
Nonoperating Net Income (Loss)	(251)	438	(1,930)	115	(225)	(11,046)
Imputations	0	0	0	0	0	0
Reported Net Income	(1,335)	2,298	116,025	8,847	949	46,917

[A]-[E] See Notes on page 86.

Large Telecommunications Utilities[C]

Oregon Operations

Year Ending December 31, 2024

	CenturyTel of Eastern Oregon, Inc.	CenturyTel of Oregon, Inc.	Qwest Corp. dba CenturyLink QC	United Telephone Co. of the Northwest	Ziply Fiber of Oregon LLC	Ziply Fiber Northwest, LLC
BALANCE SHEET ($000s)						
Land & Support Assets	9,850	5,766	195,328	17,830	2,566	94,843
Central Office -Switching	20,819	22,304	58,043	5,922	430	13,491
Central Office -Transmission	58,843	35,393	311,695	30,901	2,805	51,192
Cable & Wire Facilities	68,856	34,008	567,527	72,776	12,470	284,258
Other Telecommunications Plant	979	3	3,823	320	76	1,459
Total Plant in Service	159,346	97,474	1,136,415	127,749	18,347	445,243
Accumulated Depreciation	(142,685)	(86,200)	(612,279)	(94,100)	(5,400)	(152,178)
Net Telecommunications Plant	16,661	11,274	524,135	33,649	12,947	293,065
Plant Under Construction	0	0	0	0	4,372	86,592
Non Operating Plant	0	0	0	0	0	0
Current Assets	9	7	93	9	(1,560)	39,344
Other Assets & Other Debits	0	0	0	0	502	10,772
Total Assets & Other Debits	16,669	11,281	524,228	33,658	16,261	429,774
Long-Term Debt	0	0	0	0	0	0
Other Liabilities & Deferred Credits	7,777	2,499	146,089	3,591	839	22,607
Stockholders' Equity	(37,793)	2,931	1,037,581	52,823	15,421	407,167
Total Liabilities & Other Credits	(30,016)	5,430	N/A	N/A	16,261	429,774
STATISTICS						
Plant in Service ($000s)						
Plant in Service Additions	1,523	1,034	49,335	2,076	11,291	183,067
Plant in Service Retirements	77	147	4,220	93	5	497
Oregon Universal Service Funds ($000s) [D]		2,719	8,158	2,120	767	4,932
Federal Universal Service Funds ($000s) [E]			4,142		363	508
Year End Access & Other Lines						
Residential Lines	3,852	3,581	54,696	4,863	1,612	13,687
Business Lines	2,631	1,418	60,574	3,892	391	23,836
UNE Network Access Channels	0	0	22,294	591	0	1,702
Total Lines	6,483	4,999	137,564	9,346	2,003	39,225

[A]-[E] See Notes on page 86.

Telecommunications Utilities and Cooperatives

Oregon Operations

Year Ending December 31, 2024

INCOME STATEMENT ($000s)	**Total of Telecom. Cooperatives** [B]	**Total of Small Telecommunications Utilities** [A]	**Total of Large Telecommunications Utilities & Affiliates** [C]	**Total ILECs Serving Oregon**
Operating Revenues				
Local & Special Access	12,048	3,813	99,905	115,765
Special Access Interstate	13,339	3,562	282,610	299,510
Toll & Switched Access	40,390	13,681	11,335	65,406
Federal & State Universal Service Support	6,295	23,588	22,906	52,789
Directory, Billing & Collection & Other	6,999	2,516	193,247	202,762
Total Operating Revenues	79,070	47,160	610,003	736,233
Operating Expenses				
Network & General Support Expenses	3,563	1,731	14,659	19,953
Central Office Switching Expenses	7,453	3,190	14,082	24,724
Cable & Wire Facilities Expense	5,136	3,590	60,713	69,439
Other Plant Specific Expense	0	0	7,413	7,413
Total Plant Specific Expenses	16,151	8,511	96,867	121,530
Network Operations & Access Expense	6,925	2,925	44,739	54,589
Depreciation & Amortization	14,743	7,937	87,124	109,803
Total Plant Non-Specific Expenses	21,668	10,862	131,863	164,392
Customer Operations	4,535	1,908	52,920	59,362
General & Administrative Expense	14,937	6,738	70,917	92,593
Other Operating Income & Expenses	3,054	4	2,656	5,715
Operating Taxes	2,869	5,089	68,180	76,138
Net Jurisdictional Differences	0	0	0	0
Total Operating Expenses	63,215	33,113	423,403	519,731
Net Operating Income	15,855	14,047	186,600	216,502
Nonoperating Net Income (Loss)	8,061	5,696	(12,899)	859
Imputations	0	0	0	0
Reported Net Income	23,916	19,743	173,701	217,361

[A]-[E] See Notes on page 86.

Telecommunications Utilities and Cooperatives

Oregon Operations

Year Ending December 31, 2024

	Total of Telecom. Cooperatives	Total of Small Telecommunications Utilities	Total of Large Telecommunications Utilities & Affiliates	Total ILECs Serving Oregon
BALANCE SHEET ($000s)	[B]	[A]	[C]	
Land & Support Assets	51,607	28,418	326,183	406,207
Central Office -Switching	6,842	6,033	121,009	133,883
Central Office -Transmission	69,863	28,742	490,829	589,434
Cable & Wire Facilities	296,620	175,848	1,039,894	1,512,361
Other Telecommunications Plant	828	7,155	6,659	14,642
Total Plant in Service	425,759	246,195	1,984,574	2,656,528
Accumulated Depreciation	(291,009)	(171,888)	(1,092,843)	(1,555,741)
Net Telecommunications Plant	134,750	74,307	891,730	1,100,787
Plant Under Construction	19,436	10,351	90,964	120,751
Non Operating Plant	297	8,999	0	9,296
Current Assets	90,207	86,944	37,902	215,053
Other Assets & Other Debits	55,188	106,867	11,274	173,330
Total Assets & Other Debits	299,878	287,468	1,031,871	1,619,217
Long-Term Debt	25,942	15,204	N/A	N/A
Other Liabilities & Deferred Credits	26,182	44,705	183,401	254,288
Stockholders' Equity	247,754	227,560	1,478,130	1,953,444
Total Liabilities & Other Credits	299,878	287,468	N/A	N/A
STATISTICS				
Plant in Service ($000s)				
Plant in Service Additions	20,347	12,723	248,326	281,396
Plant in Service Retirements	4,961	7,465	5,038	17,464
Oregon Universal Service Funds ($000s) [D]	4,039	3,310	18,696	26,045
Federal Universal Service Funds ($000s) [E]	41,767	31,524	5,013	78,304
Year End Access & Other Lines				
Residential Lines	10,564	6,611	82,291	99,466
Business Lines	3,281	1,960	92,742	97,983
UNE Network Access Channels	0	0	24,587	24,587
Total Lines	13,845	8,571	199,620	222,036

[A]-[E] See Notes on page 86.

Telecommunications Utilities and Cooperatives

Notes to Financial and Statistical Data

[A] The statistics of the small utilities are heavily weighted by Cascade Utilities, which serves 37 percent of Oregon's small telecommunications utility customers excluding Ziply Fiber of Oregon, LLC. For this report, Ziply Fiber of Oregon, LLC is included with its affiliate in the Large Telecommunications Utilities and Affiliates category.

[B] The statistics of the cooperatives are heavily weighted by Pioneer Telephone Cooperative, which serves 52 percent of Oregon's telecommunications cooperatives members.

[C] For this report, Ziply Fiber of Oregon, LLC is included with its affiliate in the Large Telecommunications Utilites and Affiliates category.

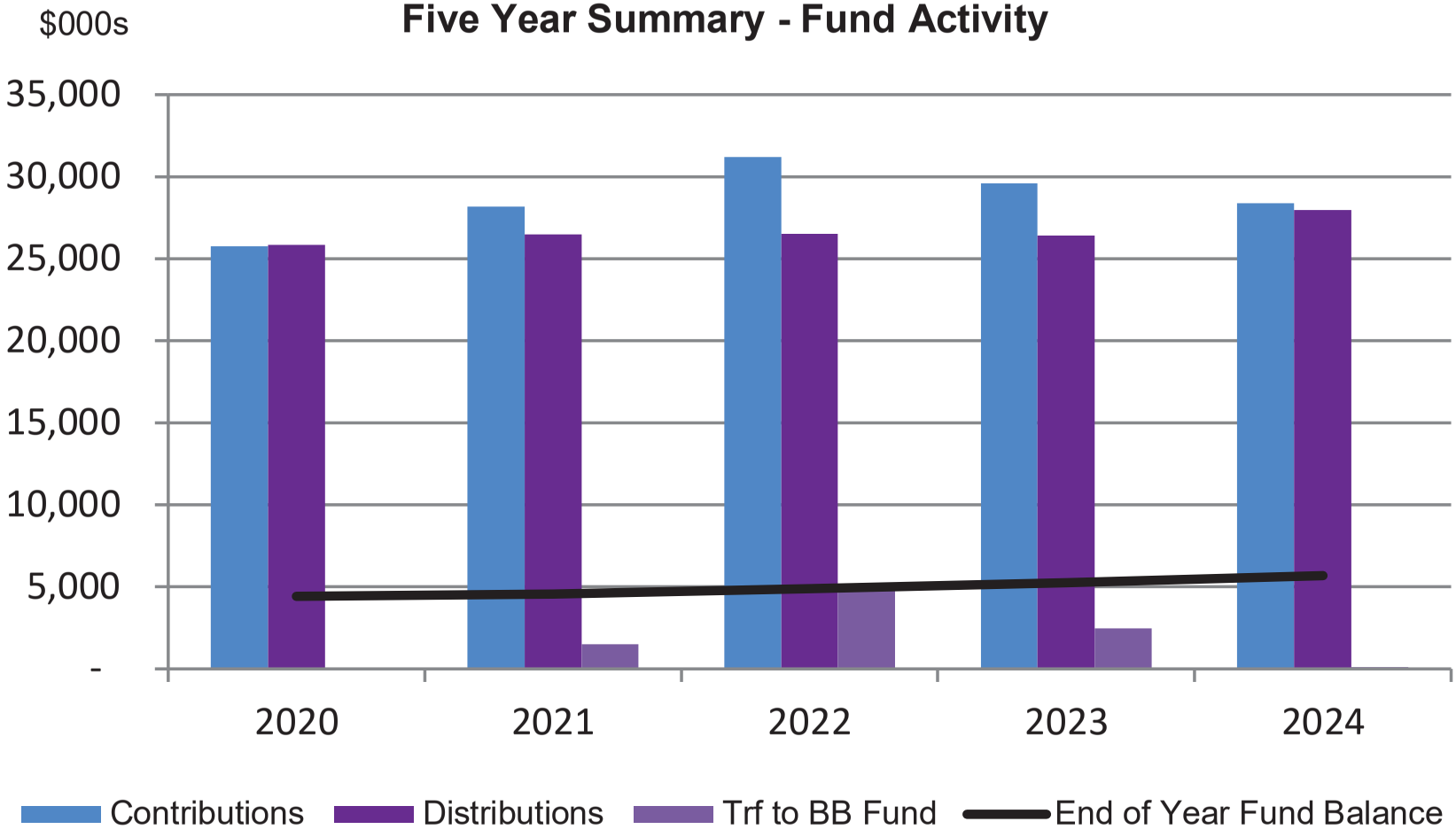
[D] Oregon Universal Service Fund amounts are as recorded in the Oregon Public Utility Commission's OUSF system.

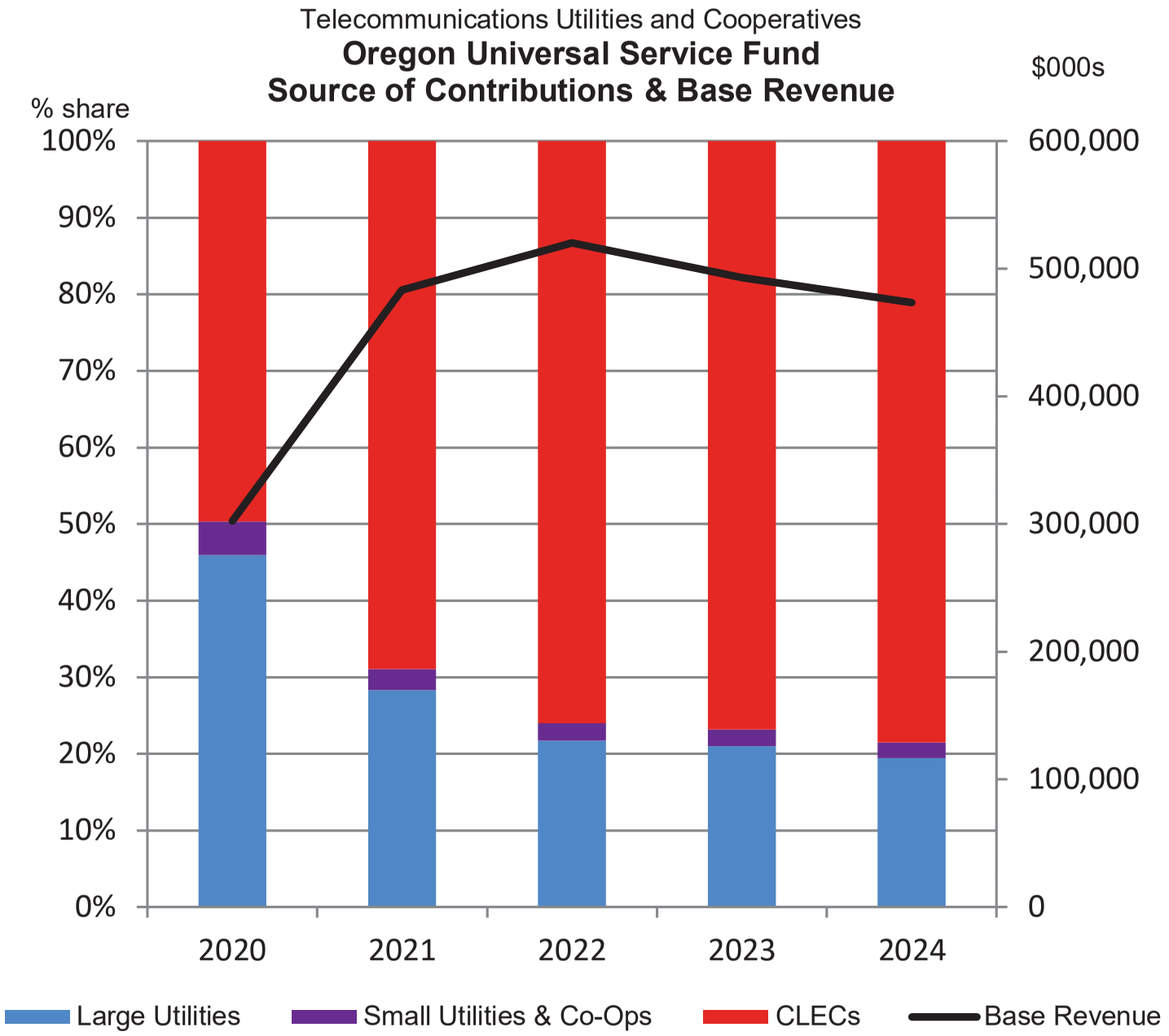
[E] Federal Universal Service Fund amounts are as recorded in the USAC system.

Telecommunications Utilities and Cooperatives

Oregon Universal Service Fund

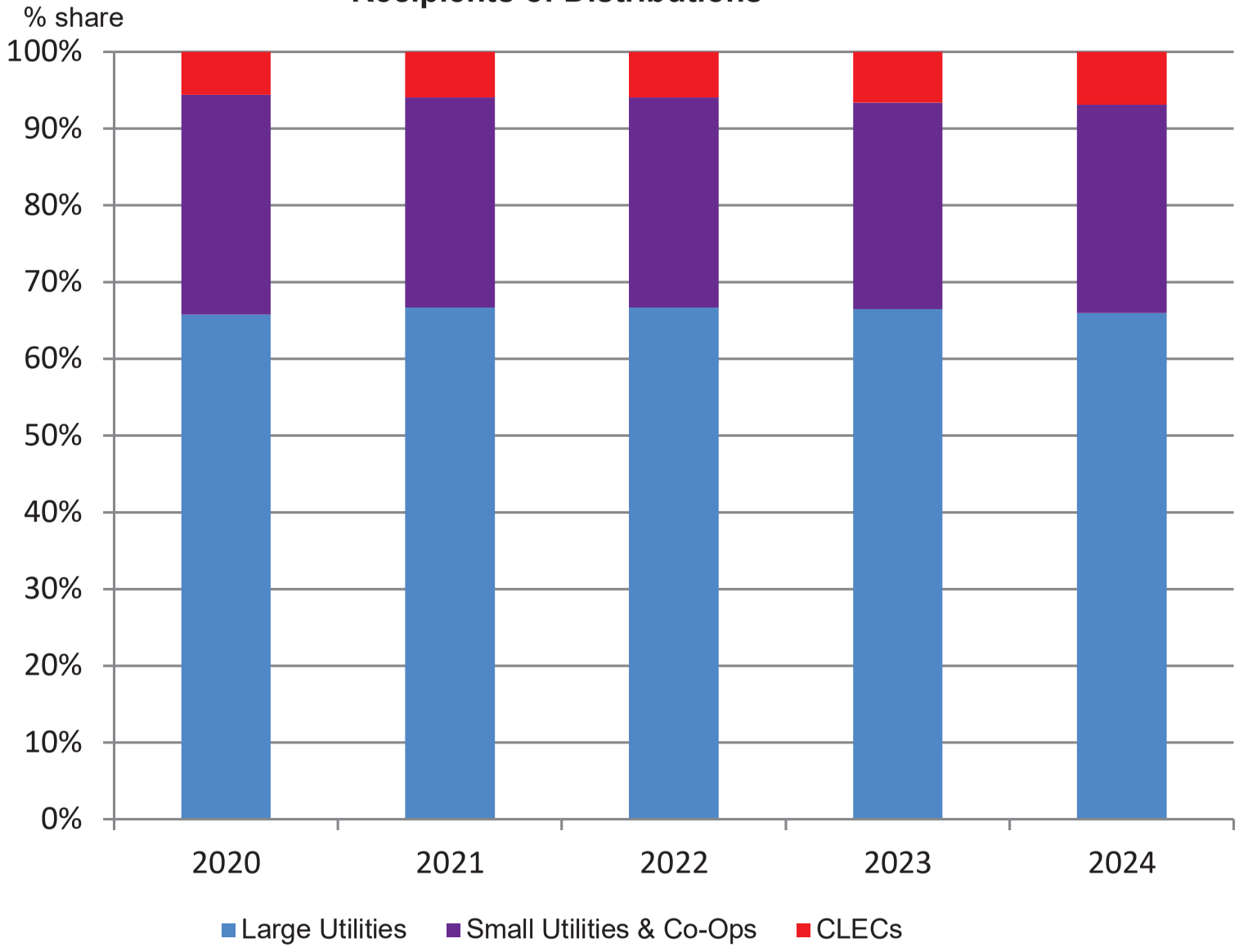
Five Year Summary - Fund Activity




Telecommunications Utilities and Cooperatives
Oregon Universal Service Fund
Source of Contributions & Base Revenue
% share
$000s
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
600,000
500,000
400,000
300,000
200,000
100,000
0
2020
2021
2022
2023
2024
Large Utilities
Small Utilities & Co-Ops
CLECs
Base Revenue

Telecommunications Utilities and Cooperatives

Oregon Universal Service Fund
Recipients of Distributions



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Water

Foreword to Water Utilities

In general, only investor-owned water utilities and some water associations (when regulation is requested by 20 percent of membership) are regulated by the Oregon Public Utility Commission (OPUC). The Commission regulates water rates if: 1) the utility serves 500 or more customers; 2) the utility has an average monthly residential rate exceeding $42 for unmetered systems or $45 for metered systems and 20 percent or more of its customers petition the Commission requesting regulation of rates; or 3) the utility requests to be regulated.

During 2024, there were approximately 85 water utilities subject to OPUC jurisdiction, however, only rate-regulated water utilities are required to file annual reports with the Commission.

For accounting purposes, water utilities are classified as A, B, and C, according to the level of water operating revenues.

Class A water utilities consistently have annual water operating revenues of $1,000,000 or more. There were five Class A water utilities in 2024, for a list of the companies, see the index on the following pages.

Class B water utilities consistently have annual water operating revenues between $200,000 and $999,999. There were six Class B water utilities in 2024, for a list of the companies, see the index on the following pages.

Class C water utilities consistently have annual water operating revenues of less than $200,000. There were twenty-two Class C water utilities in 2024, for a list of the companies, see the index on the following pages.

Index to Water Utilities

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Investor-Owned

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Financial Data & Sales Statistics 93
- Avion Water Company, Inc.
- Crooked River Ranch Water Company
- Oregon Water Utilities - Cline Butte Inc.
- Roats Water System Inc.
- Sunriver Water LLC

Class B Water Utilities
Financial Data & Sales Statistics 95
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- Illahe Estates Water System LLC
- Oregon Water Utilities – Mountain Lakes Inc.
- Salmon Valley Water Company, Inc.
- Willamette Water Company

Class C Water Utilities
Financial Data & Sales Statistics 97
- Agate Water Company
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- Aspen Lakes Utility Company LLC
- Bethel Park Water
- Clearwater Source LLC
- DWF Round Lake Park & Utilities LLC
- Helton Water Company LLC

Hillview Water Service LLC
Lakeshore Water Company LLC
Metolius Meadows Property Owners Association
North Hill Water Corporation
Old Sheep Ranch Water Association
Seavey Loop Water Holdings, LLC
Seventh Mountain Golf Village Water Company
Shadow Wood Water Service LLC
South Coast Water District, Inc.
South Hills Water System, Inc.
Storlie Water Company
Tierra Del Mar Water Company
Westwood Water System LLC
Wilderness Canyon Water LLC

Rate Regulated Water Utilities - Class A

Financial Data and Sales Statistics

Year Ending December 31, 2024

	Avion Water Company, Inc.	Crooked River Ranch Water Company	Oregon Water Utilities Cline Butte Inc.	Roats Water System, Inc.	Sunriver Water LLC
ASSETS & OTHER DEBITS					
Utility Plant	$92,097,645	$11,134,165	$12,293,569	$8,669,855	$15,423,467
Less: Depreciation & Amortization Reserve	27,260,771	4,570,753	5,076,898	3,685,232	4,899,073
Other Property & Investments	1,734,981	382,881	1,801,736	128,576	524,281
Materials and Supplies	754,843	0	5,064	77,940	63,453
Other Current & Accrued Assets	4,061,373	0	177,819	1,587,788	971,615
Deferred Debits	0	0	0	0	0
Total Assets & Other Debits	$71,388,070	$6,946,293	$9,201,290	$6,778,927	$12,083,743
LIABILITIES & OTHER CREDITS					
Capital/Common Stock	$3,143,291	$0	$0	$1,107,603	$7,691,923
Retained Earnings	14,922,188	2,764,190	714,095	2,036,409	4,280
Long-Term Debt	10,265,530	4,178,889	0	1,241,082	0
Customer Deposits	1,500	2,775	0	11,151	0
Other Current & Accrued Liabilities	856,279	439	7,943,377	185,172	374,695
Advances for Construction	0	0	0	0	0
Other Deferred Credits	0	0	0	0	129,007
Contributions in Aid of Construction	41,357,587	0	779,559	1,801,148	3,384,744
Accumulated Deferred Income Taxes	841,694	0	(235,741)	396,362	499,094
Total Liabilities & Other Credits	$71,388,070	$6,946,293	$9,201,290	$6,778,927	$12,083,743
AVERAGE NUMBER OF CUSTOMERS					
Flat Rate	0	0	0	0	40
Metered - Residential	15,085	1,639	1,597	2,451	4,688
Metered - Commercial	368	54	26	548	137
Irrigation (including golf courses)	859	0	135	570	113
Fire Protection	0	0	0	3,089	0
Other	0	0	1	277	0
Total Customers	16,312	1,693	1,759	6,935	4,978

Rate Regulated Water Utilities - Class A

Financial Data and Sales Statistics

Year Ending December 31, 2024

	Avion Water Company, Inc.	Crooked River Ranch Water Company	Oregon Water Utilities Cline Butte Inc.	Roats Water System, Inc.	Sunriver Water LLC
OPERATING REVENUES					
Flat Rate	$0	$0	$0	$0	$16,150
Metered - Residential	9,011,278	1,226,635	843,582	1,427,084	1,718,445
Metered - Commercial	1,415,221	65,662	77,549	423,141	229,117
Irrigation (including golf courses)	669,645	0	318,965	279,221	454,592
Fire Protection	95,557	0	0	32,996	14,627
Other Sales of Water	77,341	0	5,475	227,251	0
Other Operating Revenue	1,040,851	69,521	57,409	67,217	117,492
Total Operating Revenues	$12,309,893	$1,361,818	$1,302,980	$2,456,910	$2,550,423
OPERATING EXPENSES					
Purchased Water	$416,574	$0	$0	$122,744	$0
Purchased Power	1,323,389	118,873	163,150	208,918	98,325
Water Treatment	51,215	5,456	5,700	6,487	0
Supplies and Expenses	1,634,156	218,345	174,339	520,776	363,470
Repairs of Plant	294,638	27,998	25,621	77,428	28,977
Administrative & General	4,831,068	579,874	493,967	1,028,753	1,061,035
Total Operating Expenses	$8,551,040	$950,546	$862,777	$1,965,106	$1,551,807
OTHER REVENUE DEDUCTIONS					
Depreciation & Amortization	$906,433	$372,022	$332,708	$239,084	$420,163
Operating Income Taxes	305,982	0	483	27,481	126,975
Other Operating Taxes	1,297,091	34,278	105,460	113,205	153,791
Uncollectible Revenue/Bad Debt Expense	7,501	0	616	1,384	(10,672)
Total Revenue Deductions	$2,517,007	$406,300	$439,267	$381,154	$690,257
Total Expenses and Deductions	$11,068,047	$1,356,846	$1,302,044	$2,346,260	$2,242,064
Other Income	$8,484	$0	$0	$38,150	$0
Interest on Long-Term Debt	0	0	0	0	0
Other Interest Charges	399,316	0	0	82,046	0
Other Income Deductions	(60,271)	0	(483)	12,373	(14,465)
NET OPERATING INCOME (or Loss)	$911,285	$4,972	$1,419	$54,381	$322,825

Rate Regulated Water Utilities - Class B

Financial Data and Sales Statistics

Year Ending December 31, 2024

	Charbonneau Water Company, LLC [B]	Government Camp Water Company	Illahe Estates Water System LLC [A]	Oregon Water Utilities Mountain Lakes Inc.	Salmon Valley Water Company, Inc.	Willamette Water Company
ASSETS & OTHER DEBITS						
Utility Plant	$2,174,742	$908,026	$0	$7,244,527	$5,059,844	$1,546,514
Less: Depreciation & Amortization Reserve	1,374,538	662,596	0	3,728,312	1,173,207	1,071,915
Other Property & Investments	6,775	28,614	0	1,762,006	407,532	42,573
Materials and Supplies	0	12,873	0	1,371	118	80
Other Current & Accrued Assets	862	4,054	0	797,225	420,399	14,791
Deferred Debits	0	178,861	0	0	0	0
Total Assets & Other Debits	$807,841	$469,832	$0	$6,076,817	$4,714,686	$532,042
LIABILITIES & OTHER CREDITS						
Capital/Common Stock	$200,000	$100	$0	$0	$3,574,845	$0
Retained Earnings	517,350	87,318	0	268,533	(850,110)	499,830
Long-Term Debt	0	182,330	0	0	0	(1,046,437)
Customer Deposits	0	0	0	0	0	0
Other Current & Accrued Liabilities	90,491	0	0	5,735,652	1,816,373	4,292
Advances for Construction	0	0	0	0	0	1,074,357
Other Deferred Credits	0	200,083	0	0	0	0
Contributions in Aid of Construction	0	0	0	185,453	88,539	0
Accumulated Deferred Income Taxes	0	0	0	(112,821)	85,039	0
Total Liabilities & Other Credits	$807,841	$469,832	$0	$6,076,817	$4,714,686	$532,042
AVERAGE NUMBER OF CUSTOMERS						
Flat Rate	0	244	0	0	0	0
Metered - Residential	0	74	0	733	901	0
Metered - Commercial	0	87	0	25	62	99
Irrigation (including golf courses)	16	0	0	48	0	64
Fire Protection	0	0	0	0	0	0
Other	0	0	0	0	0	9
Total Customers	16	405	0	806	963	172

[A] Company did not file an annual report in time to be included.

[B] Year ending 03/31/24 report is used, the company's fiscal year ends on 3/31 of each year and the next report is not anticipated to be filed before the preparation of this publication.

Rate Regulated Water Utilities - Class B

Financial Data and Sales Statistics

Year Ending December 31, 2024

	Charbonneau Water Company, LLC [B]	Government Camp Water Company	Illahe Estates Water System LLC [A]	Oregon Water Utilities Mountain Lakes, Inc.	Salmon Valley Water Company, Inc.	Willamette Water Company
OPERATING REVENUES						
Flat Rate	$0	$88,109	$0	$0	$0	$0
Metered - Residential	0	29,438	0	464,995	790,365	94,356
Metered - Commercial	0	119,164	0	101,752	164,585	195,138
Irrigation (including golf courses)	369,553	0	0	155,507	0	0
Fire Protection	0	1,202	0	0	0	4,011
Other Sales of Water	0	0	0	0	0	225
Other Operating Revenue	0	4,524	0	24,027	2,096	315
Total Operating Revenues	$369,553	$242,437	$0	$746,281	$957,045	$294,046
OPERATING EXPENSES						
Purchased Water	$0	$0	$0	$0	$0	$138,182
Purchased Power	57,063	269	0	98,781	36,662	0
Water Treatment	538	1,501	0	4,950	5,547	1,396
Supplies and Expenses	54,243	30,161	0	53,276	138,461	13,294
Repairs of Plant	15,659	0	0	8,883	16,342	3,316
Administrative & General	142,564	149,399	0	309,954	429,097	131,414
Total Operating Expenses	$270,067	$181,330	$0	$475,844	$626,109	$287,602
OTHER REVENUE DEDUCTIONS						
Depreciation & Amortization	$53,957	$25,498	$0	$168,584	$153,558	$48,702
Operating Income Taxes	300	0	0	18,068	39,126	150
Other Operating Taxes	27,005	13,849	0	25,822	46,212	0
Uncollectible Revenue/Bad Debt Expense	0	0	0	1,063	15,000	0
Total Revenue Deductions	$81,262	$39,347	$0	$213,537	$253,895	$48,852
Total Expenses and Deductions	$351,329	$220,677	$0	$689,381	$880,005	$336,454
Other Income	$0	$153	$0	$0	$0	$0
Interest on Long-Term Debt	0	0	0	0	0	0
Other Interest Charges	0	14,625	0	0	0	56,706
Other Income Deductions	0	0	0	(18,068)	(19,396)	0
NET OPERATING INCOME (or Loss)	$18,224	$7,287	$0	$74,968	$96,437	($99,114)

[A] Company did not file an annual report in time to be included.

[B] Year ending 03/31/24 report is used, the company's fiscal year ends on 3/31 of each year and the next report is not anticipated to be filed before the preparation of this publication.

Rate Regulated Water Utilities - Class C

Financial Data and Sales Statistics

Year Ending December 31, 2024

	Agate Water Company [A]	Air Acres Water System	Angler's Cove Shady Cove Heights Water Company	Aspen Lakes Utility Company LLC	Bethel Park Water [A]
ASSETS & OTHER DEBITS					
Utility Plant	$0	$37,677	$114,635	$51,431	$0
Less: Depreciation & Amortization Reserve	0	44,262	76,081	51,431	0
Other Property & Investments	0	42,607	21,994	3,546	0
Materials and Supplies	0	0	230	0	0
Other Current & Accrued Assets	0	(1,749)	31,295	268,953	0
Deferred Debits	0	0	0	0	0
Total Assets & Other Debits	$0	$34,273	$92,073	$272,498	$0
LIABILITIES & OTHER CREDITS					
Capital/Common Stock	$0	$0	$74,635	$131,313	$0
Retained Earnings	0	34,200	17,438	11,051	0
Long-Term Debt	0	73	0	0	0
Customer Deposits	0	0	0	0	0
Other Current & Accrued Liabilities	0	0	0	130,134	0
Advances for Construction	0	0	0	0	0
Other Deferred Credits	0	0	0	0	0
Contributions in Aid of Construction	0	0	0	0	0
Accumulated Deferred Income Taxes	0	0	0	0	0
Total Liabilities & Other Credits	$0	$34,273	$92,073	$272,498	$0
AVERAGE NUMBER OF CUSTOMERS					
Flat Rate	0	0	0	2	0
Metered - Residential	0	0	0	95	0
Metered - Commercial	0	14	0	2	0
Irrigation (including golf courses)	0	0	0	92	0
Fire Protection	0	0	0	0	0
Other	0	0	0	0	0
Total Customers	0	14	0	191	0

[A] Company did not file an annual report in time to be included.

Rate Regulated Water Utilities - Class C

Financial Data and Sales Statistics

Year Ending December 31, 2024

	Agate Water Company [A]	Air Acres Water System	Angler's Cove Shady Cove Heights Water Company	Aspen Lakes Utility Company LLC	Bethel Park Water [A]
OPERATING REVENUES					
Flat Rate	$0	$0	$0	$365	$0
Metered - Residential	0	23,769	35,827	21,426	0
Metered - Commercial	0	0	0	3,576	0
Irrigation (including golf courses)	0	0	0	91,248	0
Fire Protection	0	0	0	0	0
Other Sales of Water	0	0	0	0	0
Other Operating Revenue	0	0	969	25,786	0
Total Operating Revenues	$0	$23,769	$36,796	$142,400	$0
OPERATING EXPENSES					
Purchased Water	$0	$0	$0	$0	$0
Purchased Power	0	1,711	3,263	46,157	0
Water Treatment	0	3,000	4,491	9,784	0
Supplies and Expenses	0	12,931	2,537	32,150	0
Repairs of Plant	0	4,687	853	4,383	0
Administrative & General	0	9,260	18,060	21,424	0
Total Operating Expenses	$0	$31,590	$29,204	$113,897	$0
OTHER REVENUE DEDUCTIONS					
Depreciation & Amortization	$0	$8,950	$3,398	$0	$0
Operating Income Taxes	0	1,988	0	150	0
Other Operating Taxes	0	198	490	1,604	0
Uncollectible Revenue/Bad Debt Expense	0	0	0	0	0
Total Revenue Deductions	$0	$11,136	$3,888	$1,754	$0
Total Expenses and Deductions	$0	$42,726	$33,092	$115,651	$0
Other Income	$0	$0	$0	$0	$0
Interest on Long-Term Debt	0	0	0	0	0
Other Interest Charges	0	0	0	3,104	0
Other Income Deductions	0	0	0	0	0
NET OPERATING INCOME (or Loss)	$0	($18,957)	$3,704	$23,645	$0

[A] Company did not file an annual report in time to be included.

Rate Regulated Water Utilities - Class C

Financial Data and Sales Statistics

Year Ending December 31, 2024

	Clearwater Source LLC	DWF Round Lake Park & Utilities LLC	Helton Water Service LLC [A]	Hillview Water Service LLC [A]	Lakeshore Water Company LLC [B]	Metolius Meadows Property Owners Association [A]
ASSETS & OTHER DEBITS						
Utility Plant	$24,997	$282,000	$0	$0	$0	$0
Less: Depreciation & Amortization Reserve	9,734	0	0	0	0	0
Other Property & Investments	0	0	0	0	0	0
Materials and Supplies	0	0	0	0	0	0
Other Current & Accrued Assets	0	0	0	0	0	0
Deferred Debits	0	0	0	0	0	0
Total Assets & Other Debits	$15,263	$282,000	$0	$0	$0	$0
LIABILITIES & OTHER CREDITS						
Capital/Common Stock	$0	$0	$0	$0	$0	$0
Retained Earnings	15,263	(35,827)	0	0	0	0
Long-Term Debt	0	0	0	0	0	0
Customer Deposits	0	0	0	0	0	0
Other Current & Accrued Liabilities	0	0	0	0	0	0
Advances for Construction	0	0	0	0	0	0
Other Deferred Credits	0	0	0	0	0	0
Contributions in Aid of Construction	0	0	0	0	0	0
Accumulated Deferred Income Taxes	0	0	0	0	0	0
Total Liabilities & Other Credits	$15,263	($35,827)	$0	$0	$0	$0
AVERAGE NUMBER OF CUSTOMERS						
Flat Rate	0	69	0	0	0	0
Metered - Residential	22	0	0	0	0	0
Metered - Commercial	0	0	0	0	0	0
Irrigation (including golf courses)	0	0	0	0	0	0
Fire Protection	0	0	0	0	0	0
Other	0	0	0	0	0	0
Total Customers	22	69	0	0	0	0

[A] Company did not file an annual report in time to be included.

[B] Company filed annual report as confidential.

Rate Regulated Water Utilities - Class C

Financial Data and Sales Statistics

Year Ending December 31, 2024

	Clearwater Source LLC	DWF Round Lake Park & Utilities LLC	Helton Water Service LLC [A]	Hillview Water Service LLC [A]	Lakeshore Water Company LLC [B]	Metolius Meadows Property Owners Association [A]
OPERATING REVENUES						
Flat Rate	$0	$0	$0	$0	$0	$0
Metered - Residential	23,542	60,505	0	0	0	0
Metered - Commercial	0	0	0	0	0	0
Irrigation (including golf courses)	0	0	0	0	0	0
Fire Protection	0	0	0	0	0	0
Other Sales of Water	0	0	0	0	0	0
Other Operating Revenue	0	0	0	0	0	0
Total Operating Revenues	$23,542	$60,505	$0	$0	$0	$0
OPERATING EXPENSES						
Purchased Water	$7,823	$544	$0	$0	$0	$0
Purchased Power	0	14,444	0	0	0	0
Water Treatment	100	3,095	0	0	0	0
Supplies and Expenses	3,128	18,507	0	0	0	0
Repairs of Plant	0	7,535	0	0	0	0
Administrative & General	7,725	52,207	0	0	0	0
Total Operating Expenses	$18,776	$96,332	$0	$0	$0	$0
OTHER REVENUE DEDUCTIONS						
Depreciation & Amortization	$1,347	$0	$0	$0	$0	$0
Operating Income Taxes	0	0	0	0	0	0
Other Operating Taxes	455	0	0	0	0	0
Uncollectible Revenue/Bad Debt Expense	0	10,000	0	0	0	0
Total Revenue Deductions	$1,802	$10,000	$0	$0	$0	$0
Total Expenses and Deductions	$20,578	$106,332	$0	$0	$0	$0
Other Income	$0	$0	$0	$0	$0	$0
Interest on Long-Term Debt	0	0	0	0	0	0
Other Interest Charges	0	0	0	0	0	0
Other Income Deductions	0	0	0	0	0	0
NET OPERATING INCOME (or Loss)	$2,964	($45,827)	$0	$0	$0	$0

[A] Company did not file an annual report in time to be included.

[B] Company filed annual report as confidential.

Rate Regulated Water Utilities - Class C

Financial Data and Sales Statistics

Year Ending December 31, 2024

	North Hill Water Corporation [A]	Old Sheep Ranch Water Association	Seavey Loop Water Holdings LLC [B]	Seventh Mtn. Golf Village Water Company	Shadow Wood Water Service LLC [A]	South Coast Water District, Inc. [B]
ASSETS & OTHER DEBITS						
Utility Plant	$0	$31,975	$0	$160,372	$0	$0
Less: Depreciation & Amortization Reserve	0	920	0	142,250	0	0
Other Property & Investments	0	0	0	0	0	0
Materials and Supplies	0	0	0	0	0	0
Other Current & Accrued Assets	0	0	0	0	0	0
Deferred Debits	0	0	0	0	0	0
Total Assets & Other Debits	$0	$31,055	$0	$18,122	$0	$0
LIABILITIES & OTHER CREDITS						
Capital/Common Stock	$0	$0	$0	$30,271	$0	$0
Retained Earnings	0	31,055	0	(79,680)	0	0
Long-Term Debt	0	0	0	0	0	0
Customer Deposits	0	0	0	0	0	0
Other Current & Accrued Liabilities	0	0	0	67,531	0	0
Advances for Construction	0	0	0	0	0	0
Other Deferred Credits	0	0	0	0	0	0
Contributions in Aid of Construction	0	0	0	0	0	0
Accumulated Deferred Income Taxes	0	0	0	0	0	0
Total Liabilities & Other Credits	$0	$31,055	$0	$18,122	$0	$0
AVERAGE NUMBER OF CUSTOMERS						
Flat Rate	0	0	0	0	0	0
Metered - Residential	0	35	0	189	0	0
Metered - Commercial	0	0	0	3	0	0
Irrigation (including golf courses)	0	0	0	2	0	0
Fire Protection	0	0	0	0	0	0
Other	0	0	0	0	0	0
Total Customers	0	35	0	194	0	0

[A] Company did not file an annual report in time to be included.

[B] Company filed annual report as confidential.

Rate Regulated Water Utilities - Class C

Financial Data and Sales Statistics

Year Ending December 31, 2024

	North Hill Water Corporation [A]	Old Sheep Ranch Water Association	Seavey Loop Water Holdings LLC [B]	Seventh Mtn. Golf Village Water Company	Shadow Wood Water Service LLC [A]	South Coast Water District, Inc. [B]
OPERATING REVENUES						
Flat Rate	$0	$0	$0	$0	$0	$0
Metered - Residential	0	15,923	0	51,931	0	0
Metered - Commercial	0	0	0	2,794	0	0
Irrigation (including golf courses)	0	0	0	8,732	0	0
Fire Protection	0	0	0	0	0	0
Other Sales of Water	0	0	0	0	0	0
Other Operating Revenue	0	0	0	0	0	0
Total Operating Revenues	$0	$15,923	$0	$63,457	$0	$0
OPERATING EXPENSES						
Purchased Water	$0	$0	$0	$0	$0	$0
Purchased Power	0	931	0	26,465	0	0
Water Treatment	0	1,155	0	120	0	0
Supplies and Expenses	0	4,572	0	4,541	0	0
Repairs of Plant	0	385	0	0	0	0
Administrative & General	0	2,500	0	28,291	0	0
Total Operating Expenses	$0	$9,543	$0	$59,417	$0	$0
OTHER REVENUE DEDUCTIONS						
Depreciation & Amortization	$0	$920	$0	$2,578	$0	$0
Operating Income Taxes	0	0	0	150	0	0
Other Operating Taxes	0	0	0	4,026	0	0
Uncollectible Revenue/Bad Debt Expense	0	0	0	0	0	0
Total Revenue Deductions	$0	$920	$0	$6,754	$0	$0
Total Expenses and Deductions	$0	$10,463	$0	$66,171	$0	$0
Other Income	$0	$0	$0	$0	$0	$0
Interest on Long-Term Debt	0	0	0	0	0	0
Other Interest Charges	0	0	0	0	0	0
Other Income Deductions	0	0	0	0	0	0
NET OPERATING INCOME (or Loss)	$0	$5,460	$0	($2,714)	$0	$0

[A] Company did not file an annual report in time to be included.

[B] Company filed annual report as confidential.

Rate Regulated Water Utilities - Class C

Financial Data and Sales Statistics

Year Ending December 31, 2024

	South Hills Water System, Inc.	Storlie Water Company [A]	Tierra Del Mar Water Company	Westwood Water System LLC [A]	Wilderness Canyon Water LLC [A]
ASSETS & OTHER DEBITS					
Utility Plant	$142,476	$0	$685,491	$0	$0
Less: Depreciation & Amortization Reserve	116,094	0	414,086	0	0
Other Property & Investments	36,844	0	4,388	0	0
Materials and Supplies	0	0	13,676	0	0
Other Current & Accrued Assets	0	0	42,374	0	0
Deferred Debits	0	0	62,648	0	0
Total Assets & Other Debits	$63,226	$0	$394,491	$0	$0
LIABILITIES & OTHER CREDITS					
Capital/Common Stock	$2,387	$0	$106,265	$0	$0
Retained Earnings	60,839	0	(43,960)	0	0
Long-Term Debt	0	0	0	0	0
Customer Deposits	0	0	3,924	0	0
Other Current & Accrued Liabilities	0	0	3,940	0	0
Advances for Construction	0	0	0	0	0
Other Deferred Credits	0	0	177,518	0	0
Contributions in Aid of Construction	0	0	146,804	0	0
Accumulated Deferred Income Taxes	0	0	0	0	0
Total Liabilities & Other Credits	$63,226	$0	$394,490	$0	$0
AVERAGE NUMBER OF CUSTOMERS					
Flat Rate	0	0	0	0	0
Metered - Residential	105	0	271	0	0
Metered - Commercial	0	0	5	0	0
Irrigation (including golf courses)	0	0	0	0	0
Fire Protection	0	0	0	0	0
Other	0	0	0	0	0
Total Customers	105	0	276	0	0

[A] Company did not file an annual report in time to be included.

Rate Regulated Water Utilities - Class C

Financial Data and Sales Statistics

Year Ending December 31, 2024

	South Hills Water System, Inc.	Storlie Water Company [A]	Tierra Del Mar Water Company	Westwood Water System LLC [A]	Wilderness Canyon Water LLC [A]
OPERATING REVENUES					
Flat Rate	$0	$0	$0	$0	$0
Metered - Residential	49,269	0	70,555	0	0
Metered - Commercial	0	0	1,422	0	0
Irrigation (including golf courses)	0	0	0	0	0
Fire Protection	0	0	0	0	0
Other Sales of Water	0	0	0	0	0
Other Operating Revenue	6,000	0	25,057	0	0
Total Operating Revenues	$55,269	$0	$97,033	$0	$0
OPERATING EXPENSES					
Purchased Water	$0	$0	$0	$0	$0
Purchased Power	2,989	0	1,898	0	0
Water Treatment	1,420	0	3,962	0	0
Supplies and Expenses	13,132	0	29,688	0	0
Repairs of Plant	7,458	0	5,457	0	0
Administrative & General	8,025	0	25,395	0	0
Total Operating Expenses	$33,024	$0	$66,401	$0	$0
OTHER REVENUE DEDUCTIONS					
Depreciation & Amortization	$2,684	$0	$10,820	$0	$0
Operating Income Taxes	150	0	0	0	0
Other Operating Taxes	2,095	0	5,074	0	0
Uncollectible Revenue/Bad Debt Expense	0	0	0	0	0
Total Revenue Deductions	$4,929	$0	$15,894	$0	$0
Total Expenses and Deductions	$37,953	$0	$82,294	$0	$0
Other Income	$0	$0	$0	$0	$0
Interest on Long-Term Debt	0	0	0	0	0
Other Interest Charges	0	0	0	0	0
Other Income Deductions	0	0	0	0	0
NET OPERATING INCOME (or Loss)	$17,316	$0	$14,739	$0	$0

[A] Company did not file an annual report in time to be included.

Chapter 285B

1999 EDITION

Economic Development II

BUSINESS DEVELOPMENT PROJECTS

285B.050 Definitions for ORS 285B.050 to 285B.098

285B.053 Borrowing money from Oregon Business Development Fund for projects

285B.056 Evaluation of project; fee

285B.059 Conditions for commission approval of project; preferences; limits

285B.062 Agreement for project loan; required provisions; interest rate; discount for early repayment

285B.065 Loans in distressed areas exempt from requirements of ORS 285B.059 and 285B.062

285B.068 Payment of moneys for project; applicant to pay percentage of loan principal to Oregon Business Development Fund

285B.071 Authority to obtain moneys to repay fund

285B.074 Contract for loan service; fee

285B.077 Report required

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Note: The name of the Department of Human Resources has been changed to the Department of Human Services and the title of the Director of Human Resources to the Director of Human Services. The name and title changes become operative on July 1, 2000. See sections 10 and 11, chapter 421, Oregon Laws 1999. References to the department and the director in this chapter use the name and the title that become operative on July 1, 2000.

Note: 285A.010 contains definitions for ORS chapter 285B.

BUSINESS DEVELOPMENT PROJECTS

285B.050 Definitions for ORS 285B.050 to 285B.098. As used in ORS 285B.050 to 285B.098, unless the context requires otherwise:

(1) "Business development project" means the acquisition, engineering, improvement, rehabilitation, construction, operation or maintenance of any property, real or personal, that is used or is suitable for use by an economic enterprise and that will result in, or will aid, promote or facilitate, development of one or more of the following activities:

(a) Manufacturing or other industrial production;

(b) Agricultural development or food processing;

(c) Aquacultural development or seafood processing;

(d) Development or improved utilization of natural resources;

(e) Convention facilities and trade centers;

(f) Transportation or freight facilities; and

(g) Other activities that represent new technology or type of economic enterprise the Oregon Economic and Community Development Commission determines is needed to diversify the economic base of an area but not including:

(A) Construction of office buildings, including corporate headquarters; and

(B) Retail businesses, shopping centers or food service facilities.

(2) "Commission" means the Oregon Economic and Community Development Commission established under ORS 285A.040.

(3) "Fund" means the Oregon Business Development Fund.

(4) "Collateral" means property subject to a security interest, as defined in ORS 79.1050.

(5) "Municipality" means any city, municipal corporation or quasi-municipal corporation.

(6) "Person" means any individual, association of individuals, joint venture, partnership or corporation.

(7) "Local development group" means any public or private corporation which has as one of its primary purposes, as stated in its articles of incorporation, charter or bylaws, the promotion of economic development in any part of the State of Oregon.

(8) "Applicant" means any county, municipality, person or any combination of counties, municipalities or persons applying for a loan from the Oregon Business Development Fund under ORS 285B.050 to 285B.098.

(9) "Owned and operated by women and minorities" means, with regard to any specific business enterprise, the ownership or control of more than 50 percent of the units of proprietary or ownership interest in that business enterprise by individuals who are women or members of minorities, as defined by ORS 430.347 (2).

(10) "Emerging small business" has the meaning given that term by ORS 200.005.

(11) "County" means any county or federally recognized Oregon Indian tribe. [Formerly 285.403]

285B.053 Borrowing money from Oregon Business Development Fund for projects. (1) Any county, municipality, person or any combination of counties, municipalities and persons may file with the Oregon Economic and Community Development Commission an application to borrow money from the Oregon Business Development Fund for a business development project as provided in ORS 285B.050 to 285B.098. The application shall be filed in such a manner and contain or be accompanied by such information as the commission may prescribe.

(2) Any applicant receiving a loan from the Oregon Business Development Fund shall annually report to the Economic and Community Development Department the estimated number of jobs created as a result of the business development project financed under ORS 285B.050 to 285B.098. The reporting requirement under this section shall continue for five years following the receipt of the loan proceeds or for the life of the loan, whichever period is longer. Agreement to comply with the requirements of this section shall be a condition for obtaining a loan from the Oregon Business Development Fund. [Formerly 285.405]

285B.056 Evaluation of project; fee. (1) Upon receipt of an application under ORS 285B.053, the Oregon Economic and Community Development Commission shall determine whether the plans and specifications for the proposed business development project set forth in or accompanying the application are satisfactory. If the commission determines that the plans and specifications are not satisfactory, it shall:

(a) Reject the application with a written statement of the reason for that rejection; or

(b) Require the applicant to submit additional information of the plans and specifications as may be necessary.

(2) The commission shall charge and collect from the applicant, at the time the application is filed, a fee not to exceed $100. Moneys referred to in this subsection shall be paid into the Oregon Business Development Fund. [Formerly 285.410]

285B.059 Conditions for commission approval of project; preferences; limits. (1) The Oregon Economic and Community Development Commission may approve a business development project proposed in an application filed under ORS 285B.050 to 285B.098 if, after investigation, it finds that:

(a) The proposed business development project is feasible and a reasonable risk from practical and economic standpoints, and the loan has reasonable prospect of repayment.

(b) The applicant can provide good and sufficient collateral for the loan.

(c) Moneys in the Oregon Business Development Fund are or will be available for the proposed business development project.

(d) There is a need for the proposed business development project, and the applicant's financial resources are adequate to assure success of the project.

(e) If the proposed project is to be located in an incorporated city, the governing body of that city has executed a resolution recommending the proposed project.

(f) If the proposed project is to be located outside any incorporated city, the governing body of the county in which the project is to be located has executed a resolution recommending the proposed project.

(g) The Housing and Community Services Department received notification of the proposed project and any related workforce increase at the time the application was received by the commission.

(h) The applicant has not received or entered into a contract or contracts exceeding $500,000 with the commission, under authority of ORS 285B.050 to 285B.098, for the previous 365 days, nor is there an amount equal to 20 percent of the total value of the fund in outstanding loans with the commission at any one time for business development projects located in the same county as the proposed project. However, nothing in this paragraph prevents the commission from making a loan to an emerging small business, as provided in subsection (6) of this section, or making a loan of less than $100,000, as provided in ORS 285B.080.

(2) Preference shall be given to a business development project which has a high ratio of employment to the amount of money sought to be borrowed from the Oregon Business Development Fund, which benefits businesses with fewer than 50 employees or which is located within a rural area of the state. Consideration also shall be given to the extent of participation by local development groups, and the availability and cost of money to the applicant from, or through, commercial lending or financial institutions, or other financial sources, inasmuch as the Oregon Business Development Fund is intended to complement, not supplant, other sources of money for economic development.

(3) The total amount of moneys loaned from the fund for any business development project shall not exceed 50

percent of the cost of the project. Working capital equity contributed by the applicant or a related party shall not be included in the calculation of total project costs.

(4) Except in cases where the applicant is a county or municipality, no money shall be loaned from the fund for any business development project unless there exists a commitment from a commercial or private lender, or a local development group, to participate in the financing of the project.

(5) To encourage private sector and local development group participation in the financing of business development projects, the commission may subordinate the security position of the fund to that of other lenders.

(6) In each fiscal year of a biennium, not less than 15 percent of all moneys available for lending from the Oregon Business Development Fund are reserved for loans to certified emerging small business enterprises which are located in or draw their workforces from within distressed communities as determined by the Economic and Community Development Department in cooperation with the Employment Department of this state. Any amounts reserved for loans to such businesses that are not loaned in one fiscal year shall be added to the amount reserved for loans to such businesses in the subsequent fiscal year. If the Economic and Community Development Department is unable to obtain a sufficient number of approvable applications to meet the requirements of this subsection, it may, notwithstanding the limitations imposed by ORS 285B.050 (1)(g)(B), make loans to service and retail businesses operated by certified emerging small business enterprises.

(7) In the operation of the Oregon Business Development Fund, the commission and the department shall, to the maximum extent feasible and consistent with constitutional limitations, seek to assure that an amount equal to that specified in subsection (6) of this section be loaned to businesses owned and operated by women and minorities. [Formerly 285.413; 1999 c.509 s.27]

285B.062 Agreement for project loan; required provisions; interest rate; discount for early repayment. If the Oregon Economic and Community Development Commission approves the business development project, the commission, on behalf of the state, and the applicant may enter into a loan contract of not more than $500,000, secured by good and sufficient collateral, which shall set forth, among other matters:

(1) A plan for repayment by the applicant to the Oregon Business Development Fund moneys borrowed from the fund used for the business development project with interest charged on those moneys at the rate of not less than one percentage point more than the prevailing interest rate on United States Treasury bills, notes or bonds of a comparable term, as determined by the commission. However, the commission may make such loans to emerging small businesses, as defined in ORS 200.005, at a rate of not less than one percentage point less than such prevailing interest rate. The repayment plan, among other matters:

(a) Shall provide for commencement of repayment by the applicant of moneys used for the business development project and interest thereon no later than one year after the date of the loan contract or at such other time as the commission may provide.

(b) May provide for reasonable extension of the time for making any repayment in emergency or hardship circumstances if approved by the commission.

(c) Shall provide for such evidence of debt assurance of, and security for, repayment by the applicant as is considered necessary by the commission.

(d) Shall set forth a schedule of payments and the period of loan which shall not exceed the usable life of the contracted project or 20 years from the date of the contract, whichever is less, and shall also set forth the manner of determining when loan payments are delinquent. The payment schedule shall include repayment of interest which accrues during any period of delay in repayment authorized by paragraph (a) of this subsection, and the payment schedule may require payments of varying amounts for collection of accrued interest.

(e) Shall set forth a procedure for formal declaration of default of payment by the commission, including formal notification of all relevant federal, state and local agencies; and further, a procedure for notification of all relevant federal, state and local agencies that declaration of default has been rescinded when appropriate.

(f) May offer a discount not to exceed 10 percent of the outstanding principal for the early repayment of the entire outstanding principal of any loan. The commission by rule shall adopt policies that provide for greater discounts for earlier repayments and that provide for greater discounts for firms that have created at least one job per each $15,000 loaned to the firm from the Oregon Business Development Fund.

(2) Provisions satisfactory to the commission for field engineering and inspection, the commission to be the final judge of completion of the contract.

(3) That the liability of the state under the contract is contingent upon the availability of moneys in the Oregon Business Development Fund for use in the business development project.

(4) Such further provisions as the commission considers necessary to insure expenditure of the funds for the purposes set forth in the approved application.

(5) That the commission may institute appropriate action or suit to prevent use of the facilities of a business development project financed by the Oregon Business Development Fund if the applicant is delinquent in the repayment of any moneys due the fund. [Formerly 285.415]

285B.065 Loans in distressed areas exempt from requirements of ORS 285B.059 and 285B.062. The Economic and Community Development Department may make loans in distressed areas, as defined by the department, without regard to the requirements for security and collateral under ORS 285B.059 and 285B.062 that are otherwise applicable. [Formerly 285.416]

285B.068 Payment of moneys for project; applicant to pay percentage of loan principal to Oregon Business Development Fund. (1) If the Oregon Economic and Community Development Commission approves a loan for a business development project and the applicant has received all necessary permits required by federal, state and local agencies, the commission shall pay moneys for the project from the Oregon Business Development Fund, in accordance with the terms of the loan contract as prescribed by the commission.

(2) Immediately upon receiving the loan proceeds, the applicant shall pay to the commission one and one-half percent of the principal amount of the loan, to be paid back to the Oregon Business Development Fund. A maximum of three percent of the principal amount of the loan may be paid from the fund to local development groups for the purposes set forth in ORS 285B.092 (1)(a). [Formerly 285.417]

285B.071 Authority to obtain moneys to repay fund. Any county or municipality that enters into a contract with the Oregon Economic and Community Development Commission for a business development project and repayment as provided in ORS 285B.062 may obtain moneys for repayment to the Oregon Business Development Fund under the contract in the same manner as other moneys are obtained for purposes of the county or municipality or other moneys available to the developer. [Formerly 285.420]

285B.074 Contract for loan service; fee. The Economic and Community Development Department may, by contract, provide for local business development funds to service outstanding loans from the Oregon Business Development Fund. The department may provide for a fee of up to two percent of the outstanding loan balance on such loans to compensate local business development funds for services provided under this section. [Formerly 285.425]

285B.077 Report required. The Oregon Economic and Community Development Commission shall submit to the Legislative Assembly and the Governor a biennial report of the transactions of the Oregon Business Development Fund in such detail as will adequately indicate the condition of the fund. [Formerly 285.430]

285B.080 Director as agent; limitation on authority. (1) The Oregon Economic and Community Development Commission may appoint the Director of the Economic and Community Development Department as its representative and agent in all matters pertaining to ORS 285B.050 to 285B.098.

(2) The director shall ensure that all provisions of ORS 285B.050 to 285B.098 are complied with and that appropriately trained personnel are employed to properly administer the fiscal and other portions of ORS 285B.050 to 285B.098.

(3) The director shall have the authority in the director's sole discretion to approve loans for business development projects in the amount of $100,000 or less and to disburse funds for such projects. [Formerly 285.433]

285B.083 Use of refinancing and other financial assistance. Except as provided in ORS 285B.086, if any business development project is refinanced or financial assistance is obtained from other sources after the execution of the loan from the state, those shall be first used to repay the state, unless provided otherwise by the committee, if the refinancing or financial assistance applies only to the business development project authorized and does not include any subsequent addition, expansion, improvement or further development. [Formerly 285.435]

285B.086 Authority to lend funds for joint governmental projects or match money; form of loan application; loan limit. (1) The Oregon Economic and Community Development Commission may authorize funds from the Oregon Business Development Fund to be used in appropriate joint governmental participation projects or as match

money with any municipally, county, state or federally funded business development project authorized within a county or city, subject to the stipulations of ORS 285B.050 to 285B.098.

(2) Any application for a loan under this section shall be in such form as the commission prescribes and shall furnish such proof of federal, state or local approval as appropriate for funding of the business development project.

(3) The total amount of moneys loaned from the fund for federal, state or local joint business development project purposes shall not exceed $500,000 per project. [Formerly 285.437]

285B.089 Loan contract; required provisions. If the Oregon Economic and Community Development Commission approves an application for the loan of moneys authorized by ORS 285B.086, the commission shall enter into a loan contract, secured by good and sufficient collateral, with the applicant that provides, among other matters:

(1) That the loan bear interest at the same rate of interest as provided in ORS 285B.062 (1).

(2) That the contract shall set forth a schedule of payments including interest and principal for the period of the loan, which shall not exceed the usable life of the contracted project or 25 years from the date of the contract, whichever is less, and shall set forth the manner of determining when loan payments are delinquent. The same schedule shall include repayment of interest which accrues during any period of delay in repayment authorized by ORS 285B.050 to 285B.098, and the repayment schedule may require payments of varying amounts for collection of that accrued interest. However, the commission may make provisions for extensions of time in making repayment if the delinquencies are caused by acts of God or other conditions beyond the control of the applicant and the security will not be impaired thereby.

(3) Such provisions as the commission considers necessary to insure expenditure of the moneys loaned for the purposes provided in ORS 285B.086, including all provisions of ORS 285B.059. [Formerly 285.440]

285B.092 Oregon Business Development Fund; uses. (1) There is created within the State Treasury a revolving fund known as the Oregon Business Development Fund, separate and distinct from the General Fund. Interest earned by the fund shall be credited to the fund. Moneys in this fund are continuously appropriated to the Oregon Economic and Community Development Commission for the following purposes:

(a) Administrative expenses of the commission in marketing public business finance, processing applications, investigating proposed business development projects and servicing outstanding loans. In any one year, administrative expenses charged under this paragraph may not be greater than the total revenues received in that year from fees provided for in subsection (2)(a) of this section, plus four percent of the total asset value of the fund.

(b) Payment of loans to applicants under ORS 285B.050 to 285B.098.

(c) Transfers of moneys as provided in ORS 285B.374 (4)(a).

(d) Purchase or buy out of superior or prior liens or mortgages on or a security interest in any business development project financed in part by a loan from the fund, when the commission determines:

(A) A loan from the fund is in default and is in liquidation or at risk of being forced into liquidation by another creditor to the project;

(B) Such action is necessary to maintain or enhance the value of the commission's collateral in the project; and

(C) The amount of the purchase or buyout of superior or prior liens or mortgages on that project does not exceed $500,000.

(2) The fund created by subsection (1) of this section shall consist of:

(a) Fees required by ORS 285B.056 (2) and 285B.068 (2).

(b) Repayment of moneys loaned to counties, municipalities or persons from the Oregon Business Development Fund, including interest on those moneys.

(c) Payment of such moneys as may be appropriated to the fund by the Legislative Assembly.

(d) Moneys obtained from any interest accrued from funds.

(e) Moneys from any grant made to the fund by any federal agency.

(3) Notwithstanding any other law, if at any time there are insufficient funds in the Oregon Entrepreneurial Development Loan Fund established by ORS 285B.758, the Director of the Economic and Community Development Department may direct the transfer of unobligated funds from the Oregon Business Development Fund to the Oregon Entrepreneurial Development Loan Fund. Transfers under this subsection shall be in amounts necessary to meet the reasonably foreseeable demand for participation in the entrepreneurial loan program. [Formerly 285.443; 1999 c.247 s.3; 1999 c.509 s.28]

285B.093 Oregon Targeted Development Account; purpose. (1) The Oregon Economic and Community

Development Commission may establish the Oregon Targeted Development Account as an account within the Oregon Business Development Fund.

(2) If the account is established, the purpose of the Oregon Targeted Development Account is to promote cooperation and foster partnership among the commission, the Economic and Community Development Department and financial institutions in Oregon to encourage investment in distressed areas, as defined by the department.

(3) The Economic and Community Development Department may make loans from the Oregon Targeted Development Account in distressed areas without regard to the minimum rate of interest that is otherwise applicable under ORS 285B.062. The department may make loans in distressed areas at an interest rate that is determined by the Oregon Economic and Community Development Commission.

(4) ORS 285B.059 (1)(e) to (g), (2) and (5) does not apply to business development projects financed wholly or in part with moneys from the Oregon Targeted Development Account. [1999 c.247 s.1]

285B.095 Retention and use of payments, receipts and interest. All payments, receipts and interest from outstanding indebtedness or any other source shall be retained and accumulated in the Oregon Business Development Fund and shall be used for the purposes of the fund. [Formerly 285.445]

285B.098 Status of loan to county or municipality. A loan made to a county or municipality under ORS 285B.050 to 285B.098 shall not be a general obligation of that county or municipality, nor a charge upon the tax revenues of that county or municipality, nor a charge upon any other revenues or property of that county or municipality not specifically pledged thereto. A loan made to a county or municipality under ORS 285B.050 to 285B.098 may be secured by the business development project for which the loan is made, as well as by any revenues derived from that project, and any nontax-derived revenues or property of the county or municipality not otherwise pledged or committed for other purposes. A county or municipality may repay any portion of a loan incurred under ORS 285B.050 to 285B.098 from any funds available to it. [Formerly 285.447]

SMALL BUSINESS DEVELOPMENT

(Generally)

285B.120 Oregon Small Business Development Act. ORS 271.510, 271.520, 285B.092, 285B.123, 285B.165 to 285B.171, 285B.320 to 285B.326, 285B.335, 285B.341, 285B.344, 285B.350, 285B.365, 285B.371 to 285B.377, 657.471, 659.027 and 777.250 shall be known as the Oregon Small Business Development Act of 1983. [Formerly 285.500]

285B.123 Policy. (1) The Legislative Assembly finds that:

(a) Small businesses comprise more than 97 percent of the business entities in this state.

(b) Small businesses provide more than three-quarters of the private sector jobs in this state.

(c) The small business contribution to the economy of this state exceeds the national average contribution and its continuance is vital to the economic health and growth of this state.

(d) All national economic indicators establish that the greatest source of future new jobs is in the small business sector of the economy.

(2) The purpose of the Oregon Small Business Development Act of 1983 is to encourage and assist the development and continued growth of small business in this state.

(3) As used in the Oregon Small Business Development Act of 1983, “small business” means a manufacturing business having 200 or fewer employees and all other forms of business having 50 or fewer employees.

(4) The provisions of ORS 285B.120 and 657.471 are intended to assist in carrying out the Oregon Small Business Development Act of 1983. [Formerly 285.503]

(Capital Access for Small Businesses)

285B.126 Definitions for ORS 285B.126 to 285B.147. As used in ORS 285B.126 to 285B.147, unless the context requires otherwise:

(1) “Financial institution” means a financial institution, as defined in ORS 706.008.

(2) “Loss reserve account” means an account in the State Treasury or any financial institution which is established

and maintained by the Economic and Community Development Department for the benefit of a financial institution participating in the capital access program established under ORS 285B.126 to 285B.147.

(3) "Qualified business" means any person, conducting business for profit or not for profit, that is authorized to conduct business in the State of Oregon.

(4) "Qualified loan" means a loan or portion of a loan made by a financial institution to a qualified business for any business activity that has its primary economic effect in Oregon. The term does not include:

(a) A loan for the construction or purchase of residential housing.

(b) A loan for purchase of real property that is not used for the business operations of the borrower.

(c) A loan for the refinancing of an existing loan when and to the extent that the outstanding balance is not increased. [Formerly 285.507]

285B.129 Policy. (1) The Legislative Assembly finds that:

(a) There is a persistent shortage of equity capital available to small businesses in Oregon.

(b) Small businesses make important contributions to economic growth and vitality in this state.

(c) Many financial institutions in Oregon are limited in their ability to provide financing to small but rapidly growing businesses.

(2) It is the purpose of ORS 285B.126 to 285B.147 to establish a capital access program under which the State of Oregon will provide public fiscal resources to assist Oregon financial institutions to overcome obstacles and constraints in meeting the full range of economically sound financing needs of Oregon businesses. [Formerly 285.510]

285B.132 Contracts with financial institutions for capital access; contents of contract; status of information. (1) The Economic and Community Development Department may contract with any financial institution for the purpose of allowing the financial institution to participate in the capital access program established by ORS 285B.126 to 285B.147.

(2) A contract between the Economic and Community Development Department and a financial institution under this section shall provide:

(a) For the creation of a loss reserve account by the department for the benefit of the financial institution.

(b) That the financial institution, qualified business and the department will deposit moneys to the credit of the institution's loss reserve account when the financial institution makes a qualified loan to a qualified business.

(c) That the department will pay moneys in the loss reserve account, not exceeding an amount equal to the total amount credited to the loss reserve account, to the financial institution to reimburse the institution for any financial loss incurred as a result of any qualified loan made under the capital access program established by ORS 285B.126 to 285B.147.

(d) That the liability of the State of Oregon and the Economic and Community Development Department to the financial institution under the contract is limited to the amount of money credited to the loss reserve account of the institution.

(e) That the financial institution shall provide such information as the department may require, including financial information that is identifiable with, or identifiable from, the financial records of a particular customer who is the recipient of a qualified loan.

(f) For such other terms as the department may require.

(3) A financial institution is not subject to ORS 192.555 (1) when the financial institution provides information to the Economic and Community Development Department as required by subsection (2)(e) of this section. [Formerly 285.513]

285B.135 Loss reserve accounts; limitation on amount. (1) The Economic and Community Development Department shall establish a loss reserve account for each financial institution with which the department makes a contract under ORS 285B.132.

(2) The loss reserve account for a financial institution shall consist of moneys paid as fees by borrowers and the financial institution under ORS 285B.138 and moneys transferred to the account from the Capital Access Fund under ORS 285B.138.

(3) Notwithstanding ORS chapter 293 or 295, the department may establish and maintain loss reserve accounts with any financial institution under such policies as the department may adopt.

(4) All moneys in a loss reserve account established under ORS 285B.126 to 285B.147 are the property of the State of Oregon.

(5) The amounts transferred from the Capital Access Fund to a loss reserve account on behalf of any single qualified business shall not exceed $150,000. [Formerly 285.515]

285B.138 Enrollment of qualified loan in program; procedure; fee; transfers to loan reserve account. (1) When a financial institution participates in the capital access program established by ORS 285B.126 to 285B.147, if the financial institution decides to enroll a qualified loan under the capital access program in order to obtain the protection against loss provided by its loss reserve account, the financial institution shall notify the Economic and Community Development Department of the loan within 30 days after the loan is made. The notification shall be in writing on a form prescribed by the department.

(2) When making a qualified loan that will be enrolled under the capital access program, the financial institution shall require the qualified business to which the loan is made to pay a fee of not less than one and one-half percent of the principal amount of the loan but not more than three and one-half percent of such principal amount. The financial institution shall also pay a fee in an amount equal to the fee paid by the borrower. The financial institution shall deliver the fees collected under this subsection to the department for deposit in the loss reserve account for the institution.

(3) When depositing fees collected under subsection (2) of this section to the credit of the loss reserve account for a financial institution, the department shall transfer an amount that is not less than the total amount of the fees paid by the borrower and the financial institution from the Capital Access Fund to the loss reserve account for the institution. [Formerly 285.517]

285B.139 Exception to minimum amount required for transfer to loss reserve account. Notwithstanding the provisions of ORS 285B.138 (3), the Economic and Community Development Department shall adopt rules that provide that, for qualified loans to businesses in distressed areas, as defined by the department, or for use in the evaluation of brownfields, as defined in ORS 285A.185, the department shall transfer an amount that is not less than 150 percent of the total amount of the fees paid by the borrower and the financial institution from the Capital Access Fund to the loss reserve account of the institution. However, the total amount transferred under this section shall not exceed 40 percent of the moneys appropriated to the Capital Access Fund. [1991 c.688 s.15; 1993 c.765 s.80; 1995 c.71 s.1; 1997 c.738 s.4; 1999 c.247 s.5]

285B.141 Claims for reimbursement of losses; amounts subject to reimbursement. (1) The Economic and Community Development Department shall establish procedures under which financial institutions participating in the capital access program established by ORS 285B.126 to 285B.147 may submit claims for reimbursement for losses incurred as a result of qualified loan defaults.

(2) Costs for which a financial institution may be reimbursed from its loss reserve account include loan principal, accrued interest on the principal, actual and necessary costs of seeking recovery of the principal amount and interest thereon and any other related costs.

(3) A financial institution may seek reimbursement of loan losses prior to the liquidation of collateral from defaulted loans. The financial institution shall repay its loss reserve account for any moneys received as reimbursement under this section if the financial institution recovers moneys from the borrower or from the liquidation of collateral for the defaulted loan. [Formerly 285.520]

285B.144 Financial report of Capital Access Fund. (1) The Economic and Community Development Department shall annually prepare a report conforming to generally accepted accounting principles that describes the financial condition of the Capital Access Fund.

(2) The reports required under this section shall be submitted to the Governor and to the Joint Legislative Committee on Trade and Economic Development. [Formerly 285.525]

285B.147 Capital Access Fund; use; investment earnings; administrative expenses. (1) There is established in the State Treasury, separate and distinct from the General Fund, the Capital Access Fund. All moneys in the fund are continuously appropriated to the Economic and Community Development Department for the purpose of making payments to loss reserve accounts established under ORS 285B.126 to 285B.147.

(2) Moneys in the Capital Access Fund, with the approval of the State Treasurer, may be invested as provided by ORS 293.701 to 293.820, and the earnings from such investment shall be credited to the Capital Access Fund.

(3) The Capital Access Fund shall consist of:

(a) Moneys appropriated to the fund by the Legislative Assembly.

(b) Interest earned on moneys in the fund.

(c) Moneys returned to the fund from loss reserve accounts or other sources.

(4) The Economic and Community Development Department may charge administrative costs to the fund to pay for actual and necessary administrative expenses incurred by the department in administering the fund and establishing and maintaining loss reserve accounts under ORS 285B.126 to 285B.147. [Formerly 285.527]

285B.150 Transfers to Capital Access Fund when insufficient funds available. (1) Notwithstanding any other law, if at any time there are insufficient funds in the Capital Access Fund established by ORS 285B.147 to continue the operation of the program authorized by ORS 285B.126 to 285B.147, the Director of the Economic and Community Development Department may direct the transfer of unobligated funds from the Oregon Business Development Fund to the Capital Access Fund. Such transfers shall be in amounts necessary to meet the reasonably foreseeable demand for participation in the capital access program.

(2) Notwithstanding any other law, if at any time after the transfer of funds provided for in subsection (1) of this section, there are insufficient funds in the Capital Access Fund established by ORS 285B.147 to continue the operation of the program authorized by ORS 285B.126 to 285B.147, the Director of the Economic and Community Development Department may direct the transfer of unobligated funds from the Credit Enhancement Fund to the Capital Access Fund. Such transfers shall be in amounts necessary to meet the reasonably foreseeable demand for participation in the capital access program. The use of funds so transferred shall continue to be governed by ORS 285B.215 (3). [Formerly 285.528]

Note: 285B.150 was enacted into law by the Legislative Assembly but was not added to or made a part of ORS chapter 285B or any series therein by legislative action. See Preface to Oregon Revised Statutes for further explanation.

285B.153 Reservation of Oregon Business Development Fund for small loans. In each fiscal year of a biennium, not less than 17 percent of all moneys available for lending from the Oregon Business Development Fund is reserved for loans to businesses receiving loans in aggregate original principal amount not exceeding $50,000. Any amounts reserved for loans to such businesses that are not loaned in one fiscal year shall be added to the amount reserved for loans to such businesses in the subsequent fiscal year. [Formerly 285.530]

285B.156 [Formerly 285.533; repealed by 1999 c.509 s.61]

(Local Business Development)

285B.159 "Local business development fund" defined. As used in this section and ORS 285B.074 and 285B.162, unless the context requires otherwise, "local business development fund" means a private nonprofit corporation or other nonprofit entity, a public corporation or public agency that makes loans or provides other financial assistance to businesses in this state for the purpose of promoting economic development. [Formerly 285.535]

285B.162 Coordination of marketing and finance programs. The Economic and Community Development Department shall work with local business development funds to strengthen the coordination in the marketing of finance programs for small business, the review and analysis of loan applications and the operation of publicly operated business finance programs. [Formerly 285.537]

(Small Business Development Center)

285B.165 Purpose of ORS 285B.165 to 285B.171. (1) The purpose of ORS 285B.165 to 285B.171 is to establish a statewide network of community college-based small business development centers.

(2) The Legislative Assembly finds that it is in the state's interest to help small businesses develop and improve skills in such areas as marketing, management and capital formation through a network of small business development centers because:

(a) Small business employers create most of the new jobs in Oregon and are vital to Oregon's long term economic recovery;

(b) Community colleges present the possibility of a statewide network able to link small business with college

resources, expert resource people in the business community and with other training resources throughout the state; and

(c) While many factors affect the vitality of small business, training assistance in a form, location and time directly related to the problem to be solved is chief among them. [Formerly 285.540]

285B.168 Grants; application; prohibited uses; eligibility. (1) The Economic and Community Development Department may make available to community college and community college service districts on a justified need basis grants to assist in the formation and improvement of small business development centers. The grant application shall include:

(a) Evidence of the potential demand for assistance;

(b) Plans for involving other training resources and expert resource people from the business community in the program;

(c) An outline of training options to be available, including, but not limited to, time of day, length of training, training location and other considerations important to the small business community;

(d) A budget for the year for which a grant is requested, including college, client and Economic and Community Development Department grant shares; and

(e) A plan for evaluating the effect of the program on small business clients served.

(2) The grants made under subsection (1) of this section are to be used by the community college or community college service district to:

(a) Provide funds for small business development center staff and support staff;

(b) Provide funds to retain expert resource persons from the business community;

(c) Provide funds to retain other training resources as necessary to enhance the training capability of the centers in certain skill areas or areas of the state in instances where the college or district can demonstrate it does not have the capacity or expertise to provide such resources; and

(d) Provide funds for other costs related to operation of the centers and provision of training to small business clients.

(3) In no case shall the grants made under subsection (1) of this section be used for the establishment, maintenance or expansion of other public or private institutions providing similar education services or to establish, maintain or expand satellite centers or business assistance programs operated by other public or private educational institutions.

(4) In order to be eligible for grants under subsection (1) of this section, existing programs shall be required to provide funds or in-kind contributions or some combination of funds and contributions in accordance with rules adopted by the Economic and Community Development Department. [Formerly 285.543]

285B.171 Short title. ORS 285B.165 to 285B.171 shall be known and may be cited as the "Small Business Training Assistance Act." [Formerly 285.547]

(Miscellaneous)

285B.174 Programs to assist businesses in procuring contracts and grants. In cooperation with other state and public agencies, community colleges may develop programs to assist Oregon businesses with the procurement of government contracts and grants. The small business development centers established under ORS 285B.165 to 285B.171 may assist with these programs. [Formerly 285.550]

285B.177 [Formerly 285.553; repealed by 1999 c.509 s.61]

285B.180 [Formerly 285.555; repealed by 1999 c.509 s.61]

CREDIT ENHANCEMENT FUND

285B.200 Definitions for ORS 285B.200 to 285B.218. As used in ORS 285B.200 to 285B.218:

(1) "Department" means the Economic and Community Development Department.

(2) "Eligible project costs" includes productive equipment and machinery, working capital for operations and export transactions and such other costs as the department, by rule, may provide.

(3) "Emerging small business" has the meaning given that term in ORS 200.005.

(4) "Financial institution" includes institutions listed in ORS 706.008 and such other institutions defined by rule of the Economic and Community Development Department as financial institutions for purposes of ORS 285B.200 to 285B.218.

(5) "Qualified business" means any existing or proposed business entity with an average annual employment not exceeding 200 employees that, except when located within a distressed area, as defined by the Economic and Community Development Department, sells goods or services in markets for which national or international competition exists or that owns, occupies, operates or has entered into an agreement to own, occupy or operate real property containing a brownfield, as defined in ORS 285A.185. The term includes professional services companies providing services to traded sector industries and other entities within and outside of this state.

(6) "Value-added agricultural products" means agricultural products that have been processed, transformed or refined to the point where they may be distributed to a final consumer without further processing, transformation or refining. The term also includes agricultural products that are processed, transformed or refined for distribution to other than final consumers when such processing, transformation or refining represents a substantial increment in value as determined by the Economic and Community Development Department in consultation with the State Department of Agriculture. [Formerly 285.466; 1999 c.247 s.4]

Note: 285B.200 to 285B.218 were enacted into law by the Legislative Assembly but were not added to or made a part of ORS chapter 285B by legislative action. See Preface to Oregon Revised Statutes for further explanation.

285B.203 Legislative findings; purpose. (1) The Legislative Assembly finds that:

(a) Small and medium sized businesses in general, and firms that produce value-added agricultural products in particular, are adversely affected by the current credit crisis.

(b) Small companies have historically had a difficult time obtaining credit, especially on terms that allow them to grow and to create jobs.

(c) The limited availability of credit for export transactions limits the ability of small and medium sized businesses in Oregon to compete in international markets.

(d) The challenge for the public economic sector is to design programs, in conjunction with lending institutions in the private economic sector, that fill the gaps in credit availability and export finance.

(e) Without substantial financial assistance to promote redevelopment, properties containing brownfields, as defined in ORS 285A.185, often remain abandoned or underutilized because of the uncertainty concerning environmental contamination at the sites and the cost of reducing or eliminating the contamination.

(2) The Legislative Assembly declares that it is the purpose of the Credit Enhancement Fund established under ORS 285B.215 (1) and (2) to:

(a) Create incentives and assistance to increase the flow of private capital to the value-added agriculture industries.

(b) Promote industrial modernization and technology adoption.

(c) Encourage the retention and creation of family wage jobs.

(d) Encourage the export of goods and services by Oregon businesses in international markets.

(e) Encourage and promote the redevelopment of brownfields, as defined in ORS 285A.185, by providing assistance to perform environmental evaluations of brownfield sites. [Formerly 285.468]

Note: See note under 285B.200.

285B.206 Duties of department under ORS 285B.200 to 285B.218. (1) The Economic and Community Development Department shall develop a program under which the department, under contracts with financial institutions, shall provide loan guarantees, insurance, coinsurance in conjunction with other providers of loan guarantee programs or other forms of credit guarantees for qualified businesses for eligible project costs.

(2) In administering the program created by ORS 285B.200 to 285B.218, the department shall consult and cooperate with financial institutions in this state. The program shall be administered so that administrative procedures and application procedures are as responsive to the needs of qualified businesses and financial institutions as practicable, consistent with prudent investment and lending practices and criteria.

(3) The department shall prescribe by rule the loan or credit guarantee application procedure for a financial institution on behalf of a qualified business.

(4) When the department approves a loan or credit guarantee, the department shall enter into a loan or credit guarantee agreement with the financial institution. The agreement shall specify:

(a) The fee to be charged to the financial institution;

(b) The evidence of debt assurance of, and security for, the loan or credit guarantee;

(c) A loan guarantee or credit guarantee which does not exceed 15 years; and

(d) Such other terms and conditions considered necessary or desirable by the department.

(5) The department may adopt procedures for loan or credit guarantees whereby a qualified business may apply directly to the department for a preliminary guarantee commitment. Such preliminary guarantee commitments may be issued by the department subject to the qualified business securing a commitment for financing from a financial institution. The procedures adopted by the department shall specify the process by which a financial institution may obtain a final loan or credit guarantee. [Formerly 285.474]

Note: See note under 285B.200.

285B.209 Fees and terms for loan and credit guarantees for program under ORS 285B.206 and under ORS 285B.200 to 285B.218. (1) When making loan or credit guarantees under the program established under ORS 285B.206, the Economic and Community Development Department shall establish fees and other terms for loan or credit guarantees that are calculated to reasonably assure that businesses with access to other forms of private capital will find it economical not to participate in the program.

(2) The department, with due regard for the possibility of losses and administrative costs, shall set fees and other terms at levels sufficient to reasonably assure that the program is self-financing.

(3) When making loan or credit guarantees under the program established under ORS 285B.200 to 285B.218, the department shall establish fees and other terms for loan or credit guarantees that are calculated to reasonably assure that qualified businesses with access to other forms of private capital will find it economical not to participate in the program.

(4) With due regard for the possibility of losses and administrative costs, the department shall set fees and other terms at levels sufficient to reasonably assure that the program is self-financing.

(5) For a preliminary guarantee commitment issued under ORS 285B.206 (5), the department may charge the qualified business an application fee. The fee shall be in addition to any other fees charged by the department under this section and may not exceed $250 for each application. [Formerly 285.476]

Note: See note under 285B.200.

285B.212 Commission to advise and make recommendations to department concerning specified programs. The Economic and Community Development Department shall consider the advice and recommendations of the Oregon Economic and Community Development Commission in developing and implementing the programs provided for in ORS 285B.126 to 285B.147, 285B.150 and 285B.200 to 285B.218. [Formerly 285.478]

Note: See note under 285B.200.

285B.215 Credit Enhancement Fund; sources; uses. (1) There is established in the State Treasury, separate and distinct from the General Fund, the Credit Enhancement Fund. All moneys in the fund are continuously appropriated to the Economic and Community Development Department for the following purposes:

(a) Payment of claims pursuant to contracts for loan or credit guarantees under ORS 285B.200 to 285B.218.

(b) Payment of administrative costs of the department for actual and necessary administrative expenses incurred by the department in administering the fund and establishing and maintaining the program established under ORS 285B.200 to 285B.218.

(c) Repayment of transfers of funds required or authorized by law.

(d) Purchase or buyout of superior or prior liens, mortgages or security interests.

(2) Moneys in the Credit Enhancement Fund shall consist of:

(a) Moneys appropriated to the fund by the Legislative Assembly, including moneys derived from the Administrative Services Economic Development Fund.

(b) Proceeds from collateral assigned to the department.

(c) Interest earned on moneys in the fund.

(d) Transfers of moneys to the fund.

(e) Fees assessed for guarantees, as determined by the department.

(f) Moneys from gifts.

(g) Moneys from any grant made to the fund by any federal agency.

(h) Proceeds of insurance provided by the Export-Import Bank of the United States or by any other provider of insurance for export transactions.

(3) In each biennium, not less than 20 percent of all moneys available for loan guarantees from the Credit Enhancement Fund is reserved for loan guarantees to emerging small businesses. [Formerly 285.471]

Note: See note under 285B.200.

285B.218 Pledge to assure repayment of loans or other credit. (1) The Economic and Community Development Department is authorized to pledge up to $75 million to assure the repayment of loan guarantees or other extensions of credit made to or on behalf of qualified businesses for eligible projects costs.

(2) If the balances in the Credit Enhancement Fund are insufficient to cover any claims by financial institutions that arise from loan and credit guarantees made under ORS 285B.200 to 285B.218, the Oregon Department of Administrative Services is directed to transfer in the fiscal year as often as appropriate any funds from the Administrative Services Economic Development Fund to cover such principal, interest and claims, subject to the condition that no such transfer shall be made prior to the satisfaction of the allocation under ORS 391.130 to the Regional Light Rail Extension Construction Fund and the allocation to the Department of Environmental Quality for the debt services described in section 1, chapter 537, Oregon Laws 1993. [Formerly 285.481]

Note: See note under 285B.200.

REGIONAL ECONOMIC DEVELOPMENT

285B.230 Definitions for ORS 285B.230 to 285B.248 and 285B.269. As used in ORS 285B.230 to 285B.248 and 285B.269, unless the context requires otherwise:

(1) “Region” means groups of counties designated by the Economic and Community Development Department or recognized in a regional partnership as provided in ORS 285B.236 (3).

(2) “Regional board” means a board comprised of individuals described in ORS 285B.242 (1) and jointly appointed by the county governing bodies of each county in the region to develop, fund, implement and monitor the achievement of the regional investment plan.

(3) “Regional investment plan” is a long-term economic and community development plan, updated each biennium, that focuses on the economic and community development priorities of each region, including but not limited to:

(a) Supporting communities and populations that have been left out of Oregon's economic expansion and diversification;

(b) Helping companies that are starting up or are already doing business in Oregon to compete globally;

(c) Ensuring that economic strategies reinforce Oregon's long-term prosperity and livability; and

(d) Coordinating efforts of economic and community development, education, workforce development, natural resource management and other civic activities.

(4) “Regional partnership” means a group of regional and economic development partners, including but not limited to cities, counties, ports, Indian tribes, special districts, nonprofit organizations and private organizations, that join together as a regional partnership in a memorandum of understanding between the members of the partnership and the directors of the Department of Transportation, the Economic and Community Development Department, the Housing and Community Services Department, the Department of Land Conservation and Development and the Department of Environmental Quality to provide a forum for coordination of economic and community development planning and investments so that strategies and processes for economic and community development are leveraged to the greatest extent possible to meet agreed-upon priority issues, challenges and goals. [Formerly 285.630; 1999 c.509 s.47]

285B.233 Legislative finding; purpose. (1) The Legislative Assembly finds that regional investment plans are essential to the state's economic and community development goals and that to be effective regional investment plans must have the coordinated support of available resources.

(2) The Legislative Assembly declares that the purpose of ORS 285B.230 to 285B.248 and 285B.269 is:

(a) To encourage the development of regional investment plans that address the economic and community development priorities of each region of the state;

(b) To identify and coordinate regional economic and community development priorities;

(c) To ensure that economic and community development plans reinforce the long-term prosperity and livability of Oregon;

(d) To effectively utilize available resources through a regional investment program; and

(e) To coordinate private and public resources to support economic and community development. [Formerly 285.633; 1999 c.509 s.48]

285B.236 Guidelines for regional investment plans. (1) The Economic and Community Development Department, by rule, shall adopt guidelines for submission of regional investment plans and distribution of funds.

(2) The guidelines shall provide that the regional investment plans are approved in accordance with criteria reflecting the economic and community benefits to the state. Each regional investment plan must at a minimum set forth in measurable terms the extent to which the plan will accomplish the economic and community development priorities of the region.

(3) The department, in collaboration with counties, shall establish regions, based on information and advice received from county governing bodies and on historical, cultural and economic links among counties. A region shall consist of at least two contiguous counties. For any area in which a regional partnership is established, the department may accept the regional boundaries designated by the partnership.

(4) The department shall require each region to examine its economic and community development needs. [Formerly 285.635; 1999 c.509 s.49]

285B.239 Regional investment plan content. Regional investment plans shall serve as a basis for state financial assistance to projects to meet regional economic and community development priorities. Each group of counties that form a region shall submit a regional investment plan that at a minimum shall include the following elements:

(1) An identification of short-term and long-term regional economic and community development priorities;

(2) An analysis of the unique or significant resources that provide the foundation for the regional investment plan;

(3) An analysis of barriers to implementation of the regional investment plan and an identification of the means to overcome those barriers;

(4) A long-term plan to implement the regional investment plan, including necessary actions by:

(a) Local governments;

(b) The private sector;

(c) State government; and

(d) Federal government;

(5) A two-year implementation plan with a prioritized list of projects and activities to be undertaken or funded by the state from lottery proceeds and other sources;

(6) A plan for involvement of disadvantaged and minority groups in the region;

(7) Performance measurements for meeting the objective set forth in ORS 285B.236 (2). Each region shall develop an evaluation plan, as part of its regional investment plan, for measuring and monitoring regional investment plan performance. The evaluation plan shall include regional benchmarks for monitoring achievement of the regional investment plans and priorities. When regional benchmarks are established, interim indicators of performance shall be determined after negotiation between the regional board and the Oregon Economic and Community Development Commission. The regional board shall periodically submit performance reports to the county governing bodies in the region, the Oregon Economic and Community Development Commission, the Governor and the Legislative Assembly; and

(8) An overall strategy management and project implementation plan that demonstrates that a region has the capacity to allocate resources and insures that such resources are effectively used. [Formerly 285.637; 1999 c.509 s.50]

285B.242 Adoption of regional investment plan; regional boards; hearing; review; approval. (1) The governing body of each county of this state shall be responsible for the submission of a regional investment plan as provided in ORS 285B.239. The governing body of a county shall designate a regional board to develop the regional investment plan. The regional board shall consist of individuals who represent various local interests including cities, counties, ports, special districts and Indian tribes and significant representation from the private economic sector. The regional board shall include members who are representatives of rural interests, including local government.

(2) The regional board shall be responsible for developing the regional investment plan for the region.

(3) The regional board shall hold a public hearing in each county in the region prior to a vote by the governing bodies of the counties to recommend to the Governor the regional investment plan described in ORS 285B.239.

(4) In developing the list provided for in ORS 285B.239 (5), a regional board shall consult with industries, cities, ports, special districts, regional workforce committees and federally recognized Oregon Indian tribes located in the region.

(5) A region shall submit the regional investment plan to the Economic and Community Development Department for review by the Oregon Economic and Community Development Commission. The department shall work with regions to refine regional investment plans and ensure compliance with the requirements of ORS 285B.230 to 285B.248 and 285B.269. The Oregon Economic and Community Development Commission shall make recommendations on approval of the plan to the Governor for final approval or shall return the plan to the regional board for further modification.

(6) The Economic and Community Development Department shall be responsible for identifying common issues among regions, developing statewide strategies and organizing opportunities for regions to address them.

(7) After a regional investment plan is developed by a regional board, adopted by the governing bodies of the counties and approved by the Governor, the regional board, in each biennium, shall update the plan and recommend a two-year implementation plan. The implementation plan shall be adopted by the governing bodies of the counties after input from the cities, ports, special districts, Indian tribes, private economic sector and other parties in the region, shall be reviewed by the Oregon Economic and Community Development Commission and must be approved by the Governor before taking effect.

(8) The Governor may delegate responsibility for review and approval of a regional investment plan to a regional partnership. [Formerly 285.640; 1999 c.509 s.51]

285B.245 Governor to adopt investment plan; modification; coordination with other economic development efforts. (1) After considering the recommendations submitted, the Governor may adopt a proposed regional investment plan or return the plan to the affected counties for modification.

(2) The Economic and Community Development Department shall coordinate adopted regional investment plans with existing state and local economic development efforts to support a state strategy for economic development. Regions using regional investment funds for tourism or industrial marketing projects must, as a condition for receiving the funds, demonstrate that the projects complement and are consistent with existing statewide marketing campaigns. The department shall work with regions to ensure coordination among statewide marketing efforts and regional tourism and industrial marketing projects funded through the regional investment program established under ORS 285B.230 to 285B.248 and 285B.269.

(3) The department shall discourage competition among regions for existing Oregon businesses and economic activity. [Formerly 285.643; 1999 c.509 s.52]

285B.248 All counties to be included in region. In carrying out the provisions of ORS 285B.230 to 285B.248 and 285B.269, the Economic and Community Development Department shall work to ensure that all counties are included in a region with an adopted regional investment plan and that each regional investment plan is approved for implementation. [Formerly 285.645; 1999 c.509 s.53]

285B.251 [Formerly 285.647; repealed by 1999 c.509 s.61]

285B.254 Rural Investment Fund. (1) There is created a Rural Investment Fund, separate and distinct from the General Fund, to consist of all moneys credited thereto, including moneys from the Administrative Services Economic Development Fund, and all interest earned on the Rural Investment Fund. The Rural Investment Fund is created to provide a flexible funding source for financing those locally determined programs and projects that may not be eligible for financing through other state and federal funding sources. The moneys in the fund are continuously appropriated to the Economic and Community Development Department to be used to promote economic and community development in rural communities.

(2) The department may use moneys in the Rural Investment Fund to pay for the administrative expenses of operating the economic development programs under ORS 285B.257.

(3) After consulting with regional boards and representatives of rural communities, the department, by rule, shall adopt standards, objectives and criteria for the use and distribution of moneys in the Rural Investment Fund. [Formerly

285.648; 1999 c.509 s.54]

Note: 285B.254 and 285B.257 were enacted into law by the Legislative Assembly but were not added to or made a part of ORS chapter 285B or any series therein by legislative action. See Preface to Oregon Revised Statutes for further explanation.

285B.257 Rural action plans; distribution of Rural Investment Fund to implement plans; biennial reports; prohibited uses of fund. (1) Moneys in the Rural Investment Fund shall be distributed to regional boards designated under ORS 285B.242 for economic development programs and projects designed to benefit rural communities.

(2) Each regional board shall update the regional investment plan prepared under ORS 285B.239 to include a rural action plan consistent with the purpose and objectives of the Rural Investment Fund. A rural action plan must be reviewed by the Oregon Economic and Community Development Commission and approved by the Governor before any moneys from the Rural Investment Fund may be distributed for implementing any program or project described in the rural action plan. Moneys from the Rural Investment Fund shall not be used to retire any debt or pay for expenditures made or expenses incurred prior to the approval of a rural action plan.

(3) In each biennium, a regional board may dedicate a portion of the moneys distributed to the board from the Rural Investment Fund for technical assistance and staff support for updating the rural action plan and for developing programs and projects under the rural action plan. The regional board shall determine the amount of moneys dedicated to such purposes. Notwithstanding subsection (2) of this section, the Economic and Community Development Department may distribute moneys from the Rural Investment Fund for technical assistance and staff support prior to approval of the rural action plan.

(4) In each biennium, each regional board shall submit a report on the expenditure of moneys received under this section and shall indicate the success of the programs and projects financed with moneys from the Rural Investment Fund. The success of programs and projects shall be defined by specific performance measurements developed by the regional board. The report required by this subsection shall be made part of the biennial report submitted to the Governor and the Legislative Assembly under ORS 285B.263.

(5) Moneys from the Rural Investment Fund shall not be used to substitute for local government expenditures for existing and continuing public services. The Economic and Community Development Department shall adopt rules to carry out the provisions of this subsection. [Formerly 285.649; 1999 c.509 s.55]

Note: See note under 285B.254.

285B.260 Regional Investment Fund. (1) There is created a Regional Investment Fund, separate and distinct from the General Fund, to consist of all moneys credited thereto, including moneys from the Administrative Services Economic Development Fund, and all interest earned on the Regional Investment Fund. The fund is continuously appropriated to the Economic and Community Development Department to be used for grants to implement ORS 171.845, 280.518 and 285B.230 to 285B.269.

(2) The department may use moneys in the Regional Investment Fund to pay for the administrative expenses of operating the regional investment program under ORS 285B.230 to 285B.248 and 285B.269.

(3) The fund shall not be used to retire any debt or to reimburse any person or municipality for expenditures made or expenses incurred prior to the adoption of a regional investment plan. [Formerly 285.650; 1999 c.509 s.56]

285B.263 Expenditure of Regional Investment Fund; distribution. (1) In each biennium, the Economic and Community Development Department shall expend moneys from the Regional Investment Fund for:

(a) Technical assistance and staff support for preparation and update of regional investment plans;

(b) Projects and activities implementing an approved regional investment plan and implementing priorities described in the plan; and

(c) Personnel necessary to administer the plans and projects.

(2) In each biennium, the Oregon Economic and Community Development Commission, by rule and in agreement with the Association of Oregon Counties, League of Oregon Cities and Oregon Public Ports Association, may provide funds, either centrally or to regional boards or both, for multiregion projects that implement the approved regional investment plans of two or more regions with common economic and community development priorities. Funding for multiregion projects under this subsection shall be awarded, at the discretion of the commission, according to the quality of the defined projects.

(3) In each biennium, a regional board may dedicate a portion of regional investment funds for technical assistance and staff support for regional investment plan development and refinement and development and administration of regional partnerships. The portion of funds so dedicated shall be determined by the commission. The commission shall provide regional boards with these funds prior to approval of regional investment plans.

(4) In each biennium, a regional board may dedicate a portion of regional investment funds to provide grants or loans to individual private businesses for fixed asset acquisition. Such funds must be used to make grants and loans that are consistent with the regional investment plan and that support the regional priorities included in the regional investment plan. The terms and conditions of grants or loans to be made under this subsection must be contained in the regional investment plan at the time it is submitted for state review.

(5) After a regional investment plan is adopted, the department in each calendar quarter shall provide regional investment funds, less any moneys used for technical assistance and staff support for regional investment plan development, to the region. Moneys received under this subsection shall be used for development of projects based upon an evaluation by the regional board of the merit and readiness of the projects. Projects that receive such financial assistance must be consistent with the priorities of the approved regional investment plan.

(6) In each biennium, each regional board shall submit a report to the Governor and the Legislative Assembly that describes the expenditure of moneys received under this section and indicates the success, as defined by specified performance measurements, of the funded projects in achieving the regional economic and community development priorities described in ORS 285B.236 (2). Future grants to a regional board may be based on the performance of the board. [Formerly 285.651; 1999 c.509 s.57]

Note: 285B.263 was enacted into law by the Legislative Assembly but was not added to or made a part of ORS chapter 285B or any series therein by legislative action. See Preface to Oregon Revised Statutes for further explanation.

285B.266 Strategic Reserve Fund; sources; uses. (1) There is created a Strategic Reserve Fund, separate and distinct from the General Fund, to consist of all moneys credited thereto, including moneys from the Administrative Services Economic Development Fund, and all interest earned on the Strategic Reserve Fund. The fund is continuously appropriated to the Economic and Community Development Department to be used to implement statewide strategies for economic development.

(2) The fund shall not be used to retire any debt or, except upon approval of the Joint Ways and Means Committee or, if the Legislative Assembly is not in session, the Emergency Board, to pay administrative expenses of the department. Expenses that are project related shall not be considered to be administrative expenses of the department.

(3) The department is directed to place particular emphasis on investments that assist communities, businesses or industries in cost-effective projects that assist the creation, expansion and preservation of the principal traded sector industries of Oregon and encourage diversification and preservation of regional economies. The fund shall be used to assist economic and community development projects of public entities, industry groups or businesses with significant long-term, regional or statewide economic impacts, to provide interim financing mechanisms to augment existing public or private sector programs or to analyze statewide, long-term economic issues and opportunities. [Formerly 285.653; 1999 c.509 s.19]

285B.269 Short title. ORS 285B.230 to 285B.248 and 285B.269 shall be known as the Regional Economic Development Act. [Formerly 285.655]

INDUSTRY DEVELOPMENT PROJECTS

285B.280 Definitions for ORS 285B.280 to 285B.286. As used in ORS 285B.280 to 285B.286, unless the context requires otherwise:

(1) “Flexible networks” means groups of three or more private sector firms working cooperatively to manufacture, sell or market products, develop technologies or create or disseminate information.

(2) “High performance manufacturing practices” means methods for organizing work which devolve greater decision-making responsibility onto front-line workers, including but not limited to employee involvement, total quality control, just-in-time production and other related innovations.

(3) “Key industries” means traded sector industries that make a major contribution to the economy of Oregon, including but not limited to, forest products, agricultural products, high technology, primary and fabricated metals,

fisheries, interstate and international tourism, film and video production, graphic communications, biotechnology, software, environmental services, plastics and aerospace.

(4) "Network brokers" means persons who are trained to assist private sector firms to form flexible networks and make other similar efforts to provide for joint manufacturing, marketing, technology development, information dissemination and other activities.

(5) "Traded sector" means industries in which member firms sell their goods or services into markets for which national or international competition exists. [Formerly 285.765]

285B.283 Policy. (1) The Legislative Assembly declares that it is the policy of the State of Oregon, working with private firms, industry associations and others, to encourage cooperative sector-based strategies to promote industrial competitiveness.

(2) The Legislative Assembly declares that it is also the policy of this state that programs to develop particular sectors of this state's economy, to the maximum extent feasible, include firms of all sizes. To promote that policy, the Economic and Community Development Department shall undertake such efforts as are necessary to assure representative participation by small firms under ORS 285B.280 to 285B.286.

(3) The Legislative Assembly further declares that it is the policy of this state to emphasize industry development in those sectors of the economy in which Oregon firms face national and international competition. [Formerly 285.767]

285B.286 Industry development activities. For traded sector industries, the Economic and Community Development Department shall undertake industry development activities which may include, but are not limited to, all of the following:

(1) Focus groups and other meetings and related studies to identify traded sector industry members and issues of common concern within an industry.

(2) State technical and financial support for formation of industry associations, publication of association directories and related efforts to create or expand the activities of industry associations.

(3) Helping establish research consortia.

(4) Joint training and education programs and curricula related to the specific needs of traded sector industries.

(5) Cooperative market development activities.

(6) Analysis of the need, feasibility and cost for establishing product certification and testing facilities and services. [Formerly 285.770; 1999 c.509 s.20]

285B.289 [Formerly 285.773; repealed by 1999 c.509 s.61]

285B.292 [Formerly 285.775; repealed by 1999 c.509 s.61]

285B.295 [Formerly 285.777; repealed by 1999 c.509 s.61]

285B.298 [Formerly 285.780; repealed by 1999 c.509 s.61]

STATE REVENUE BONDS FOR INDUSTRIAL, COMMERCIAL, RESEARCH AND DEVELOPMENT USES

285B.320 Policy. The Legislative Assembly finds that by use of the powers and procedures described in ORS 285B.320 to 285B.377 for the assembling and financing of lands for industrial, commercial and research and development uses and for the construction and financing of facilities for such uses, financed through the issuance of bonds secured solely by the properties, loan payments, rentals or other financing payments thus made available, the state may be able to reduce substantially in various counties the occurrence of economic conditions requiring more expensive remedial action. It is the purpose of ORS 285B.320 to 285B.377 to authorize the exercise of powers granted by ORS 285B.320 to 285B.377 by this state in addition to and not in lieu of any other powers it may possess. [Formerly 285.310; 1999 c.509 s.29]

285B.323 Definitions for ORS 285B.320 to 285B.377. As used in ORS 285B.320 to 285B.377, unless the context requires otherwise:

(1) "Bond" means any evidence of indebtedness, including but not limited to any bond, note, obligation, loan agreement, financing agreement, contracts for leasing, rental or financing of real or personal property, including

contracts for rental, long term leases under an optional contract for purchase, financing agreements with vendors, financial institutions or others or for purchase of any property secured by revenues or from other financing sources as provided in ORS 285B.320 to 285B.377. A bond, as defined in this subsection and issued under ORS 285B.320 to 285B.377, shall be considered a revenue bond for purposes of ORS 286.031.

(2) "Economic development project" includes any properties, real or personal, used or useful in connection with a revenue producing enterprise. "Economic development project" shall not include any facility or facilities designed primarily for the generation, transmission, sale or distribution of electrical energy.

(3) "Eligible project" means an economic development project found by the Oregon Economic and Community Development Commission to meet standards of the commission adopted under ORS 285A.110. The commission may treat as a single eligible project for bonding purposes any number of economic development projects determined to be eligible projects. [Formerly 285.315; 1999 c.509 s.30]

285B.326 Determination of eligibility of projects for financing; fees. (1) Upon determining an economic development project an "eligible project," the Oregon Economic and Community Development Commission shall forward the application to the State Treasurer, who shall determine whether to issue the bonds.

(2) The commission shall collect the fees set forth in subsection (3) of this section from an applicant that seeks to have an economic development project declared eligible for financing. The fee may be collected even though the project has not been determined to be eligible for financing. Moneys collected under this subsection are continuously appropriated to the commission for the purpose of administration or funding of any program it is authorized to operate. Participation fees received on bonds issued pursuant to ORS 285B.377 may be paid to local development groups for administration expenses related to investigating proposed economic development projects and assisting the commission in processing applications pursuant to ORS 285B.377.

(3) The fees described in subsection (2) of this section are as follows:

(a) $250 for an application of not to exceed $500,000.

(b) $500 for an application of more than $500,000.

(c) A closing fee of not to exceed one-half of one percent of the total bond issue for the project, as determined by the commission.

(d) A one-time participation fee, not to exceed one-half of one percent of the total bond issue or an annual participation fee not to exceed one one-sixteenth of one percent of the outstanding principal of the bond issue as determined by the commission.

(e) For bonds issued under ORS 285B.374 and 285B.377, insurance assessments in amounts and payable at such times as are required by rules adopted pursuant to ORS 285A.110. [Formerly 285.320; 1999 c.509 s.31]

285B.329 Review by Oregon Economic and Community Development Commission. The state, acting through the State Treasurer, shall not undertake to finance any economic development project pursuant to ORS 285B.320 to 285B.377 before the Oregon Economic and Community Development Commission has reviewed the project pursuant to standards adopted under ORS 285A.110. [Formerly 285.325; 1999 c.509 s.32]

285B.332 Request by county governing body. (1) The undertaking of any eligible project must be requested by official action of the governing body of the county taken at a regular or duly called special meeting thereof by the affirmative vote of a majority of its members.

(2) The governing body of any Oregon county is encouraged to forward appropriate prospective eligible projects to the Oregon Economic and Community Development Commission for processing pursuant to ORS 285B.326.

(3) For purposes of this section, for projects located on a federally recognized Oregon Indian reservation, the governing body of a county shall be considered to be the governing body of the federally recognized Oregon Indian tribe.

(4) If the governing body is requesting the undertaking of an eligible project under ORS 285B.386, it may impose additional reasonable requirements on the applicant. [Formerly 285.330; 1999 c.509 s.33]

285B.335 Powers of State Treasurer. In addition to any other powers granted by law or by charter, in relation to an eligible project, the state, acting through the State Treasurer or a designee thereof may:

(1) Enter into agreements to finance the costs of an eligible project by loaning or otherwise making available the proceeds of bonds authorized by ORS 285B.374 and 285B.377 to any person, firm or public or private corporation or federal or state governmental subdivision or agency under such terms and with such security as the state may approve;

(2) Lease and sublease eligible projects to any person, firm or public or private corporation or federal or state governmental subdivision or agency in such manner that rents to be charged for the use of such projects shall be established, and revised from time to time as necessary, so as to produce income and revenue sufficient to provide for the prompt payment of principal of and interest on all bonds issued under this section when due, and the lease or financing agreement shall also provide that the lessee, borrower or financing party shall be required to pay all expenses of the operation and maintenance of the project including, but without limitation, adequate insurance thereon and insurance against all liability for injury to persons or property arising from the operation thereof, and all taxes and special assessments levied upon or with respect to the leased premises and payable during the term of the lease, during which term ad valorem taxes in the same amount and to the same extent as though the lessee were the owner of all real and personal property comprising the project;

(3) Pledge and assign to the holders of such bonds or a trustee therefor all or any part of the revenues of one or more eligible projects owned or to be acquired by the state, and define and segregate such revenues or provide for the payment thereof to a trustee;

(4) Mortgage or otherwise encumber eligible projects in favor of the holders of such bonds or in favor of any escrow agent, vendor, lender, other financing party or trustee therefor. However, in creating any such mortgages or encumbrances the state can not obligate itself except with respect to the project;

(5) Make all contracts, execute and deliver all instruments, and do all things necessary or convenient in the exercise of the powers granted by this section, or in the performance of its covenants or duties, or in order to secure the payment of its bonds; including a contract entered into prior to the construction, acquisition and installation of the eligible project authorizing the lessee, borrower or other financing party, subject to such terms and conditions as the state shall find necessary or desirable and proper, to provide for the construction, acquisition and installation of the buildings, improvements and equipment to be included in the project by any means available to the lessee, borrower or other financing party, and in the manner determined by the lessee, borrower or other financing party, and without advertisement for bids as may be required for the construction, acquisition or installation of other public facilities;

(6) Enter into and perform such contracts and agreements with political subdivisions and state agencies as the respective governing bodies of the same may consider proper and feasible for or concerning the planning, construction, installation, lease, or other acquisition, and the financing of such facilities, which contracts and agreements may establish a board, commission or such other body as may be deemed proper for the supervision and general management of the facilities of the eligible project; and

(7) Accept from any authorized agency of the state or federal government loans or grants for the planning, construction, acquisition, leasing, or other provision of any eligible project, and enter into agreements with such agency respecting such loans or grants. [Formerly 285.335; 1999 c.509 s.34]

285B.338 Powers of Oregon Economic and Community Development Commission. In carrying out its duties under ORS 285B.320 to 285B.377, the Oregon Economic and Community Development Commission, acting for and in behalf of the state as its duly authorized agency, may:

(1) Acquire, construct and hold in whole or in part any lands, buildings, easements, water and air rights, improvements to lands and buildings and capital equipment to be located permanently or used exclusively on such lands or in such buildings, which are deemed necessary in connection with an eligible project to be situated within the state, and construct, reconstruct, improve, better and extend such projects, and enter into contracts therefor; and

(2) Sell and convey all properties acquired in connection with eligible projects, including without limitation the sale and conveyance thereof subject to any mortgage and the sale and conveyance thereof under an option granted to the lessee of the eligible project, for such price, and at such time as the state may determine. However, no sale or conveyance of such properties shall ever be made in such manner as to impair the rights of interests of the holder, or holders, or any bonds issued under the authority of ORS 285B.320 to 285B.377. [Formerly 285.340; 1999 c.509 s.35]

285B.341 Limitation on state power. Except as provided in ORS 285B.338 (2), the state shall not have power to operate any eligible project as a business or in any manner whatsoever, and except as provided in ORS 285B.374 and 285B.377, nothing in ORS 285B.320 to 285B.377 authorizes the state to expend any funds on any eligible project, other than the revenues of such projects, or the proceeds of revenue bonds issued hereunder, or other funds granted to the state for the purposes of an eligible project. [Formerly 285.345]

285B.344 Authority to issue bonds. (1) If the State Treasurer determines that bonds should be issued:

(a) The State Treasurer may authorize and issue in the name of the State of Oregon bonds secured by revenues

from eligible economic development projects or from other financing sources, and where applicable, secured as provided in ORS 285B.374 and 285B.377, to finance or refinance in whole or part the cost of acquisition, construction, reconstruction, improvement or extension of projects. The bonds shall be identified by project and issued in the manner prescribed by ORS 286.010, 286.020 and 286.105 to 286.135, and refunding bonds may be issued to refinance such bonds.

(b) The State Treasurer shall designate the underwriter, trustee, bond counsel, vendor, lender or other financing party, if any, and enter into appropriate agreements with each to carry out the provisions of ORS 285B.320 to 285B.377.

(2) Any escrow agent, bond registrar, paying agent or trustee, if any, designated by the State Treasurer to carry out all or part of the powers specified in ORS 285B.335 must agree to furnish financial statements and audit reports for each bond issue. [Formerly 285.350; 1999 c.509 s.36]

285B.347 Issuance of bonds; determining factors. In determining whether to issue bonds under ORS 285B.320 to 285B.377, the State Treasurer shall consider:

(1) The market for the types of bonds proposed for issuance.

(2) The terms and conditions of the proposed issue.

(3) Such other relevant factors as the State Treasurer considers necessary to protect the financial integrity of the state. [Formerly 285.355; 1999 c.509 s.37]

285B.350 Method of issuing bonds. Bonds authorized under ORS 285B.320 to 285B.377 shall be issued in accordance with the provisions of ORS 288.515 to 288.550. [Formerly 285.360]

285B.353 Administration expenses. The administrative expenses of the State Treasurer shall be charged against bond proceeds or project revenues. [Formerly 285.365]

285B.356 Refunding bonds. The State Treasurer shall have the power, whenever the treasurer deems refunding expedient, to refund any bonds by the issuance of new bonds, whether the bonds to be refunded have or have not matured. The refunding bonds may be exchanged for bonds to be refunded and the proceeds applied to the purchase, redemption or payment of such bonds. [Formerly 285.370]

285B.359 Validity of bonds. The validity of bonds issued under ORS 285B.320 to 285B.377 shall not be dependent on nor be affected by the validity or regularity of any proceeding relating to the acquisition, purchase, construction, installation, reconstruction, improvement, betterment or extension of the eligible project for which the bonds are issued. The official action authorizing such bonds may provide that the bonds shall contain a recital that they are issued pursuant to ORS 285B.320 to 285B.377 and such recital shall be conclusive evidence of their validity and of the regularity of their issuance. [Formerly 285.375]

285B.362 Covenants in bonds. The official action authorizing the issuance of bonds under ORS 285B.320 to 285B.377 to finance or refinance in whole or in part, the acquisition, construction, installation, reconstruction, improvement, betterment or extension of any eligible project may contain covenants, notwithstanding that such covenants may limit the exercises of powers conferred by ORS 285B.320 to 285B.377 in the following respects and in such other respects as the state, acting through the State Treasurer, or the designee of the treasurer may decide:

(1) The rents to be charged for the use of properties acquired, constructed, installed, reconstructed, improved, bettered or extended under the authority of ORS 285B.320 to 285B.377;

(2) The use and disposition of the revenues of such projects;

(3) The creation and maintenance of sinking funds and the regulation, use and disposition thereof;

(4) The creation and maintenance of funds to provide for maintaining the eligible project and replacement of properties depreciated, damaged, destroyed or condemned;

(5) The purpose or purposes to which the proceeds of sale of bonds may be applied and the use and disposition of such proceeds;

(6) The nature of mortgages or other encumbrances on the eligible project made in favor of the holder or holders of such bonds or in favor of any escrow agent, vendor, lender, other financing party or trustee therefor;

(7) The events of default and the rights and liabilities arising thereon and the terms and conditions upon which the holders of any bonds may bring any suit or action on such bonds or on any coupons appurtenant thereto;

(8) The issuance of other or additional bonds or instruments payable from or constituting a charge against the revenue of the eligible project;

(9) The insurance to be carried upon the eligible project and the use and disposition of insurance moneys;

(10) The keeping of books of account and the inspection and audit thereof;

(11) The terms and conditions upon which any or all of the bonds shall become or may be declared due before maturity and the terms and conditions upon which such declaration and its consequences may be waived;

(12) The rights, liabilities, powers and duties arising upon the breach by the municipality or redevelopment agency of any covenants, conditions or obligations;

(13) The appointing of and vesting in a trustee or trustees of the right to enforce any covenants made to secure or to pay the bonds; the powers and duties of such trustee or trustees, and the limitation of their liabilities;

(14) The terms and conditions upon which the holder or holders of the bonds, or the holders of any proportion or percentage of them, may enforce any covenants made under ORS 285B.320 to 285B.377;

(15) A procedure by which the terms of any official action authorizing bonds or of any other contract with bondholders, including but not limited to an indenture of trust or similar instrument, may be amended or abrogated, and the amount of bonds the holders of which may consent thereto, and the manner in which such consent may be given; and

(16) The subordination of the security of any bonds issued under ORS 285B.320 to 285B.377 and the payment of principal and interest thereof, to the extent deemed feasible and desirable by the state, to other bonds or obligations of the state issued to finance the eligible project or that may be outstanding when the bonds thus subordinated are issued and delivered. [Formerly 285.380; 1999 c.509 s.38]

285B.365 Limitations of bonds; recitals. (1) Revenue bonds issued under ORS 285B.320 to 285B.377:

(a) Shall not be payable from nor charged upon any funds other than the revenue pledged to the payment thereof, except as provided in this section and ORS 285B.374 and 285B.377, nor shall the state be subject to any liability thereon. No holder or holders of such bonds shall ever have the right to compel any exercise of the taxing power of the state to pay any such bonds or the interest thereon, nor to enforce payment thereof against any property of the state except those projects or portions thereof, mortgaged or otherwise encumbered under the provisions and for the purposes of ORS 285B.320 to 285B.377.

(b) Shall not constitute a charge, lien or encumbrance, legal or equitable, upon any property of the state, except those eligible projects, or portions thereof, mortgaged or otherwise encumbered, under the provisions and for the purposes of ORS 285B.320 to 285B.377 and except as provided in ORS 285B.374 and 285B.377.

(2) Each bond issued under ORS 285B.320 to 285B.377 shall recite in substance that the bond, including interest thereon, is payable solely from the revenue pledged to the payment thereof and as provided in ORS 285B.374 and 285B.377. No such bond shall constitute a debt of the state or a lending of the credit of the state within the meaning of any constitutional or statutory limitation. However, nothing in ORS 285B.320 to 285B.377 is intended to impair the rights of holders of bonds to enforce covenants made for the security thereof as provided in ORS 285B.368. [Formerly 285.385]

285B.368 Powers and rights of bondholders. Subject to any contractual limitation binding upon the holders of any issue of bonds, or any escrow agent, vendor, lender, other financing party or trustee therefor, including but not limited to the restriction of the exercise of any remedy to a specified proportion or percentage of such holders, any holder of bonds, or any trustee therefor, for the equal benefit and protection of all bondholders similarly situated, may:

(1) By action or proceeding for legal or equitable remedies, enforce their rights against the state and any of its officers, agents and employees, and may require and compel the state or any such officers, agents or employees to perform and carry out its and their duties and obligations under ORS 285B.320 to 285B.377 and its and their covenants and agreements with bondholders;

(2) By action require the state to account as if it was the trustee of an express trust;

(3) By action enjoin any acts or things which may be unlawful or in violation of the right of the bondholders;

(4) Bring action upon the bonds;

(5) Foreclose any mortgage or lien given under the authority of ORS 285B.320 to 285B.377 and cause the property standing as security to be sold under any proceedings permitted by law or equity; and

(6) Exercise any right or remedy conferred by ORS 285B.320 to 285B.377 without exhausting and without regard to any other right or remedy conferred by ORS 285B.320 to 285B.377 or any other law of this state, none of which rights and remedies is intended to be exclusive of any other, and each is cumulative and in addition to every other

right and remedy. [Formerly 285.390; 1999 c.509 s.39]

285B.371 Loans to eligible projects when state holds no interest. The state, acting through the State Treasurer and the Oregon Economic and Community Development Commission, or either of them, may loan the proceeds of the bonds authorized by ORS 285B.320 to 285B.377 for eligible projects without the necessity of the state having any ownership or leasehold interest in the eligible projects. Loans made pursuant to this section shall be secured, if at all, to the extent deemed necessary or desirable by the State Treasurer and the Oregon Economic and Community Development Commission. [Formerly 285.393; 1999 c.509 s.40]

285B.374 Oregon Economic and Community Development Fund; uses; sources; Economic Development Insurance Account. (1) There is created within the State Treasury a revolving trust fund known as the Oregon Economic and Community Development Fund, separate and distinct from the General Fund. Interest earned by the fund shall be credited to the fund. Moneys in this fund shall be used in accordance with agreements made by the state, acting through the State Treasurer or the State Treasurer's designee, for the benefit of the holders of bonds issued under ORS 285B.377, but only to pay:

(a) Principal of, interest and redemption premium, if any, on bonds issued under ORS 285B.377;

(b) Insurance premiums for bonds issued under ORS 285B.377; and

(c) Repayment of any transfers authorized by subsection (4) of this section.

(2) The following moneys shall be credited to the Oregon Economic and Community Development Fund:

(a) Reserve funds established for bonds issued under ORS 285B.377.

(b) Such moneys as may be appropriated to the fund by the Legislative Assembly.

(c) Payments made in respect of eligible projects under loan agreements, financing agreements, notes, obligations, indentures, leases or subleases that are dedicated to payments of bond principal, interest and redemption premium, if any.

(d) Earnings from investment of moneys in the fund.

(e) Any grant made to the fund by any federal agency.

(f) Any other moneys required to be placed in the fund pursuant to any agreement authorized by ORS 271.510, 271.520, 285B.092, 285B.320 to 285B.326, 285B.335, 285B.341, 285B.344, 285B.350, 285B.365, 285B.371 to 285B.377 and 777.250.

(3) There is created a trust account within the Oregon Economic and Community Development Fund to be known as the Economic Development Insurance Account. Fees authorized under ORS 285B.326 (3)(e) and other moneys required to be placed in the account pursuant to any agreement authorized by ORS 271.510, 271.520, 285B.092, 285B.320 to 285B.326, 285B.335, 285B.341, 285B.344, 285B.350, 285B.365, 285B.371 to 285B.377 and 777.250 and such other assets as may be required pursuant to ORS 285B.377 (4) and earnings in the account shall be credited to the Economic Development Insurance Account. Fees authorized under ORS 285B.326 (3)(d) shall be credited to the Economic Development Insurance Account, unless otherwise required as repayment for transfers provided for in subsection (4)(b) of this section. Moneys in the Economic Development Insurance Account shall be used only to replenish reserves established in the Oregon Economic and Community Development Fund or to pay principal and interest due on bonds authorized under ORS 285B.377 and to pay insurance premiums for such bonds, in accordance with rules adopted by the state, acting through the State Treasurer or the State Treasurer's designee.

(4) If, at any time, there are insufficient moneys in the Oregon Economic and Community Development Fund available for timely payment of the bonds authorized by ORS 285B.377, then the conditions precedent to a transfer of moneys under ORS 293.210 from the Oregon Business Development Fund to the Oregon Economic and Community Development Fund shall be deemed to be met for:

(a) A transfer of any liquid assets in the Oregon Business Development Fund which are not then required to meet obligations against that fund; and

(b) A maximum transfer of $3 million from any other state funds having excess money, but only under terms for repayment which are approved by the State Treasurer. [Formerly 285.395; 1999 c.509 s.41]

285B.377 Issuance of bonds secured by Oregon Economic and Community Development Fund. (1) In addition to bonds authorized by ORS 285B.320 to 285B.377, the state may issue bonds to finance eligible projects which are secured in part by the assets of the Oregon Economic and Community Development Fund, as provided in this section.

(2) The aggregate principal amount of bonds issued pursuant to this section which are outstanding at any time shall not exceed $20 million.

(3) Bonds issued pursuant to this section shall be secured in the manner provided in rules adopted by the Oregon Economic and Community Development Commission and approved by the State Treasurer.

(4) The commission may require participants to agree to such arrangements as it and the State Treasurer deem necessary to secure the payment of the principal of, and interest on, the bonds, and redemption premium, if any. Such arrangements may include, but are not limited to, establishment of a debt service reserve, creation of a self-insurance program, the purchase of insurance or other similar devises ensuring the payment of the principal of, and interest on, the bonds issued pursuant to this section.

(5) Within 30 days following the closing of each fiscal quarter, the commission shall report on its operations to the Governor, State Treasurer and the Legislative Assembly. The report shall include a summary of the activities of the commission relating to bonds issued under this section.

(6) Notwithstanding the provisions of ORS 285B.365, the state may pledge to the payment of bonds authorized by this section any funds or revenues specifically set forth in this section, as well as any other funds or revenues which may be used for such purposes under any other provision of state law.

(7) Except to the extent they are inconsistent with the provisions of this section or the rules adopted under ORS 271.510, 271.520, 285B.092, 285B.320 to 285B.326, 285B.335, 285B.341, 285B.344, 285B.350, 285B.365, 285B.371 to 285B.377 and 777.250, the provisions of ORS 285B.320 to 285B.377 apply to the bonds issued under ORS 271.510, 271.520, 285B.092, 285B.320 to 285B.326, 285B.335, 285B.341, 285B.344, 285B.350, 285B.365, 285B.371 to 285B.377 and 777.250 and the loans made pursuant to this section. [Formerly 285.397; 1999 c.509 s.42]

285B.380 Definitions for ORS 285B.383 to 285B.392 and 307.110. As used in ORS 285B.383, 285B.386, 285B.389, 285B.392 and 307.110, unless the context requires otherwise, "eligible project" has the meaning given that term in ORS 285B.323. [Formerly 285.398]

285B.383 Determination of projects for financing; first-source hiring agreements; invested cost of project. (1) If an eligible project directly benefits a traded sector industry, as defined in ORS 285B.280 (3), and if the total cost of the eligible project exceeds $100 million, the State of Oregon, acting through the Oregon Economic and Community Development Commission, may determine that the real and personal property constituting the eligible project is eligible for the tax exemption provided in ORS 307.123, and the State of Oregon, acting through the State Treasurer, may authorize and issue revenue bonds in accordance with ORS 285B.320 to 285B.377 to finance the costs of the eligible project.

(2) Nothing in this section authorizes the Oregon Economic and Community Development Commission to determine that an existing eligible project is eligible for the tax exemption provided in ORS 307.123.

(3) A business firm that will be benefited by an eligible project shall enter into a first-source hiring agreement with a publicly funded job training provider that will remain in effect until the end of the tax exemption period.

(4) If an eligible project is leased or subleased to any person, the lessee shall be required to pay property taxes levied upon or with respect to the leased premises only in accordance with ORS 307.123.

(5) For purposes of determining the assessment and taxation of the eligible project in ORS 307.123 and the calculation of the community services fee in ORS 285B.386 (4)(b), in addition to the requirements set out in ORS 285B.323 (3), the invested cost of all real and personal property to be included in the eligible project shall be established by the Oregon Economic and Community Development Commission when it determines that the project is an eligible project. [Formerly 285.399; 1999 c.509 s.26]

285B.386 Request by county governing body; approval of tax exemption; community services fee. (1) The undertaking of any eligible project must be requested by official action of the governing body of the county taken at a regular or duly called special meeting thereof by the affirmative vote of a majority of its members.

(2) The governing body of any Oregon county is encouraged to forward appropriate prospective eligible projects to the Economic and Community Development Department for processing.

(3) For purposes of this section, for projects located on a federally recognized Oregon Indian reservation, the governing body of a county shall be considered to be the governing body of the federally recognized Oregon Indian tribe.

(4) The county shall not request an eligible project to be determined to be eligible for a tax exemption under ORS 307.123 unless, after a public hearing:

(a) The county and, if the proposed eligible project will be located within a city, the city have approved the special provisions related to the property tax exemption.

(b) As consideration for the county requesting determination that the eligible project is eligible for a property tax exemption under ORS 307.123, the business firm that will be benefited by the eligible project enters into an agreement with the county for payment to the county of an annual fee for community services support in an amount equal to 25 percent of the property taxes exempted in each assessment year, but not exceeding $2 million in any year. The fee shall be paid annually during the tax exemption period. For purposes of this paragraph, the property tax exempted in a year shall be calculated as the effective tax rate after any constitutional limits on the taxable portion of the value of the project multiplied by the assessed value of the exempt portion of the project.

(c) The applicant has reached agreement with the county on any other requirements related to the project. The agreement shall include provisions for the date of payment of the fee required under paragraph (b) of this subsection, for refunding or crediting overpayments, for interest on late payments or underpayments and for the manner in which an appeal of the assessed value of the property included in the project will affect the payment of the fee.

(5) The fee collected under subsection (4)(b) of this section shall be distributed by the county based on an agreement entered into at the time of application between the county and the city, if any, in which the eligible project is located. [Formerly 285.400]

285B.389 Application fees; amount; disposition of fees. (1) The Oregon Economic and Community Development Commission shall collect the fees set forth in subsection (2) of this section from an applicant that seeks to have the real and personal property constituting the eligible project declared eligible for the tax exemption provided in ORS 307.123. The fee may be collected even though the project has not been determined to be eligible for the tax exemption.

(2) The fees described in subsection (1) of this section are as follows:

(a) $10,000 upon application to the commission; and

(b) $50,000 when the eligible project is determined by the commission to be eligible for the tax exemption provided in ORS 307.123. The commission shall pay 50 percent of this fee to the Department of Revenue for the purpose of administration of ORS 307.123.

(3) The fees collected under subsection (2) of this section shall be deposited in the Financial Programs Account created by ORS 285A.212. [Formerly 285.401; 1999 c.509 s.21]

Note: 285A.212 was repealed by section 61, chapter 509, Oregon Laws 1999. The text of 285B.389 was not amended by enactment of the Legislative Assembly to reflect the repeal. Editorial adjustment of 285B.389 for the repeal of 285A.212 has not been made.

285B.392 Confidentiality of project information. Notwithstanding ORS 192.410 to 192.505, the identity of an applicant for an eligible project designation under ORS 285B.383, the application form submitted to the county governing body and the Oregon Economic and Community Development Commission and the negotiations conducted between the applicant and the county shall be confidential, until the county governing body gives notice of its intent to take official action on the application. [Formerly 285.402]

INFRASTRUCTURE PROJECTS

(Generally)

285B.410 Definitions for ORS 285B.410 to 285B.479. As used in ORS 285B.410 to 285B.479, unless the context requires otherwise:

(1) "Municipality" means a city, a county, a port incorporated under ORS 777.010 and 777.050, the Port of Portland created by ORS 778.010, a metropolitan service district organized under ORS chapter 268, a domestic water supply district organized under ORS chapter 264, a water authority or sanitary authority organized under ORS 450.600 to 450.989, a water improvement district organized under ORS chapter 552, a water control district organized under ORS chapter 553, a sanitary district organized under ORS 450.005 to 450.245, a county service district organized under ORS chapter 451 or a tribal council of an Indian tribe in this state.

(2) "Infrastructure project" means:

(a) A project for the construction of sewage treatment works, solid waste disposal sites, water supply works, roads, public transportation, railroad industrial spurs or sidings or other facilities that comprise the physical foundation for industrial and commercial activity. The costs of property acquisition directly related to the infrastructure project and

acquisition of easements or rights of way necessary to accomplish construction of the infrastructure project are eligible for assistance under ORS 285B.410 to 285B.479. The costs of activities related to performing an environmental evaluation of a brownfield are eligible for assistance under ORS 285B.416 (2) and 285B.455 (5). Purchases of off-site property for project-related purposes such as wetland mitigation or other uses not directly related to the infrastructure are not eligible for assistance. As used in this paragraph, "brownfield" and "environmental evaluation" have the meanings given those terms respectively in ORS 285A.185 and 285A.188.

(b) A project, in consultation with the Department of Transportation and other affected agencies, for the acquisition, reconstruction or rehabilitation of an abandoned railroad line or railroad line that has been designated by the owner and operator thereof as subject to abandonment within a three-year period pursuant to federal law and regulations governing abandonment of common carrier railroad lines. The project may include operation or maintenance costs if the project also includes acquisition, reconstruction or rehabilitation.

(c) A safe drinking water project, in consultation with the Water Resources Department, the Health Division of the Department of Human Services or the Department of Land Conservation and Development, for improving a drinking water system for the purpose of achieving or maintaining compliance with applicable state or federal drinking water quality regulations.

(d) A project for the acquisition, construction or development of community facilities, including the acquisition of land, the construction, acquisition, renovation or reconstruction of buildings, structures and other real property and the acquisition or construction of related equipment and fixtures. "Community facilities" includes facilities that are owned by a municipality and are operated by either the municipality or a person under a management contract or operating agreement with the municipality.

(3) "Public transportation" includes public depots, public parking, public docks, public wharves, railroads and airport facilities.

(4) "Roads" includes:

(a) Ways described as streets, highways, throughways or alleys;

(b) Road related structures that are in the right of way such as tunnels, culverts or similar structures; and

(c) Structures that provide for continuity of the right of way such as bridges.

(5) "Sewage treatment works" includes all facilities necessary for collecting, pumping, treating and disposing of sanitary or storm sewage.

(6) "Solid waste disposal site" has the meaning given to the term "disposal site" by ORS 459.005.

(7) "Water supply works" includes all facilities necessary for tapping natural sources of domestic and industrial water, treating and protecting the quality of the water and transmitting it to the point of sale to any public or private agency for domestic, municipal and industrial water supply service.

(8) "Urban infrastructure projects" includes all those projects located in whole or in part within the acknowledged Portland Metropolitan Area Regional Urban Growth Boundary, and the acknowledged urban growth boundaries of the cities of Eugene, Springfield, Salem, Keizer or Medford or projects that will principally benefit these areas. The Director of the Economic and Community Development Department is authorized to resolve situations left in question by this definition.

(9) "Nonurban infrastructure projects" includes all those projects which do not meet the definition of urban infrastructure projects. [Formerly 285.700; 1999 c.509 s.43]

285B.413 Legislative findings. (1) The Legislative Assembly finds that:

(a) The improvement, expansion and new construction of the state's sewage treatment works, water supply works, roads and public transportation provides the basic framework for continuing and expanding economic activity in this state, thereby providing jobs and economic opportunity for the people of Oregon.

(b) It is essential to maintain usable and developable industrial and commercial lands in Oregon.

(2) Since municipalities in this state often suffer from a lack of available financing for such projects, it is the purpose of ORS 285B.410 to 285B.479 to provide financial assistance in order that they may construct, improve and repair those facilities that are essential for supporting continuing and expanded economic activity. It is the intent of the Legislative Assembly, by providing that assistance, to stimulate industrial growth and commercial enterprise and to promote employment opportunities in Oregon.

(3) The money in the Special Public Works Fund shall be used primarily to provide loans to municipalities for infrastructure projects. Grants shall be given only when loans are not feasible due to the economic need of the applicant municipality and special circumstances of the project. The Director of the Economic and Community Development Department is authorized to determine the level of grant or loan funding, if any, on a case-by-case basis.

[Formerly 285.703]

285B.416 Allowable project costs. (1) For purposes of ORS 285B.410 to 285B.479, the total project costs of an infrastructure project may include costs for preliminary planning or legal, fiscal and economic investigations, reports and studies to determine the economic and engineering feasibility of the project. Such planning costs may be paid for with a loan or grant from the Special Public Works Fund, by technical assistance grants or loans awarded to eligible municipalities, or by a municipality itself.

(2) The engineering and architectural reports, studies, surveys, designs, plans, working drawings and specifications necessary in the construction of the infrastructure project shall be eligible for financial assistance under ORS 285B.410 to 285B.479. Proposals for technical assistance grants shall be processed under ORS 285B.419, 285B.428 (2)(a), 285B.437 (2) and 285B.440 (2) in the same manner as other project proposals. [Formerly 285.705]

285B.419 Criteria for project priority; administration by department. (1) The Economic and Community Development Department shall adopt rules and policies for the administration of the Special Public Works Fund. Insofar as practicable, the department's rules shall provide that infrastructure projects that meet the following criteria receive priority for financial assistance:

(a) Provide for the establishment or enlargement of economically viable industries, with reasonable long term growth prospects, including opportunities for innovative new industries or for continuance of existing basic industries.

(b) Result in a net benefit to the state in the long term and not require continuing state subsidies.

(c) Utilize existing public and private assets, including infrastructure, human resources and plant and equipment.

(d) Improve the conditions of the economically disadvantaged and increase the number of jobs that increase average incomes.

(e) Support the development of businesses owned by women and members of minority groups.

(f) Harness Oregon's comparative advantage with emphasis on the growth and development of existing, in-state businesses, especially small businesses.

(g) Direct assistance to projects that assist businesses selling goods and services in markets for which national or international competition exists and prohibit assistance to infrastructure projects that primarily focus on relocating business or economic activity from one part of the state to another.

(h) Result in the economic revitalization of communities.

(i) Are funded and otherwise supported to the maximum extent possible by private resources.

(j) Result in business growth or expansion which would not occur in Oregon without an investment from the Special Public Works Fund.

(2)(a) The Economic and Community Development Department shall manage the Special Public Works Fund and any expenditures from its accounts and transfers between its accounts so that the fund value shall be equal to at least 50 percent of lottery revenues actually transferred to the fund plus interest on such amounts compounded annually at five percent. The fund value shall be determined by summing the cash reserves and the outstanding principal amount of loans to municipalities. Any principal amounts of loans forgiven shall be subtracted from the value of the fund. The value of the fund shall include moneys in the fund that are pledged to the repayment of state bonds.

(b) The department shall quarterly certify the value of the fund to the State Treasurer.

(c) If necessary to insure repayment of bonds issued under ORS 285B.410 to 285B.479, the Economic and Community Development Department is authorized to reduce the value of the fund to less than the limit provided in paragraph (a) of this subsection if the department:

(A) Finds that without such a reduction in fund value, bonds secured by the fund are likely to be in default; and

(B) Imposes a moratorium on grants until the requirements of paragraph (a) of this subsection are met.

(3) Not more than 100 percent of the total cost of any infrastructure project shall be financed from the Special Public Works Fund.

(4) The department may commit moneys in the Special Public Works Fund or reserve future income to the fund for disbursal in future years under ORS 285B.440 (4). The department shall commit or reserve moneys under this subsection only after:

(a) Allowing for contingencies;

(b) Finding that there will be sufficient unobligated net income to the fund to make such future payments. Such a finding shall be based on financial plans which are consistent with the financial requirements of subsections (2) and (4) of this section; and

(c) Providing in any contract for such commitment that the liability of the state to make such annual payments shall

be contingent on the availability of moneys in the Special Public Works Fund.

(5) In assisting local governments with infrastructure projects, the department shall cooperate to the maximum extent possible with other state agencies financing infrastructure projects, including but not limited to the Department of Environmental Quality, the Water Resources Department and the Department of Transportation.

(6) The department shall notify the Housing and Community Services Department of any proposed Special Public Works Fund project with a related workforce increase at the time the department receives the completed application for the project. [Formerly 285.707; 1999 c.509 s.22]

(Community Facilities Projects)

285B.422 Funding of community facilities projects; criteria for project funding; source of assistance limited; application of other laws. (1) The Economic and Community Development Department may provide financial assistance to municipalities for infrastructure projects that are community facilities projects as described in ORS 285B.410 (2)(d).

(2) Before providing financial assistance for a community facilities project, the Economic and Community Development Department must find that:

(a) The municipality has demonstrated that the community facilities project will provide long term benefits to the municipality;

(b) The community facilities project will benefit a broad cross-section of the municipality;

(c) There is a substantial local commitment to the community facilities to be financed; and

(d) There is a need for the proposed community facilities project, and the municipality's financial resources are adequate to provide the working capital needed to ensure success of the project.

(3) Notwithstanding any other provision of ORS 285B.410 to 285B.479, community facilities projects shall be eligible only for loans made with moneys derived from the sale of revenue bonds issued under ORS 285B.467 or for loans made from the Special Public Works Fund. No grants shall be made from the Special Public Works Fund for the costs of a community facilities project. Loans or grants from the Special Public Works Fund and loans from the proceeds of revenue bonds issued under ORS 285B.467 may be used to pay issuance costs and for the funding of any debt service reserve for any revenue bonds issued under ORS 285B.467 to finance community facilities.

(4) ORS 285B.413 (1) and (2), 285B.419 (1), 285B.434 (2), (4) and (5), 285B.464 and 285B.467 (2) and (8) do not apply to a municipality applying for financial assistance for a community facilities project. [1997 c.800 s.12; 1999 c.509 s.44]

Note: 285B.422 and 285B.425 were added to and made a part of 285B.410 to 285B.479 by legislative action but were not added to any smaller series therein. See Preface to Oregon Revised Statutes for further explanation.

285B.425 Community Facilities Account; purpose; sources; use. (1) There is established within the Special Public Works Fund an account to be known as the Community Facilities Account. All moneys in the Community Facilities Account are continuously appropriated to the Economic and Community Development Department for the purpose of providing financial assistance to municipalities for community facilities projects.

(2) The Community Facilities Account shall consist of:

(a) Moneys appropriated to the Community Facilities Account by the Legislative Assembly.

(b) Moneys transferred to the Community Facilities Account from the federal government, other state agencies or local governments.

(c) Repayment of financial assistance provided to municipalities.

(d) Earnings on moneys in the Community Facilities Account.

(e) Any gifts or donations made to the State of Oregon for deposit in the Community Facilities Account.

(3) Moneys in the Community Facilities Account shall be used to provide financial assistance to municipalities for community facilities projects by means of loans, the purchase of the bonds or other obligations of municipalities or the guaranty of all or any portion of the obligations of a municipality that are issued to finance a community facilities project. [1997 c.800 s.13]

Note: See note under 285B.422.

(Financial Assistance for Projects)

285B.428 Application for funds. (1) Any municipality may file an application with the Economic and Community Development Department to obtain financial assistance from the Special Public Works Fund. The application shall be filed in such manner and contain or be accompanied by such information as the department may require.

(2) In addition to other requirements prescribed by the department, an application filed under this section shall:

(a) Describe the nature and purposes of the proposed infrastructure project, including the need for the project and the reasons why the project is in the public interest.

(b) Set forth or be accompanied by a feasibility study of the proposed infrastructure project and an estimate of the costs of construction.

(c) State whether any moneys other than those in the Special Public Works Fund are proposed to be used for the infrastructure project and whether any other moneys are available or have been sought for the project. [Formerly 285.710]

285B.431 Review of feasibility study. Upon receipt of an application filed as provided in ORS 285B.428, the Economic and Community Development Department shall determine whether the feasibility study set forth in or accompanying the application is satisfactory, and if the department determines that it is not satisfactory it may:

(1) Reject the application;

(2) Require the municipality to submit additional information as may be necessary; or

(3) Make, with the agreement of the municipality, such revisions of the feasibility study as it considers necessary to make the plans for the proposed project satisfactory. [Formerly 285.713]

285B.434 Application approval. The Economic and Community Development Department shall not approve financial assistance from the Special Public Works Fund for an infrastructure project proposed in an application filed under ORS 285B.428 unless, after investigation, the department finds that:

(1) The proposed infrastructure project is feasible, and the municipality has certified to the department that there will be adequate funds available to repay any loans made to the municipality under ORS 285B.410 to 285B.479;

(2) The proposed infrastructure project is situated in an area in which economic development is prevented or substantially restricted by a lack of adequate sewage treatment works, solid waste disposal sites, water supply works, roads, public transportation or other facilities that comprise the physical foundation for industrial and commercial activity;

(3) The proposed infrastructure project is situated in a city or county with a comprehensive land use plan that allows industrial and commercial development of a type and scale that is sufficient to repay the costs of the project;

(4) A high probability exists for industrial or commercial development, or both, of the properties served by the infrastructure project;

(5) The municipality has provided as part of the security for repayment of loans or bonds made available through ORS 285B.410 to 285B.479, provisions for payments from any owners of property specially benefited by the infrastructure project which are sufficient when considered with other security to assure repayment of bonds and loans made available through ORS 285B.410 to 285B.479;

(6) Moneys in the appropriate accounts of the Special Public Works Fund are or will be available for the infrastructure project;

(7) The municipality is willing and able to enter into a contract with the department for repayment as provided in ORS 285B.437 (1)(a) to (e); and

(8) The proposed infrastructure project is consistent with rules adopted under ORS 285B.419. [Formerly 285.715]

285B.437 Contract with municipality. (1) If the Economic and Community Development Department approves financial assistance from the Special Public Works Fund for an infrastructure project, the department, on behalf of the state, and the municipality may enter into a contract, which shall set forth, among other matters:

(a) An estimate of the reasonable cost of the infrastructure project.

(b) An agreement by the municipality to proceed expeditiously with, and complete, the project in accordance with plans reviewed and approved by the department.

(c) None of the financial assistance provided by the state shall be used for administrative purposes by the municipality.

(d) A statement that the liability of the state under the contract is contingent upon the availability of moneys in the Special Public Works Fund for use in the infrastructure project.

(e) Such other provisions as the department considers necessary to insure expenditure of the moneys for the purposes set forth in the approved application.

(2) When the department approves financial assistance under ORS 285B.410 to 285B.479 for an infrastructure project, the department shall pay moneys for the project from the Special Public Works Fund in accordance with the terms of the contract.

(3) The department shall determine and approve a maximum amount of a loan for an infrastructure project under ORS 285B.410 to 285B.479 based upon a reasonable and prudent expectation of the municipality's ability to repay any amount borrowed. [Formerly 285.717]

285B.440 Maximum amounts of grants; standards. (1) The maximum amount of any grant to a municipality made from the Special Public Works Fund under ORS 285B.419 shall not exceed $1 million.

(2) No grant to a municipality shall be made for a project in an amount that exceeds 85 percent of total project costs.

(3) The Economic and Community Development Department shall develop standards for determining the maximum proportion of any project which can be funded by grants. Such standards shall at a minimum provide grants equaling a larger percentage of total project costs for projects with greatest economic need.

(4) A grant contract under ORS 285B.437 (1)(a) to (e) and this section may provide for grants on behalf of the municipality on an annual basis in the form of partial repayment to bondholders of amounts owed them. In such cases, the contract shall provide that moneys are or will be available in the Special Public Works Fund for such annual payments. [Formerly 285.720]

285B.443 Conditions for loans or purchase of municipal bonds. (1) Any contract under ORS 285B.437 (1)(a) to (e) that includes provisions for a loan of state moneys to a municipality or the purchase of a bond of a municipality by the state shall include a plan for repayment by the municipality of moneys borrowed from the Special Public Works Fund for an infrastructure project and interest on those moneys at a rate specified in the contract. The repayment plan:

(a) Shall provide for such evidence of debt assurance of, and security for, repayment by the municipality as is considered necessary by the Economic and Community Development Department.

(b) Shall set forth the allocation of special assessments or contractual responsibility among the owners of benefited properties for repayment to the municipality of the amount of the loan.

(c) Shall provide for repayment during a period which shall not exceed the usable life of the proposed project or 25 years, whichever is less.

(2) Notwithstanding any other provision of law, or any restriction on indebtedness contained in a charter, a municipality may borrow from the Special Public Works Fund by entering into a loan contract with the Economic and Community Development Department. The contract may be payable:

(a) From the revenues of any infrastructure project, including special assessment revenues;

(b) From amounts withheld under ORS 285B.449 (1);

(c) From the general fund of the municipality;

(d) From any combination of paragraph (a), (b) or (c) of this subsection; or

(e) From any other sources.

(3) The loan contracts under subsection (2) of this section shall be authorized by an ordinance which is adopted with not less than 14 days' prior notice. Notice shall be published at least once in a newspaper of general circulation within the municipality. [Formerly 285.723]

285B.446 Guaranty of municipal obligations; status of guaranty. (1) The Economic and Community Development Department may enter into contracts to guaranty all or any portion of the obligations of a municipality which are issued to finance an infrastructure project and are not sold to the State of Oregon.

(2) Notwithstanding subsection (1) of this section, guaranty contracts shall be payable solely from money in the Special Public Works Fund, and shall not constitute a debt or obligation of the State of Oregon. The department may, on behalf of the state, establish a special account in the fund, and commit to deposit into the account, specified portions of existing and future allocations to the fund. Such commitments shall be made by rule of the department and shall constitute covenants of the state for the benefit of the owners of obligations guaranteed by the state pursuant to this section. [Formerly 285.725]

285B.449 Effect of failure to comply or default. (1) If a municipality fails to comply with a contract entered into

under ORS 285B.410 to 285B.479, the Economic and Community Development Department may seek appropriate legal remedies to secure any repayment due the Special Public Works Fund. If any municipality defaults on payments due to the Special Public Works Fund under ORS 285B.410 to 285B.479, the State of Oregon may withhold any amounts otherwise due to the municipality to apply to the indebtedness. The department may waive this right to withhold.

(2) Moneys withheld under subsection (1) of this section shall be deposited in the Special Public Works Fund and shall be used to repay any account in the fund from which funds were expended to pay obligations upon which the municipality defaulted. [Formerly 285.727]

285B.452 Other forms of financial assistance. In addition to making loans to municipalities for infrastructure projects and purchasing debt obligations issued to finance an infrastructure project, the Economic and Community Development Department may provide any other form of financial assistance that the department may consider appropriate for the financing of infrastructure projects. [Formerly 285.730]

285B.455 Special Public Works Fund; uses. (1) There is created the Special Public Works Fund, separate and distinct from the General Fund. All moneys credited to the Special Public Works Fund are appropriated continuously and shall be used for the purposes outlined in ORS 285B.410 to 285B.479. There shall be credited to the Special Public Works Fund, money appropriated to the fund by the Legislative Assembly, earnings on the fund, repayment of financial assistance and bond proceeds as authorized under ORS 285B.410 to 285B.479.

(2) Moneys in the Special Public Works Fund, with the approval of the State Treasurer, may be invested as provided by ORS 293.701 to 293.820 and the earnings from such investments shall be credited to the account in the Special Public Works Fund designated by the Economic and Community Development Department.

(3) The Economic and Community Development Department shall be the agency for the State of Oregon for the administration of the Special Public Works Fund.

(4) The department may establish such other accounts within the Special Public Works Fund for the payment of project costs, reserves, debt service payments, credit enhancement, administration and operation expenses or any other purpose necessary to carry out ORS 285B.410 to 285B.479.

(5) Out of moneys in the Special Public Works Fund, the department may make technical assistance grants and loans to municipalities of less than 5,000 residents. A technical assistance grant shall not exceed $10,000. A technical assistance loan shall not exceed $20,000. No more than $250,000 or one percent of the value of the fund, whichever is less, shall be expended on technical assistance grants and loans in any biennium. [Formerly 285.733]

285B.458 Funding of urban and nonurban infrastructure projects. Not less than 33 percent of the funds disbursed from the fund shall be used to provide financial assistance to nonurban infrastructure projects and not less than 33 percent shall be used to provide financial assistance to urban infrastructure projects. [Formerly 285.735]

285B.461 Limit on use of moneys in fund for administrative expenses. Out of the moneys in the Special Public Works Fund the Economic and Community Development Department may expend funds for the purposes of administering ORS 285B.410 to 285B.479. Administrative expenses of the department, that are paid from the Special Public Works Fund, shall not exceed four percent of the moneys allocated to the fund in any biennium. As used in this section, “administrative expenses” includes the department's costs for investigating, approving and monitoring municipalities that apply for funding of infrastructure projects and servicing and collecting outstanding loans and grants made to municipalities. [Formerly 285.737]

285B.464 Certain administrative expenses chargeable to Special Public Works Fund. Notwithstanding any other provision of ORS 285B.410 to 285B.479, the costs of administering infrastructure and community development projects that are related to the purpose of the community development block grant program may be charged to the Special Public Works Fund and used as a match for federal funds available for the administration of community development block grant funds. [Formerly 285.753]

Note: 285B.464 was added to and made a part of ORS chapter 285B by legislative action but was not added to any smaller series therein. See Preface to Oregon Revised Statutes for further explanation.

285B.467 Standards for eligibility for revenue bond financing. (1) The Economic and Community Development Department shall adopt by rule standards by which to determine the eligibility for revenue bond financing under ORS 285B.467 to 285B.479 of infrastructure projects that have qualified under ORS 285B.419 to 285B.437 and 285B.449.

(2) In adopting rules establishing guidelines or criteria for awarding loans or grants for drinking water projects, the department shall coordinate the department's rulemaking process with the Water Resources Department and the Health Division of the Department of Human Services in order to assure that rules adopted under this subsection are consistent with rules adopted under ORS 431.120 and 541.845. The rules adopted under this subsection shall:

(a) Require the installation of meters on all new service connections to any distribution lines funded under ORS 285B.410, 285B.461, 285B.560 to 285B.599, 431.120, 541.700, 541.705, 541.755, 541.765, 541.830, 541.845 and this section; and

(b) Require a plan, to be adopted by the municipality, for installation of meters on all service connections throughout the drinking water system.

(3) Upon determining an infrastructure project eligible for revenue bond financing under ORS 285B.467 to 285B.479, the department shall forward the application to the State Treasurer, who shall determine whether to issue revenue bonds.

(4) Notwithstanding ORS 285B.410 (2)(a) and 285B.416 (1), when an infrastructure project is determined to be eligible for revenue bond financing under ORS 285B.467 to 285B.479, the costs for preliminary planning or legal, fiscal and economic investigations, reports and studies to determine the economic and engineering feasibility of the project are included within the total project costs of the project and may be paid from bond proceeds.

(5) Administrative expenses of the department in processing applications and investigating proposed infrastructure projects and bond sales shall not be derived from bond proceeds.

(6) The department may pledge all or any portion of the existing or future assets and receipts of the Special Public Works Fund to pay debt service on bonds issued pursuant to ORS 285B.410 to 285B.479. Such pledge shall take effect immediately, without delivery of the pledged funds to third parties, and the lien of the pledge shall be superior to all other liens of any nature.

(7) The department is authorized to establish separate accounts within the fund for separate bond issues.

(8) As used in this section, “service connection” does not include fire hydrants, fire sprinkler system connections, line blow-offs and drains, stand-by emergency interties, valve controlled drinking fountains and other similar intermittently used connections. [Formerly 285.740]

285B.470 Powers of department over revenue bond financing. In addition to any other powers granted by law in relation to an infrastructure project, the Economic and Community Development Department, acting through the State Treasurer or designee may:

(1) Make all contracts, execute all instruments and do all things necessary or convenient in the exercise of the powers granted by this section, or in the performance of its covenants or duties, or in order to secure the payment of its bonds;

(2) Enter into and perform such contracts and agreements with municipalities as the department may consider proper and feasible for or concerning the planning, construction, installation, lease or other acquisition, and the financing of infrastructure projects; and

(3) Enter into covenants for the benefit of bond owners regarding the use and expenditure of moneys in the Special Public Works Fund. [Formerly 285.743]

285B.473 Issuance of revenue bonds. If the State Treasurer determines that revenue bonds should be issued:

(1) The State Treasurer may authorize and issue in the name of the State of Oregon revenue bonds secured by moneys paid to the Special Public Works Fund pledged therefor to finance or refinance in whole or part the cost of acquisition, construction, reconstruction, improvement or extension of infrastructure projects. The bonds shall be issued in the manner prescribed by ORS chapter 286, and refunding bonds may be issued to refinance such revenue bonds.

(2) The State Treasurer shall designate the underwriter, trustee and bond counsel and enter into appropriate agreements with each to carry out the provisions of ORS 285B.467 to 285B.479. [Formerly 285.745]

285B.476 Application of law to revenue bonds. (1) ORS 285B.350 to 285B.362 and 285B.368 apply to revenue bonds issued under ORS 285B.467 to 285B.479.

(2) The proceeds of revenue bonds issued and sold under ORS 285B.467 to 285B.479 shall be deposited in the Special Public Works Fund and used for the payment of a loan to a municipality for an infrastructure project and costs of issuing the revenue bonds.

(3) A loan made with money derived from the sale of revenue bonds under this section shall be made as other loans under ORS 285B.419 to 285B.437, 285B.443 and 285B.449 are made, except that the loan contract shall set forth a schedule of payments which shall not exceed the usable life of the contracted infrastructure project. [Formerly 285.747]

285B.479 Terms of revenue bonds. (1) Revenue bonds issued under ORS 285B.467 to 285B.479:

(a) Shall not be payable from nor charged upon any funds other than the revenue pledged to the payment thereof, except as provided in this section, nor shall the state be subject to any liability thereon. No holder or holders of such bonds shall ever have the right to compel any exercise of the taxing power of the state to pay any such bonds or the interest thereon, nor to enforce payment thereof against any property of the state except those moneys pledged therefor in the Special Public Works Fund, under the provisions of ORS 285B.467 to 285B.479.

(b) Shall not constitute a charge, lien or encumbrance, legal or equitable, upon any property of the state, except those moneys paid to the Special Public Works Fund.

(c) Shall not exceed, for all bonds outstanding, a total principal amount of $200 million.

(2) No bond shall constitute a debt of the state or a lending of the credit of the state within the meaning of any constitutional or statutory limitation. [Formerly 285.750]

285B.482 Infrastructure and water bonds as parity bonds; consolidation of bond proceeds; loans and consolidated funds as security for infrastructure and water bonds; limitation on use of moneys in specified funds. (1) Notwithstanding any other law relating to revenue bonds issued and sold under ORS 285B.467 to 285B.479 or ORS 285B.572, 285B.575 and 285B.578, such revenue bonds may be issued and sold as parity bonds.

(2) Proceeds of revenue bonds issued and sold under ORS 285B.467 to 285B.479 or ORS 285B.572, 285B.575 and 285B.578, together with the investment earnings thereon, may be consolidated into one or more funds or accounts and may be pledged to the holders of revenue bonds issued to finance either water projects or infrastructure projects or to the holders of revenue bonds issued to finance both water projects and infrastructure projects.

(3) Any loan to a municipality made pursuant to ORS 285B.467 to 285B.479, 285B.560 to 285B.569 or 285B.572 to 285B.599, including loans funded in whole or in part with the proceeds of revenue bonds and loans funded with moneys in the Water Fund or the Special Public Works Fund, may be pledged to the holders of revenue bonds issued to finance either water projects or infrastructure projects or to the holders of revenue bonds issued to finance both water projects and infrastructure projects.

(4) Funds or accounts established by the Economic and Community Development Department or the State Treasurer in connection with the issuance of revenue bonds under ORS 285B.467 to 285B.479 or ORS 285B.572, 285B.575 and 285B.578 and moneys held in the funds and accounts, together with the investment earnings thereon, may be consolidated into one or more funds or accounts and may be pledged to the holders of revenue bonds issued to finance either water projects or infrastructure projects or to the holders of revenue bonds issued to finance both water projects and infrastructure projects.

(5) Notwithstanding subsections (1) to (4) of this section, moneys held in the Water Fund shall not be used to finance or refinance the cost of an infrastructure project unless the infrastructure project also qualifies as a water project, and moneys held in the Special Public Works Fund shall not be used to finance or refinance the cost of a water project unless the water project also qualifies as an infrastructure project. [1997 c.800 s.14]

Note: 285B.482 was enacted into law by the Legislative Assembly but was not added to or made a part of ORS chapter 285B or any series therein by legislative action. See Preface to Oregon Revised Statutes for further explanation.

INFRASTRUCTURE PROJECTS FOR SOUTHERN OREGON

285B.500 Policy; legislative findings. (1) The Legislative Assembly finds that:

(a) It is a matter of statewide importance to increase the infrastructure capacity of Coos, Jackson and Josephine Counties and the rest of southern Oregon.

(b) The absence of such infrastructure capacity, the lack of inexpensive industrial fuel and inadequate

transportation facilities restrict national and international trade and otherwise hinder the economic development of the region.

(c) State financial assistance to specified local projects in southern Oregon will sustain and increase jobs, foster national and international trade, allow industrial and commercial expansion and eliminate other negative effects caused by infrastructure that is inadequate to support a vibrant and expanding economy.

(d) It is desirable to make a present commitment of lottery revenues that are expected to be received in the 1999-2001 and 2001-2003 biennia. A clear and prompt financial commitment from the State of Oregon will allow the project sponsors, in reliance on that commitment, to make prompt commitments to pay their share. Prompt commitment by the project sponsors will enhance the likelihood that other private or federal funds will be received for the projects.

(2) The Legislative Assembly declares that the purpose of ORS 285B.500 to 285B.512 and section 9, chapter 644, Oregon Laws 1997, is to obligate the State of Oregon to pay the amounts specified in ORS 285B.500 to 285B.512 and section 9, chapter 644, Oregon Laws 1997, from future lottery revenues. The obligation of the state to pay the amounts specified in section 9, chapter 644, Oregon Laws, 1997, and in grant agreements authorized by ORS 285B.506 is limited to, and conditioned solely on, the availability of unobligated net lottery proceeds and any other moneys lawfully credited to the Oregon Unified International Trade Fund. Neither the faith and credit nor any of the taxing power of the State of Oregon are pledged or otherwise committed by ORS 285B.500 to 285B.515 and 777.277 to 777.289 and section 9, chapter 644, Oregon Laws 1997, and the commitments of the State of Oregon under ORS 285B.500 to 285B.515 and 777.277 to 777.289 and section 9, chapter 644, Oregon Laws 1997, and any grant agreement shall not constitute a debt or liability of the state within the meaning of section 7, Article XI of the Oregon Constitution. [1997 c.644 s.7]

Note: 285B.500 to 285B.515 were enacted into law by the Legislative Assembly but were not added to or made a part of ORS chapter 285B by legislative action. See Preface to Oregon Revised Statutes for further explanation.

285B.503 Oregon Unified International Trade Fund; purposes; sources. (1) There is established in the State Treasury, separate and distinct from the General Fund, the Oregon Unified International Trade Fund. The moneys in the fund are continuously appropriated to the Economic and Community Development Department for:

(a) Paying all or a portion of the costs of:

(A) A project for the extension and improvement of Jackson County Airport runway.

(B) A project for the extension of a natural gas pipeline to the Coos Bay and North Bend area from a location near Roseburg.

(C) A project for improvements to the Klamath Falls International Airport maintained by the City of Klamath Falls.

(b) Transfer to the Oregon Port Revolving Fund created by ORS 285A.708.

(2) A separate account within the Oregon Unified International Trade Fund shall be established for each project listed in subsection (1) of this section.

(3) The Oregon Unified International Trade Fund shall consist of moneys allocated to the fund under section 9, chapter 644, Oregon Laws 1997, and such other moneys as may be appropriated to the fund by the Legislative Assembly, including interest on such moneys. [1997 c.644 s.8]

Note: See note under 285B.500.

Note: Section 9, chapter 644, Oregon Laws 1997, provides:

Sec. 9. (1) Commencing with the fifth fiscal quarter of the 1999-2001 biennium and continuing each quarter through the end of the 2001-2003 biennium, the state shall allocate and deposit in the Oregon Unified International Trade Fund not less than $1.25 million each fiscal quarter until $15 million has been deposited into that fund. The deposits shall be made from the first available unobligated net lottery proceeds.

(2) The moneys deposited in the Oregon Unified International Trade Fund under subsection (1) of this section shall be allocated as follows:

(a) To the account for the Jackson County Airport runway project, 53.3 percent.

(b) To the account for the Coos County pipeline project, 26.7 percent.

(c) To the account for the Klamath Falls International Airport improvement project, 13.3 percent.

(d) To the Oregon Community Development Fund created by chapter 620, Oregon Laws 1997 [285A.227], 6.7 percent.

(3) Any earnings on amounts in an account listed in subsection (2) of this section shall be credited to that account. All moneys on deposit from time to time in any account, including investment earnings thereon, and all amounts required by this section to be deposited in any account shall be allocated and are hereby appropriated continuously to the Economic and Community Development Department and shall be transferred by the department to the project sponsor pursuant to a grant agreement under section 10 of this Act [285B.506] for costs of the appropriate project. [1997 c.644 s.9]

Note: Section 2, chapter 702, Oregon Laws 1999, provides:

Sec. 2. (1) Pursuant to sections 1 to 9, chapter 44, Oregon Laws 1999 [286.560 to 286.580 and 348.716], lottery bonds may be issued for the purpose of providing grant moneys to Coos County to be applied by Coos County to the payment of a portion of the costs of designing, acquiring and constructing a natural gas pipeline extending from the existing natural gas pipeline near Roseburg to the Coos Bay and North Bend area, including but not limited to the costs of acquiring all rights of way and interests in real property, machinery, equipment and structures needed for the pipeline.

(2) The use of lottery bond proceeds is authorized based on the following findings:

(a) The economy of Coos County has been depressed in recent years as a result of unfavorable developments in the timber and fishing industries.

(b) The economy of Coos County will benefit from the construction of a natural gas pipeline extending from the existing natural gas pipeline near Roseburg to the Coos Bay and North Bend area because the pipeline will enable Coos County to attract significant industries to locate in the area, thereby increasing opportunities for employment and additional economic activities that will be generated as a result of such industries.

(c) The construction of such a pipeline will therefore promote economic development within this state, and thus the use of net proceeds derived from the operation of the Oregon State Lottery to pay debt service on lottery bonds issued under this section to finance a portion of the costs of such a pipeline is an authorized use of state lottery funds under section 4, Article XV of the Oregon Constitution, and ORS 461.510.

(3) The aggregate principal amount of lottery bonds issued pursuant to subsection (1) of this section shall not exceed the sum of $20 million and an additional amount estimated by the State Treasurer to be necessary to pay bond-related costs. No lottery bonds authorized by this section shall be issued until the date upon which the presiding officer of the Board of County Commissioners of Coos County certifies in writing to the Director of the Economic and Community Development Department and the State Treasurer that the conditions set forth in subsection (5) of this section have been satisfied.

(4) Subject to subsection (3) of this section, the lottery bonds authorized by this section shall be issued in the amounts requested by the presiding officer of the Board of County Commissioners of Coos County and as soon as reasonably practicable after the presiding officer requests issuance of the lottery bonds. All requests for the issuance of lottery bonds authorized by this section shall be in writing and sent to the Director of the Economic and Community Development Department and the State Treasurer.

(5) The lottery bonds authorized by this section may not be issued until the electors of Coos County, in accordance with applicable law, authorize Coos County to issue general obligation bonds in an amount which, when added to the maximum amount of the grant to Coos County under this section and any other funds available to Coos County for such purposes, will be sufficient to pay the estimated costs of designing, acquiring and constructing the pipeline.

(6) The net proceeds from the sale of the lottery bonds authorized by this section shall be deposited in the Oregon Unified International Trade Fund. The moneys so deposited in the Oregon Unified International Trade Fund, including investment earnings thereon, are continuously appropriated to the Economic and Community Development Department for the purpose of making a grant to Coos County in accordance with subsection (7) of this section in an amount not to exceed $20 million.

(7) Prior to the issuance of the lottery bonds authorized by this section, the Economic and Community Development Department shall enter into a grant agreement with Coos County. The grant agreement shall:

(a) Provide that, promptly after issuance of lottery bonds authorized by this section and receipt of the net proceeds thereof, the Economic and Community Development Department shall pay to Coos County the net proceeds of the lottery bonds so issued;

(b) Limit aggregate payments to Coos County under the grant agreement to $20 million;

(c) Provide that Coos County hold the moneys received under the grant agreement, and the investment earnings thereon, until necessary to pay a portion of the costs of designing, acquiring and constructing the pipeline described in subsection (1) of this section;

(d) Authorize Coos County to expend the moneys received under the grant agreement from time to time for the purpose of paying a portion of the costs of designing, acquiring and constructing the pipeline described in subsection (1) of this section;

(e) Set forth procedures under which Coos County will account to the Economic and Community Development Department for the purpose of documenting that the moneys received under the grant agreement and investment earnings thereon have been expended by Coos County for the purpose authorized by this section; and

(f) Contain all additional terms, conditions and provisions that the Economic and Community Development Department considers necessary or desirable to carry out the purposes of this section. [1999 c.702 s.2]

285B.506 Grant agreements; maximum grant amount; terms of agreement; assignment of right to receive grant moneys; agreement not to constitute state debt. (1) After July 25, 1997, the Director of the Economic and Community Development Department shall enter into a grant agreement with the primary sponsor of a project listed in ORS 285B.503 that commits the State of Oregon to make the deposits specified in section 9, chapter 644, Oregon Laws 1997, and commits the Economic and Community Development Department to pay those deposits, plus earnings, to the primary sponsor as soon as funds are available in the appropriate account of the Oregon Unified International Trade Fund and are required by the primary sponsor for payment of project costs. Notwithstanding any other law, the commitment of the State of Oregon and the department under this section shall be conditioned solely on receipt by this state of unobligated net lottery proceeds sufficient to make the deposits specified in section 9, chapter 644, Oregon Laws 1997.

(2) The total amount paid to the primary sponsor under the grant agreement shall not exceed the amount deposited in the appropriate account for the sponsor's project in the Oregon Unified International Trade Fund, plus any interest earnings on the amounts in the account. The grant agreement shall:

(a) Pledge the unobligated net lottery proceeds to pay the amounts due to the primary sponsor under the grant agreement;

(b) Specify the administrative procedures for making payments to the primary sponsor;

(c) Provide for notification to the director if the primary sponsor determines that it is unable to undertake the project;

(d) Allow assignment of the right to receive amounts payable under the grant agreement to third parties;

(e) Obligate the primary sponsor to remit any unexpended grant funds and any earnings thereon to the State of Oregon after the sponsor's project is complete and all its costs have been paid; and

(f) Contain other terms and conditions that are necessary or appropriate, as determined by the Director of the Economic and Community Development Department, to implement ORS 285B.500 to 285B.512 and section 9, chapter 644, Oregon Laws 1997, to protect the interests and investments of the State of Oregon in the projects specified in ORS 285B.503.

(3) The grant agreement, when executed by the director and accepted by the primary sponsor shall be a valid, binding and irrevocable contractual obligation of the State of Oregon in accordance with its terms. However, amounts due under the grant agreement shall be payable solely from the unobligated net lottery proceeds required by section 9, chapter 644, Oregon Laws 1997, to be deposited in the appropriate account in the Oregon Unified International Trade Fund.

(4) The primary sponsor may pledge or assign its right to receive amounts due under the grant agreement as security for any contractual obligation the primary sponsor undertakes to pay or finance costs of the project. Any pledge or assignment authorized by ORS 285B.500 to 285B.515 and 777.277 to 777.289 and section 9, chapter 644, Oregon Laws 1997, shall be valid and binding upon the primary sponsor, the Economic and Community Development Department, the State of Oregon and all other persons from the date it is made. The unobligated net lottery proceeds so pledged shall be immediately subject to the lien of the pledge without physical delivery, filing or other act, and the lien of the pledge shall be superior to all other claims and liens of any kind whatsoever. Upon notice from the primary sponsor that it has pledged the unobligated net lottery proceeds or assigned the right to receive amounts due under the grant agreement, the department shall fully cooperate with the primary sponsor and the pledgee or assignee to give effect to the pledge or assignment, including but not limited to acknowledging in writing to the primary sponsor and the pledgee or assignee the existence and validity of the pledge or assignment and agreeing that amounts due under the grant agreement shall be paid to the pledgee or assignee or into the custodial accounts established for the benefit of the

pledgee or assignee.

(5) The grant agreement shall not contain provisions or be construed or enforced in any manner that may cause the grant agreement to constitute a debt or liability of the state that violates section 7, Article XI of the Oregon Constitution. [1997 c.644 s.10]

Note: See note under 285B.500.

285B.509 Agreements between primary sponsor and United States. The primary sponsors of projects listed in ORS 285B.503 are authorized to enter into agreements with agencies of the United States for the project and, notwithstanding any other provision of law, may each agree to be bound by any requirement imposed by an Act of the United States Congress as a condition of federal participation in the project. [1997 c.644 s.11]

Note: See note under 285B.500.

285B.512 End of lottery allocations upon certification by Director of Economic and Community Development Department. (1) The deposit of unobligated net lottery proceeds to an account in the Oregon Unified International Trade Fund shall cease if and when the Director of the Economic and Community Development Department certifies in writing that deposits are no longer required because:

(a) Sufficient funds are on hand in the account to pay all amounts required to be paid under the grant agreement;

(b) All amounts required to be paid under the grant agreement have been paid; or

(c) The primary sponsor has notified the director pursuant to the grant agreement that the primary sponsor is unable to undertake the project.

(2) Upon receipt of the director's written certification pursuant to subsection (1) of this section, the State Treasurer shall thereafter credit any amounts remaining in the account that are not required to pay amounts due under the grant agreement, and any lottery revenues that otherwise would have been deposited in the account under section 9, chapter 644, Oregon Laws 1997, to the Administrative Services Economic Development Fund. In addition, any unexpended grant funds and earnings which are remitted to the State of Oregon pursuant to the grant agreement shall be credited to the Administrative Services Economic Development Fund. [1997 c.644 s.12]

Note: See note under 285B.500.

285B.515 "Primary sponsor" defined for ORS 285B.500 to 285B.512. As used in ORS 285B.500 to 285B.512 and section 9, chapter 644, Oregon Laws 1997, "primary sponsor" or "project sponsor" means a city, county, agency or person who acts as a financial contributor to a project listed in ORS 285B.503, as determined by the Economic and Community Development Department in a grant agreement under ORS 285B.506. [1997 c.644 s.13]

Note: See note under 285B.500.

LOTTERY BONDS FOR INFRASTRUCTURE PROJECTS

285B.530 Definitions for ORS 285B.530 to 285B.548. As used in ORS 285B.530 to 285B.548, unless the context requires otherwise:

(1) "Infrastructure lottery bonds" means the bonds authorized to be issued under ORS 285B.533 for the purpose of financing infrastructure projects.

(2) "Infrastructure projects" includes:

(a) A water project defined in ORS 285B.560; and

(b) Payment of any state financial obligations to the federal government under the Safe Drinking Water Act. [1997 c.800 s.16; 1999 c.44 s.24]

Note: 285B.530 to 285B.548 were enacted into law by the Legislative Assembly but were not added to or made a part of ORS chapter 285B by legislative action. See Preface to Oregon Revised Statutes for further explanation.

285B.533 Issuance of infrastructure lottery bonds; amount; use of bond proceeds. (1) Infrastructure lottery bonds shall be issued under ORS 286.560 to 286.580 and 348.716 only at the request of the Director of the Economic

and Community Development Department. Infrastructure lottery bonds may be issued in an amount sufficient to provide no more than $6 million of net proceeds to pay costs of infrastructure projects, plus the amounts required to pay bond-related costs.

(2) The net proceeds from the sale of the infrastructure lottery bonds shall be allocated to the Economic and Community Development Department for the State of Oregon's match of federal moneys under the Safe Drinking Water Act.

(3) The net proceeds from the sale of the infrastructure lottery bonds that are available to pay costs of infrastructure projects shall be credited to the Water Fund created by ORS 285B.563. All such net proceeds are appropriated continuously to the Economic and Community Development Department only for payment of costs of infrastructure projects described in subsection (2) of this section and for payment of bond-related costs that are allocable to infrastructure lottery bonds.

(4) The Economic and Community Development Department and any municipality receiving proceeds of infrastructure lottery bonds shall, if so directed by the Oregon Department of Administrative Services, take any action specified by the Oregon Department of Administrative Services that is necessary to maintain the excludability of lottery bond interest from gross income under the United States Internal Revenue Code. [1997 c.800 s.17; 1999 c.44 s.25]

Note: See note under 285B.530.

285B.536 [1997 c.800 s.18; repealed by 1999 c.44 s.29]

285B.539 [1997 c.800 s.19; repealed by 1999 c.44 s.29]

285B.542 [1997 c.800 s.20; repealed by 1999 c.44 s.29]

285B.545 [1997 c.800 s.21; repealed by 1999 c.44 s.29]

285B.548 Amount of infrastructure lottery bonds. (1) Notwithstanding ORS 286.505 to 286.545, infrastructure lottery bonds may be issued during the 1997-1999 biennium in an aggregate principal amount that produces net proceeds for infrastructure projects that shall not exceed $6 million, plus an amount that the State Treasurer estimates will be required to pay bond-related costs.

(2) In future biennial periods, the amount of infrastructure lottery bonds that may be issued shall be authorized under ORS 286.505 to 286.545. [1997 c.800 s.22]

Note: See note under 285B.530.

285B.551 Issuance of additional lottery bonds; amount; use of bond proceeds; Economic Infrastructure Project Fund. (1) Pursuant to ORS 286.560 to 286.580 and 348.716, lottery bonds may be issued:

(a) To provide financial and other assistance, including but not limited to loans and grants, to municipalities, ports and other persons and entities in accordance with the laws governing use of moneys in the Special Public Works Fund created by ORS 285B.455, the Water Fund created by ORS 285B.563, the Safe Drinking Water Revolving Loan Fund created by ORS 285A.213, the Oregon Port Revolving Fund created by ORS 285A.708, the Brownfields Redevelopment Loan Fund created by ORS 285A.188 and the Marine Navigation Improvement Fund created by ORS 777.267.

(b) To fund Oregon's share of the costs of the Columbia River channel deepening project.

(2) The use of lottery bond proceeds is authorized based on the following findings:

(a) The financial and other assistance to municipalities, ports and other persons and entities will assist in the construction, improvement and expansion of infrastructure, community and port facilities and other facilities that comprise the physical foundation for industrial and commercial activity and provide the basic framework for continued and expanded economic opportunities and quality communities throughout Oregon.

(b) The Columbia River channel deepening project is necessary to allow newer, larger steamships access to Oregon and Washington deep draft ports. A deeper shipping channel will allow the Columbia River to continue as a world leader in agricultural exports and as a key trade corridor for farms and businesses throughout Oregon and the region.

(c) Such financial and other assistance to municipalities, ports and other persons and entities and the deepening of

the Columbia River channel will therefore promote economic development within this state, and thus the use of net proceeds derived from the operation of the Oregon State Lottery to pay debt service on lottery bonds issued under this section to provide such financial and other assistance to municipalities, ports and other persons and entities and to pay a portion of the costs of deepening the Columbia River channel is an authorized use of state lottery funds under section 4, Article XV of the Oregon Constitution, and ORS 461.510.

(3) The aggregate principal amount of lottery bonds issued pursuant to subsection (1)(a) of this section for financial and other assistance to municipalities, ports and other persons and entities shall not exceed the sum of $45 million and an additional amount estimated by the State Treasurer to be necessary to pay bond-related costs. The aggregate principal amount of lottery bonds issued pursuant to subsection (1)(b) of this section for the Columbia River channel deepening project shall not exceed the sum of $17.7 million and an additional amount estimated by the State Treasurer to be necessary to pay bond-related costs. Lottery bonds issued pursuant to this section shall be issued only at the request of the Director of the Economic and Community Development Department. The director shall not request the issuance of lottery bonds pursuant to subsection (1)(b) of this section until a final environmental impact statement has been issued and a record of decisions has been submitted to Congress by the United States Army Corps of Engineers, Congress has authorized the Columbia River channel deepening project, and the Washington sponsors' shares of the costs of the Columbia River channel deepening project have been committed.

(4) The net proceeds of lottery bonds issued pursuant to this section shall be deposited in the Economic Infrastructure Project Fund, which is hereby established in the State Treasury separate and distinct from the General Fund. All moneys in the Economic Infrastructure Project Fund are continuously appropriated to the Economic and Community Development Department for any purpose for which moneys in the Special Public Works Fund created by ORS 285B.455 may be used, any purpose for which moneys in the Water Fund created by ORS 285B.563 may be used, any purpose for which moneys in the Safe Drinking Water Revolving Loan Fund created by ORS 285A.213 may be used, any purpose for which moneys in the Oregon Port Revolving Fund created by ORS 285A.708 may be used, any purpose for which moneys in the Brownfields Redevelopment Loan Fund created by ORS 285A.188 may be used and any purpose for which moneys in the Marine Navigation Improvement Fund created by ORS 777.267 may be used. The Director of the Economic and Community Development Department shall allocate the moneys deposited in the Economic Infrastructure Project Fund for the purposes described in this subsection in accordance with the policies developed by the Oregon Economic and Community Development Commission in accordance with ORS 285A.045. However, the director shall transfer from the Economic Infrastructure Project Fund to the Marine Navigation Improvement Fund the proceeds of any lottery bonds sold to finance a portion of the costs of the Columbia River channel deepening project. Upon determining the relative allocation of moneys deposited in the Economic Infrastructure Project Fund among the purposes described in this subsection, the director shall transfer from the Economic Infrastructure Project Fund, and deposit into each of the other funds described in this subsection, the amounts so allocated. Notwithstanding any other provision of law governing the funds described in this subsection, the funds described in this subsection may be credited with moneys transferred from the Economic Infrastructure Project Fund by the director in accordance with this subsection.

(5) The proceeds of lottery bonds issued pursuant to this section shall be used only for the purposes set forth in subsection (4) of this section and for bond-related costs. [1999 c.702 s.1]

Note: 285B.551 was enacted into law by the Legislative Assembly but was not added to or made a part of ORS chapter 285B or any series therein by legislative action. See Preface to Oregon Revised Statutes for further explanation.

Note: Sections 6 and 8 (2), chapter 702, Oregon Laws 1999, provide:

Sec. 6. (1) Pursuant to sections 1 to 9, chapter 44, Oregon Laws 1999 [286.560 to 286.580 and 348.716], lottery bonds may be issued to fund projects for the development and improvement of systems, facilities and equipment of the Oregon Garden in Silverton.

(2) The use of lottery bond proceeds is authorized based on the following findings:

(a) The activities of the Oregon Garden promote Oregon's horticultural industry and its products;

(b) The promotion of horticultural products expands markets, which in turn creates jobs and stimulates economic development of the industry; and

(c) The Oregon Garden will attract tourists from throughout the nation and world and thereby generate substantial economic activity for Marion County.

(3) The aggregate principal amount of lottery bonds issued pursuant to this section shall not exceed the sum of $1 million and an additional amount estimated by the State Treasurer to be necessary to pay bond-related costs. Lottery bonds issued pursuant to this section shall be issued only at the request of the Director of the Economic and Community Development Department.

(4) The net proceeds of lottery bonds issued pursuant to this section shall be deposited in the Economic Infrastructure Project Fund established under section 1 of this 1999 Act [285B.551].

(5) The proceeds of lottery bonds issued pursuant to this section shall be used only for the purposes set forth in subsection (1) of this section and for bond-related costs. [1999 c.702 s.6]

Sec. 8. (2) The Economic and Community Development Department shall pay amounts required for debt service on lottery bonds issued during the 1999-2001 biennium under sections 1 [285B.551], 2, 3 [458.720] and 6 of this 1999 Act from moneys allocated to the department from the Administrative Services Economic Development Fund. [1999 c.702 s.8(2)]

SAFE DRINKING WATER PROJECTS

(Generally)

285B.560 Definitions for ORS 285B.560 to 285B.599. As used in ORS 285B.560 to 285B.599:

(1) “Department” means the Economic and Community Development Department.

(2) “Fund” means the Water Fund.

(3) “Municipality” has the meaning given that term in ORS 285B.410.

(4) “Safe drinking water project” means a project for constructing or improving a drinking water system or a water development project, as defined in ORS 541.700 (6)(a), (b) and (d) to (f), that is owned and operated by a municipality.

(5) “Waste water system improvement project” means a project for constructing or improving a system for waste water collection or treatment, including storm drainage systems.

(6) “Water project” means a safe drinking water project or a waste water system improvement project. [Formerly 285.755]

285B.563 Water Fund; uses; sources; maintenance of fund value; coordination with other agencies on safe drinking water projects. (1) There is established in the State Treasury, separate and distinct from the General Fund, the Water Fund. All moneys in the fund are continuously appropriated to the Economic and Community Development Department to provide financing for water projects.

(2)(a) Moneys in the Water Fund may be obligated to water projects.

(b) Moneys shall be used primarily to make loans to municipalities. The department may make a loan only if:

(A) The municipality applying for the loan certifies to the department that adequate funds will be available to repay the loan; and

(B) The department determines that the amount of the loan applied for is based on a reasonable and prudent expectation of the municipality's ability to repay the loan.

(c) The department may award a grant only if a loan is not feasible due to:

(A) Financial hardship to the municipality, as determined by the department, based on consideration of anticipated water service charges or anticipated waste water service charges that exceed the statewide average for such charges, the per capita income of the municipality and such other factors as the department by rule may establish; and

(B) Special circumstances of the water project.

(d) The department may determine the amount of grant or loan funding on a case-by-case basis.

(3) The moneys in the fund may also be used to assist the department in selling revenue bonds on behalf of municipalities in order to carry out the purposes of ORS 285B.560 to 285B.599.

(4) With the approval of the State Treasurer, moneys in the Water Fund may be invested as provided by ORS 293.701 to 293.820. The earnings from such investments and other program income shall be credited to the Water Fund.

(5) The Water Fund shall consist of:

(a) Moneys appropriated to the fund by the Legislative Assembly.

(b) Moneys transferred to the fund by the Economic and Community Development Department from the Special

Public Works Fund created by ORS 285B.455.

(c) Moneys transferred to the fund by the Water Resources Commission from the Water Development Fund created by Article XI-I(1) of the Oregon Constitution.

(d) Moneys from any federal, state or other grants.

(e) Proceeds of revenue bonds issued under ORS 285B.575.

(f) Earnings on the fund.

(6) The department shall administer the fund.

(7) The department shall adopt rules and policies for the administration of the fund. The department shall coordinate its rulemaking regarding safe drinking water projects with the Water Resources Department and the Health Division of the Department of Human Services. The rules adopted under this subsection for safe drinking water projects shall:

(a) Require the installation of meters on all new service connections to any distribution lines funded with moneys from the fund or from the proceeds of revenue bonds issued under ORS 285B.572 to 285B.578.

(b) Require a plan, to be adopted by a municipality receiving financial assistance from the fund, for installation of meters on all service connections throughout the drinking water system not later than two years after the completion of a safe drinking water project.

(8)(a) The Economic and Community Development Department shall manage the Water Fund and any expenditures from accounts in the fund and transfers between accounts so that the fund value shall be equal to at least 50 percent of lottery revenues actually transferred to the fund plus interest on such amounts compounded annually at five percent. The fund value shall be determined by adding the cash reserves and the outstanding principal amount of loans to municipalities. Any amount of loan principal that is forgiven shall be subtracted from the value of the fund. The value of the fund shall include moneys in the fund that are pledged to the repayment of state bonds.

(b) The department shall certify to the State Treasurer in each quarter the value of the fund.

(c) If necessary to ensure repayment of bonds issued under ORS 285B.560 to 285B.599, the department may reduce the value of the fund to less than the limit established in paragraph (a) of this subsection when the department:

(A) Finds that without such a reduction in fund value, bonds secured by the fund are likely to be in default; and

(B) Imposes a moratorium on grants until the requirements of paragraph (a) of this subsection are satisfied.

(9)(a) The department may charge administrative costs to the fund, but not to moneys segregated in the account created by subsection (11) of this section, to pay for administrative expenses incurred by the department for processing applications, investigating water projects, monitoring recipients of financing for water projects and servicing and collecting outstanding financial awards made for water projects.

(b) To the extent permitted by federal law, administrative expenses of the department as limited in paragraph (a) of this subsection that are paid from the fund shall not exceed four percent of the moneys allocated to the fund in any biennium. Administrative expenses of the department as limited in paragraph (a) of this subsection may be paid from bond proceeds.

(10) The department may establish other accounts within the Water Fund for the payment of water projects costs, reserves, debt service payments, credit enhancements, costs of issuing revenue bonds, administrative and operating expenses or any other purpose necessary to carry out ORS 285B.560 to 285B.599.

(11) There is created within the Water Fund a separate and distinct account for the proceeds from the sale of water development general obligation bonds issued for safe drinking water projects and credited to the special account under this section. Any investment earnings thereon shall be segregated in and continuously appropriated to a special, separately accounted for subaccount of this account. Moneys credited to this account shall be maintained separate and distinct from moneys credited to subaccounts created under subsection (10) of this section. Notwithstanding ORS 285B.566 or subsection (4) of this section, all repayments of moneys loaned from the account created by this subsection, including interest on such moneys, shall be credited to the Water Development Administration and Bond Sinking Fund created by ORS 541.830. [Formerly 285.757; 1999 c.509 s.45]

285B.566 Use of receipts from projects. All payments, receipts and interest from financial awards made for water projects shall be retained and accumulated in the Water Fund and used to finance water projects including payments to holders of revenue bonds issued under ORS 285B.575. [Formerly 285.760]

285B.569 When constitutional restrictions apply to use of certain funds. If moneys are transferred to the Water Fund from the sources described in ORS 285B.563 (5)(b) to (e), all constitutional restrictions, statutes and rules regulating the use of the moneys transferred from these funds shall apply to the use of those moneys in the Water

Fund. [Formerly 285.763]

(Revenue Bond Financing of Safe Drinking Water Projects)

285B.572 Standards for eligibility of water projects; determination to issue bonds. (1) The Economic and Community Development Department shall adopt by rule standards to determine the eligibility of a water project for revenue bond financing under ORS 285B.560 to 285B.599.

(2) Upon determining that a water project is eligible for revenue bond financing, the department shall forward a description of the project to the State Treasurer. The State Treasurer shall determine whether to issue revenue bonds. [Formerly 285.950]

285B.575 Duties of State Treasurer. If the State Treasurer determines that revenue bonds shall be issued:

(1) The State Treasurer may authorize and issue in the name of the State of Oregon revenue bonds secured by moneys paid to the Water Fund and pledged to finance or refinance in whole or in part the cost of a water project. The revenue bonds issued under this section shall be issued in the manner prescribed by ORS chapter 286, and refunding bonds may be issued to refinance the revenue bonds.

(2) The State Treasurer shall designate and enter into agreements with the underwriter, trustee and bond counsel to carry out the provisions of ORS 285B.560 to 285B.599. [Formerly 285.952]

285B.578 Nature of revenue bonds. (1) Revenue bonds issued under ORS 285B.575:

(a) Shall not be payable from nor charged upon any fund other than the revenue pledged to the payment of the revenue bonds, except as provided in this section, nor shall the state be subject to any liability on the bonds. No holder of revenue bonds shall ever have the right to compel any exercise of the taxing power of the state to pay any such bonds or the interest on the bonds, nor to enforce payment of the bonds against any property of the state except those moneys pledged in the Water Fund, under the provisions of ORS 285B.560 to 285B.599.

(b) Shall not constitute a charge, lien or encumbrance, legal or equitable, upon any property of the state, except those moneys paid to the Water Fund.

(c) Shall not exceed, for all bonds outstanding, a total principal amount of $200 million.

(2) A revenue bond issued under ORS 285B.575 shall not constitute a debt of the state or a lending of the credit of the state within the meaning of any constitutional or statutory limitation. [Formerly 285.954]

285B.581 Repayment plans for loan; authority of municipalities. (1) Any loan of moneys to a municipality by the state shall include a plan for repayment by the municipality of moneys borrowed from the Water Fund for a water project and interest on those moneys at a rate expressly specified. The repayment plan:

(a) Shall provide for such evidence of debt assurance of, and security for, repayment by the municipality as is considered necessary by the Economic and Community Development Department.

(b) May set forth the allocation of special assessments or contractual responsibilities among the owners of benefited properties for repayment to the municipality of the amount of the loan.

(c) Shall provide for repayment during a period that shall not exceed the usable life of the proposed project or 25 years, whichever is less.

(2) Notwithstanding any other provision of law or any restriction on indebtedness contained in a charter, a municipality may borrow from the fund by entering into a loan contract with the Economic and Community Development Department. Moneys borrowed from the fund shall be repaid:

(a) From the revenues of any water project, including special assessment revenues;

(b) From amounts withheld under ORS 285B.599;

(c) From the general fund of the municipality;

(d) From any combination of the provisions of paragraphs (a) to (c) of this subsection; or

(e) From any other sources.

(3) A loan contract under subsection (2) of this section may provide that a portion of the proceeds of the loan be applied to fund a reserve fund to secure the repayment of the loan or secure the repayment of revenue bonds issued to fund the loan.

(4) A loan contract under subsection (2) of this section shall be authorized by an ordinance or resolution that is adopted with prior notice of at least 14 days. Notice shall be published at least once in a newspaper of general circulation within the municipality. [Formerly 285.956]

285B.584 Authority of department. In addition to any other powers granted by law in relation to a water project, the Economic and Community Development Department, acting through the State Treasurer or the State Treasurer's designee, may:

(1) Make all contracts, execute all instruments and do all things necessary or convenient for the exercise of the powers granted by this section, or for the performance of its covenants or duties, or in order to secure the payment of its bonds;

(2) Enter into and perform such contracts and agreements with municipalities as the department may consider proper and feasible for or concerning the planning, construction, installation, lease or other acquisition, and the financing of water projects; and

(3) Enter into covenants for the benefit of bond owners regarding the use and expenditure of moneys in the Water Fund. [Formerly 285.958]

285B.587 Deposit and use of bond proceeds. (1) Proceeds of revenue bonds issued and sold under ORS 285B.572 to 285B.578 that are to be used to fund loans to municipalities for water projects shall be deposited in the Water Fund.

(2) Proceeds of revenue bonds issued and sold under ORS 285B.572 to 285B.578 that are to be used to pay the costs of issuing the revenue bonds or that are to be applied to fund a reserve fund for the revenue bonds shall be deposited either in the Water Fund or in a trust account or fund held by any trustee for the revenue bonds. Moneys on deposit in the Water Fund may be transferred to any trustee for the revenue bonds to be applied to the payment of the costs of issuing the revenue bonds or to be applied to fund a reserve fund for the revenue bonds. [Formerly 285.960]

285B.590 Other forms of financial assistance. In addition to making loans to municipalities for water projects, the Economic and Community Development Department may provide any other form of financial assistance that the department may consider appropriate for the financing of water projects. [Formerly 285.962]

285B.593 Technical assistance grants and loans; eligibility; purpose; amount. Out of the moneys in the Water Fund, the Economic and Community Development Department may make technical assistance grants and loans to municipalities with fewer than 5,000 residents. Technical assistance grants and loans shall be for the purpose of completing preliminary planning, legal, fiscal and economic investigations, reports and studies to determine the economic and engineering feasibility of water projects. A technical assistance grant shall not exceed $10,000. A technical assistance loan shall not exceed $20,000. [Formerly 285.964]

285B.596 Use of moneys in Water Fund. Not less than 33 percent of the moneys appropriated to the Water Fund shall be used to provide financial assistance to nonurban water projects and not less than 33 percent shall be used to provide financial assistance to urban water projects. [Formerly 285.966]

285B.599 Repayment to Water Fund. (1) If a municipality fails to comply with a contract entered into under ORS 285B.581, the Economic and Community Development Department may seek appropriate legal remedies to secure any repayment due the Water Fund. If any municipality defaults on payments due the fund, the State of Oregon may withhold any amounts otherwise due the municipality to apply to the indebtedness. The department may waive the right to withhold moneys under this subsection.

(2) Moneys withheld under subsection (1) of this section shall be deposited in the fund and shall be used to repay any account in the fund from which funds were expended to pay obligations upon which the municipality defaulted. [Formerly 285.968]

ENTERPRISE ZONES

(Generally)

285B.650 Definitions for ORS 285B.650 to 285B.728. As used in ORS 285B.650 to 285B.728, unless the context requires otherwise:

(1) “Business firm” means a person operating or conducting one or more trades or businesses but does not include any governmental agency, municipal corporation or nonprofit corporation.

(2) "Eligible business firm" means a firm engaged in an activity described under ORS 285B.707 which may file an application for precertification under ORS 285B.719.

(3) "Employee" means a person who works more than 32 hours per week, but does not include persons with temporary or seasonal jobs or persons hired solely to construct qualified property.

(4) "Enterprise zone" means one of the 30 areas designated or terminated and redesignated by order of the Governor under ORS 284.160 (1987 Replacement Part) before October 3, 1989, one of the 17 areas designated by the Director of the Economic and Community Development Department under ORS 285B.653, areas designated under ORS 285B.677 and areas designated under ORS 285B.689.

(5) "First-source hiring agreement" means an agreement between a precertified business firm and a publicly funded job training provider whereby the job training provider refers qualified candidates to the firm for new jobs and job openings in the firm.

(6) "Modification" means modernization, renovation or remodeling of an existing building or structure.

(7) "Nonurban enterprise zone" means an enterprise zone located outside a regional or metropolitan urban growth boundary.

(8) "Precertified business firm" means an eligible business firm whose application for precertification has been approved under ORS 285B.719 and which may apply for a property tax exemption under ORS 285B.722.

(9) "Publicly funded job training provider" includes but is not limited to, community colleges, Job Training Partnership Act service providers, and other similar programs.

(10) "Qualified business firm" means a business firm described in ORS 285B.704 whose application for a property tax exemption has been approved under ORS 285B.722.

(11) "Qualified property" means property described under ORS 285B.713.

(12) "Sponsor" means the city or county that applied for and received approval of an enterprise zone under ORS 284.150 and 284.160 (1987 Replacement Part), under ORS 285B.656 and 285B.659, under ORS 285B.677 or 285B.686 or under ORS 285B.689.

(13) "Urban enterprise zone" means an enterprise zone in a metropolitan statistical area, as defined by the most recent federal decennial census, located inside a regional or metropolitan urban growth boundary. [Formerly 285.560; 1999 c.460 s.1]

Note: Section 22, chapter 1015, Oregon Laws 1989, and sections 31 to 33, chapter 835, Oregon Laws 1997, provide:

Sec. 22. ORS 285B.650, 285B.665, 285B.668, 285B.671, 285B.674, 285B.677, 285B.680, 285B.686, 285B.692, 285B.695, 285B.698, 285B.704, 285B.707, 285B.710, 285B.713, 285B.716, 285B.719, 285B.722, 285B.728 and 285B.731 are repealed on June 30, 2009. [1989 c.1015 s.22; 1995 c.747 s.5]

Sec. 31. ORS 285B.653, 285B.656, 285B.659, 285B.662, 285B.683, 285B.689, 285B.701 and 285B.725 and section 2 of this 1999 Act [285B.723] are repealed on June 30, 2009.
[1997 c.835 s.31; 1999 c.1104 s.9]

Sec. 32. Notwithstanding ORS 285B.686, all enterprise zones terminate on the date on which the statutes listed in section 31 of this Act and in section 22, chapter 1015, Oregon Laws 1989, are repealed. [1997 c.835 s.32]

Sec. 33. Notwithstanding the repeal of the statutes listed in section 31 of this Act and in section 22, chapter 1015, Oregon Laws 1989, and notwithstanding the termination of an enterprise zone under section 32 of this Act, precertified or qualified business firms in an enterprise zone on the date of repeal or termination shall receive the tax exemptions provided under ORS 285B.686 (2) or 285B.719 (5) and (6). [1997 c.835 s.33]

285B.653 Nonurban enterprise zones; designation. (1) The Director of the Economic and Community Development Department may approve the designation of up to 17 areas as nonurban enterprise zones as provided in ORS 285B.656 and 285B.659.

(2) Areas designated as enterprise zones under this section shall be in addition to the 30 areas designated or redesignated as enterprise zones by order of the Governor under ORS 284.160 (1987 Replacement Part) before October 3, 1989, and areas designated under ORS 285B.677 and 285B.689 and shall terminate in accordance with ORS 285B.686 (3). [Formerly 285.562; 1999 c.460 s.2]

Note: Sections 4 and 5, chapter 460, Oregon Laws 1999, provide:

Sec. 4. (1) As used in this section, "eastern Oregon" has the meaning given that term in ORS 321.405 but also includes Hood River County.

(2) Of the 10 additional enterprise zones provided for in the amendments to ORS 285B.653 by section 2 of this 1999 Act and initially designated after the effective date of this 1999 Act [October 23, 1999], at least four of the enterprise zones must be located in eastern Oregon.

(3) The designation of any enterprise zone provided for in the amendments to ORS 285B.653 by section 2 of this 1999 Act is not effective unless made on or before January 1, 2004.

(4) When requesting a change to the boundary of an enterprise zone under ORS 285B.680, the zone sponsor and any other city or county that seeks to become a sponsor as part of the boundary change proceeding may request a waiver of the distance limit imposed under ORS 285B.683 (1)(c). The Director of the Economic and Community Development Department shall grant the waiver and order the change to the enterprise zone boundary, if:

(a) The proposed boundary change satisfies all other requirements for a boundary change; and

(b) The director makes a determination, consistent with rules adopted by the Economic and Community Development Department, that designation of a separate enterprise zone is not a practical option under the particular circumstances, that the overall distances involved can be effectively administered and that the waiver will further the goals and purposes of applicable state policies. [1999 c.460 s.4]

Sec. 5. Section 4 of this 1999 Act is repealed on January 1, 2008. [1999 c.460 s.5]

Note: See note under 285B.650.

285B.656 Application for designation of enterprise zones; contents of application. (1) Any city or county may apply to the Director of the Economic and Community Development Department for designation of an area within that city or county as an enterprise zone. With the prior consent of the governing body of the city, a county may apply to the Economic and Community Development Department on behalf of a city for designation of any area within that city as an enterprise zone.

(2) One or more cities and counties may apply to the director for designation of an area situated partly within each city and partly in unincorporated territory within the counties as an enterprise zone.

(3) Any area proposed for designation as an enterprise zone must consist of a total area of not more than 12 square miles in size with 12 miles or less as the greatest distance between any two points within the zone. The area of the zone shall be calculated by excluding that portion of the zone which lies below the ordinary high water mark of a navigable body of water, and any road, railroad, electric transmission line or pipeline rights of way that connect otherwise unconnected areas of an enterprise zone. Such areas shall not be more than five miles apart.

(4) An application for designation of an enterprise zone shall be in the form and contain such information as the department, by rule, may require. However, the application shall:

(a) Be submitted on behalf of one or more local government units as described in subsections (1) and (2) of this section by action of the governing body of each applicant;

(b) Contain a description of the area sought to be designated as an enterprise zone;

(c) Contain information sufficient to allow the department to determine if the criteria established in ORS 285B.662 are met;

(d) State that the applicant will give priority to the use in the proposed enterprise zone of any economic development or job training funds received from the federal government; and

(e) Declare that the applicant will comply with ORS 285B.671.

(5) When applying for designation of an enterprise zone within its boundaries under this section, the applicant may include in the application proposals to enhance the level or efficiency of local public services within the proposed enterprise zone including, but not limited to, fire-fighting and police services.

(6) When applying for designation of an enterprise zone within its boundaries under this section, the applicant may include in the application proposals for local incentives and local regulatory flexibility to precertified or qualified business firms.

(7) In the case of joint applications by more than one local government unit, each city or county joining in the application may include proposals for enhanced local public services, local incentives or local regulatory flexibility to

be effective within the boundaries of that local government unit.

(8) Proposals under subsection (5), (6) or (7) of this section for enhanced local public services, local incentives or local regulatory flexibility included in the application by a city or county for an enterprise zone are binding upon the city or county if an enterprise zone is designated wholly or partly within its boundaries.

(9) Notwithstanding ORS 285B.716 (1), when applying for designation of an enterprise zone, an applicant may choose to exempt qualified property owned or leased and operated by a business firm as a hotel, motel or destination resort, for any business firm that is precertified in the proposed zone after its designation, if the exemption is requested by resolution of each city or county sponsoring the application. [Formerly 285.563]

Note: See note under 285B.650.

285B.659 Review of applications by department; approval; reapplication upon denial. (1) The Economic and Community Development Department shall review each application for designation of an enterprise zone, and shall secure any additional information that the department considers necessary for the purpose of determining whether the area described in the application qualifies for designation as an enterprise zone.

(2) The department shall complete review of the application within 60 days of the last date designated for receipt of an application. After review of the applications, the department shall forward those qualified applications to the Director of the Economic and Community Development Department. The director shall determine which applications have the greatest potential for accomplishing the purposes of ORS 285B.650 to 285B.728.

(3) As authorized under ORS 285B.653 or 285B.689, the director may approve the designation of one or more enterprise zones. The determination by the director as to the areas designated enterprise zones shall be final.

(4) If an application for enterprise zone designation is denied, the governing body of the cities or counties submitting the application shall be informed of that fact together with the reasons for the denial. Cities or counties may reapply to the department for designation of an area as an enterprise zone. [Formerly 285.564]

Note: See note under 285B.650.

285B.662 Requirements for area designated as enterprise zone. A proposed enterprise zone must be located in a local area in which:

(1) Fifty percent or more of the households have incomes below 80 percent of the median income of this state, as defined by the most recent federal decennial census;

(2) The unemployment rate is at least 2.0 percentage points greater than the comparable unemployment rate for this entire state, as defined by the most recently available data published or officially provided and verified by the United States Government, the Employment Department of this state, the Portland State University Center for Population Research and Census or special studies conducted under a contract with a regional academic institution; or

(3) The Economic and Community Development Department determines on a case-by-case basis using evidence provided by the cities or counties applying for designation of the proposed enterprise zone that there exists a level of economic hardship at least as severe as that described in subsection (1) or (2) of this section. Such evidence shall be based on the most recently available data from official sources and may include, but is not limited to, a contemporary decline of the population in the proposed enterprise zone, the percentage of persons in the proposed enterprise zone below the poverty level relative to the percentage of the entire population of this state below the poverty level or the unemployment rate for the county or counties in which the proposed enterprise zone is located. [Formerly 285.565]

Note: See note under 285B.650.

285B.665 Legislative findings. The Legislative Assembly finds and declares that the health, safety and welfare of the people of this state are dependent upon the continued encouragement, development, growth and expansion of employment, business, industry and commerce throughout all regions of the state, but especially in those communities at the center of or outside major metropolitan areas for which geography may act as an economic hindrance. The Legislative Assembly further declares that there are areas in the state that need the particular attention of government to help attract private business investment into these areas and to help resident businesses to reinvest and grow and that many local governments wish to have tax incentives and other assistance available to stimulate sound business investments that support and improve the quality of life. Therefore, it is declared to be the purpose of ORS 285B.650 to 285B.728 to stimulate and protect economic success in such areas of the state by providing tax incentives for

employment, business, industry and commerce and by providing adequate levels of complementary assistance to community strategies for such interrelated goals as environmental protection, growth management and efficient infrastructure. [Formerly 285.573; 1999 c.460 s.6]

Note: See note under 285B.650.

285B.668 Duties of department. In addition to any other powers granted by law, for the purpose of administering ORS 285B.650 to 285B.728, the Economic and Community Development Department shall:

(1) Adopt any rules the department considers necessary to administer ORS 285B.650 to 285B.728.

(2) Assist a sponsor of an enterprise zone in its efforts to retain, expand, start or recruit eligible business firms.

(3) Assist an eligible business firm doing business within an enterprise zone to obtain the benefits of applicable incentive or inducement programs authorized by Oregon law.

(4) Take action necessary to participate in the federal enterprise zone program under ORS 285B.677.

(5) Process sponsor requests for boundary amendments under ORS 285B.680.

(6) Take action necessary to terminate or designate zones under ORS 285B.686 or 285B.689.

(7) Assist in implementing first-source hiring agreements by publicly funded job training providers with precertified and qualified business firms. [Formerly 285.575]

Note: See note under 285B.650.

285B.671 Duties of zone sponsor. (1) The sponsor of an enterprise zone shall:

(a) Appoint a local zone manager. Upon appointment of the local zone manager, the sponsor shall provide written notice thereof to the Economic and Community Development Department, the county assessor and the Department of Revenue.

(b) Provide enhanced local public services, local incentives and local regulatory flexibility included in the application for designation of the enterprise zone or in the resolution under ORS 285B.680 (6) to precertified or qualified business firms.

(c) Process applications from eligible business firms for precertification under ORS 285B.719.

(d) Assist the county assessor in reviewing tax exemption applications under ORS 285B.722.

(e) Prepare, implement and annually update a plan for marketing the enterprise zone including strategies for retention, expansion, start-up and recruitment of eligible business firms.

(f) Manage the enterprise zone in accordance with ORS 285B.650 to 285B.728.

(g) Identify property available for sale or lease to eligible business firms under ORS 285B.674.

(h) Prepare indices of street addresses, tax lot numbers or other information to facilitate the identification of land inside of an urban enterprise zone.

(2) A sponsor of an enterprise zone may require that an application for precertification be accompanied by a filing fee of $200 or up to one-tenth of one percent of the value of the proposed investment in qualified property at the time of the precertification.

(3) If more than one city or county sponsors an enterprise zone, they shall act jointly in performing the duties imposed on a sponsor under ORS 285B.650 to 285B.728.

(4) Notwithstanding ORS 285B.719 (3), the sponsor of an urban enterprise zone may require an eligible business firm seeking precertification under ORS 285B.719 within that zone to satisfy other conditions for precertification that the zone sponsor may impose that are reasonably related to the public purpose of providing opportunities for groups of persons, as defined by the zone sponsor, to obtain employment, including but not limited to provisions for training and procedures for monitoring and verifying compliance with the conditions. Such conditions may be imposed only pursuant to a policy adopted by the zone sponsor that establishes standards for the imposition of the conditions. Conditions imposed by a zone sponsor under this subsection shall be in addition to, and not in lieu of, conditions and requirements imposed under ORS 285B.650 to 285B.728 and shall not affect the duties of the Department of Revenue under ORS 285B.692 or of the county assessor under ORS 285B.695.

(5) A sponsor of an enterprise zone that imposes conditions for precertification on eligible business firms under subsection (4) of this section shall submit a written report every four years to the Legislative Assembly concerning the application and effects of such conditions on the eligible businesses within the enterprise zone. A report required by this subsection shall first be submitted to the Seventieth Legislative Assembly. [Formerly 285.577]

Note: See note under 285B.650.

285B.674 Availability of public property. Subject to the requirements of the Oregon Constitution and any applicable law, the State of Oregon and municipal corporations that own any real property within an enterprise zone that is zoned for use by eligible businesses and that is not used or designated for some public purpose shall make that real property available for lease or purchase by precertified or qualified business firms. Real property shall be leased or sold under this section only upon the condition that an eligible business firm promptly develop the real property for a use which has been precertified under ORS 285B.719. [Formerly 285.580]

Note: See note under 285B.650.

285B.677 Department as agency for state participation in federal enterprise zone program. (1) As used in this section, "federal enterprise zone" means any discrete area wholly or partially within this state that is designated as an empowerment zone, an enterprise community, a renewal community or some similar designation for purposes of improving the economic and community development of the area.

(2) The Economic and Community Development Department shall be the lead agency for state participation in a federal enterprise zone program. The Director of the Economic and Community Development Department may take action necessary for such participation to the extent allowed by state law.

(3) Any area designated as a federal enterprise zone by an agency of the federal government may be designated as a state enterprise zone by the director at the request of a city or county within whose jurisdiction some or all of the federal enterprise zone is located, without regard to any limitation contained in ORS 285B.656 (3) or 285B.662.

(4) The boundary of an existing state enterprise zone may be amended by the director at the request of the sponsor to include the entire area of a federal enterprise zone without regard to any limitation contained in ORS 285B.680 (2). A change in the boundary of an existing state enterprise zone under this subsection shall not change the termination date of the enterprise zone under ORS 285B.686 (3).

(5) A request by a city or county under subsection (3) or (4) of this section shall be in such form and include such information as required by the department, but the request must:

(a) Include a resolution adopted by the governing body of the city or county; and

(b) Provide that all areas within both the federal enterprise zone and the city or county are included in a state enterprise zone.

(6) The termination under federal law of a federal enterprise zone shall not affect the existence or dimensions of a state enterprise zone, except when, as determined by the director, the termination is for nonperformance or for violations of federal guidelines. [Formerly 285.583; 1999 c.460 s.7]

Note: See note under 285B.650.

285B.680 Change of zone boundaries. (1) The sponsor of an enterprise zone may submit a request to the Economic and Community Development Department to change the boundary of the enterprise zone. A request shall include:

(a) A resolution of the governing body of the sponsor requesting the change;

(b) A map clearly indicating the existing boundary and the proposed change thereto;

(c) A legal description of each area to be withdrawn from or added to the existing enterprise zone; and

(d) Other information required by the department.

(2) The amended enterprise zone shall:

(a) Add land zoned for use by eligible business firms:

(A) Which has or will have infrastructure facilities available; or

(B) Where road access exists or will be provided, water is or will be available on-site, sewage disposal is or will be provided on-site and necessary utility services are or will be provided;

(b) Continue to include any precertified or qualified business firms within the enterprise zone;

(c) Add residential areas only if the level of economic hardship therein is at least as severe as the original enterprise zone;

(d) Retain at least 50 percent of the lands in the original enterprise zone;

(e) Consist of a total area of not more than 12 square miles in size. The area of the zone shall be calculated by excluding that portion of the zone which lies below the ordinary high water mark of a navigable body of water, and

any road, railroad, electric transmission line or pipeline rights of way that connect otherwise unconnected areas of an enterprise zone. Such areas shall not be more than five miles apart; and

(f) Have 12 miles or less as the greatest distance between any two points within a zone amended under this section.

(3) A request under subsection (1) of this section may include a proposal to:

(a) Remove residential areas or land not zoned or available for use by eligible business firms; or

(b) Change the name of the enterprise zone.

(4) The boundary of an urban enterprise zone shall not be modified to include land located outside a regional or metropolitan urban growth boundary.

(5) A request to modify the boundary of a nonurban enterprise zone to include land located outside an urban growth boundary shall satisfy the requirements of subsections (1) and (2) of this section and shall include such other criteria as the department may adopt by rule.

(6) If an area to be added to an enterprise zone is under the jurisdiction of a city or county that is not a sponsor of the enterprise zone, the governing body of that city or county shall submit a resolution requesting the change and that it become a sponsor. The resolution may include a binding proposal for enhanced local public services, local incentives or local regulatory flexibility to be effective within the portion of the enterprise zone to be under the jurisdiction of that city or county.

(7) The department shall review the request for a boundary change. If the request is incomplete or does not satisfy the requirements of this section, the department shall seek additional information as necessary or shall return the request to the sponsor. If the request is returned, the sponsor may submit a revised request at any time. If the request is complete and does satisfy the requirements of this section, the Director of the Economic and Community Development Department shall order a change in the boundary of an enterprise zone based on the request of the sponsor and specify the effective date of the boundary change, which shall not be earlier than the receipt of a completed request.

(8) A change in the boundary of an enterprise zone under this section shall not change the termination date of the enterprise zone under ORS 285B.686 (3). [Formerly 285.585]

Note: See note under 285B.650.

285B.683 Change in boundaries of nonurban enterprise zone. (1) Notwithstanding ORS 285B.656 (3) and 285B.680 (2)(e) and (f), a nonurban enterprise zone may be designated under ORS 285B.659 or 285B.689 or have its zone boundary changed under ORS 285B.680 so that:

(a) A separate area of the zone may be as far as 15 miles from another area of the zone, when the separate area is entirely contained within a sparsely populated county;

(b) The zone may have 20 or fewer miles as the greatest distance between any two points within the zone, when only a portion of the zone is contained within a sparsely populated county; or

(c) The zone may have 25 or fewer miles as the greatest distance between any two points within the zone, when the zone is entirely contained within a sparsely populated county or within two or more sparsely populated counties.

(2) If the population density of a county increases to more than 100 persons per square mile, any existing enterprise zone located wholly or partly within that county that was designated or that had its zone boundary changed under subsection (1) of this section shall continue to exist with that zone boundary until terminated or until a subsequent boundary change under ORS 285B.680. However, any subsequent boundary change under ORS 285B.680 shall not add an area to the zone that:

(a) Is a separate area farther than five miles from the nearest point on the existing boundary;

(b) Increases the distance between the two points in the zone that are the farthest apart; or

(c) Creates a new line of distance to the farthermost opposite point in the zone that is longer than the greatest distance between any two existing points in the zone.

(3) Subsection (2) of this section does not limit the maximum distance within an enterprise zone to less than what is otherwise specifically allowed under subsection (1) of this section or ORS 285B.677 or 285B.680.

(4) Nothing in this section allows an enterprise zone to be more than 12 square miles in total area except as provided under ORS 285B.677.

(5) As used in this section, “sparsely populated county” means a county with a density of 100 or fewer persons per square mile, based on the most recently available population figure for the county from the Portland State University Center for Population Research and Census. [1997 c.835 s.2]

Note: See note under 285B.650.

285B.686 Zone termination. (1) Enterprise zones designated under ORS 284.110 to 284.260 (1987 Replacement Part) by order of the Governor before October 3, 1989, are declared valid and shall continue to exist until terminated under this section.

(2) When the termination of an enterprise zone occurs under this section:

(a) The termination of the enterprise zone shall not affect the continuation of a qualified business firm's property tax exemption for which the firm qualified before the effective date of the termination of the enterprise zone.

(b) Notwithstanding ORS 285B.698 (5)(e) and 285B.719 (6), a business firm that is currently precertified or qualified in the enterprise zone shall be allowed until 10 years after the effective date of the termination of the enterprise zone to apply for precertification under ORS 285B.719 and subsequently for property tax exemptions under ORS 285B.722 for any qualified property that is located inside the former enterprise zone boundaries at the time of termination and entirely outside of the boundaries of any current enterprise zone. Construction, modification or installment of qualified property must commence prior to the end of an exemption of the precertified or qualified business firm under ORS 285B.698 or 285B.710 and be completed in accordance with ORS 285B.719 (5)(b) and (c). The precertified or qualified business firm must comply with the requirements under ORS 285B.692 to 285B.728 in effect at the time of the termination of the enterprise zone.

(c) Disqualification under ORS 285B.728 of an entire property tax exemption after the date of the termination of the enterprise zone shall prohibit and terminate all precertifications and qualifying property tax exemptions that would not otherwise be allowed except for paragraph (b) of this subsection. Such termination shall not result in repayment of property taxes exempted before the tax year in which the disqualification takes effect.

(3) An enterprise zone previously designated by order of the Governor or designated by the Director of the Economic and Community Development Department under ORS 285B.653, 285B.677 or 285B.689 shall terminate when 10 years plus that number of days necessary to delay the date of termination to the June 30 next following have elapsed since the enterprise zone was originally designated by order of the Governor or the director.

(4) An enterprise zone shall terminate prior to the time specified in subsection (3) of this section only as provided in subsection (5) or (6) of this section.

(5) The governing body of the sponsor may submit a resolution requesting termination of the enterprise zone to the Economic and Community Development Department. The sponsor shall provide copies of the resolution to the county assessor and the Department of Revenue. After receipt of the request, the director shall order termination of the enterprise zone and shall specify the effective date of such termination.

(6) If a sponsor is unable or unwilling to carry out its responsibilities under ORS 285B.671, the director shall order termination of the enterprise zone and shall specify the effective date of such termination. However, in the case of failure to provide enhanced local public services, local incentives or local regulatory flexibility included in the application for designation as an enterprise zone or in the resolution under ORS 285B.680 (6), termination is not required if the sponsor provides new enhanced local public services, local incentives or local regulatory flexibility that have similar value, as determined by the department, to precertified or qualified business firms. A sponsor may reduce the time within which it will provide enhanced local public services, local incentives and local regulatory flexibility to a time period equal to the amount of time allowed for an exemption under ORS 285B.698 or 285B.710, without causing termination under this section. [Formerly 285.587]

Note: Section 4, chapter 1104, Oregon Laws 1999, provides:

Sec. 4. Notwithstanding ORS 285B.686 (2)(b), sections 2 [285B.723] and 3c of this 1999 Act and the amendments to ORS 285B.701 and 285B.704 by sections 3 and 3a of this 1999 Act are effective for any exemption granted under ORS 285B.650 to 285B.728. [1999 c.1104 s.4]

Note: See note under 285B.650.

285B.689 Designation of new zones after termination. (1) Within a reasonable period of time prior to the termination of enterprise zones under ORS 285B.686 (3), the Director of the Economic and Community Development Department shall competitively designate the same number of enterprise zones effective immediately after termination of the previous enterprise zones. The determination by the director as to the areas designated as enterprise zones shall be final.

(2) When an enterprise zone is terminated under ORS 285B.686 (5) or (6), the director may competitively

designate a new enterprise zone. The sponsor of the enterprise zone terminated under ORS 285B.686 (5) or (6) is not eligible to apply for a new enterprise zone, except for a county government when the terminated zone was also jointly sponsored by one or more cities.

(3) Sponsors of existing enterprise zones are eligible to reapply for designation under subsection (1) of this section.

(4) Any city or county may apply to the director for designation of an enterprise zone in accordance with the criteria set forth in ORS 285B.656 and 285B.662. In addition, the Economic and Community Development Department by rule shall determine the minimum level of economic hardship in any area to be included within an enterprise zone, any other criteria necessary to evaluate the need for the enterprise zone and the potential for accomplishing the purposes of ORS 285B.650 to 285B.728.

(5) All enterprise zones designated under this section shall terminate in accordance with ORS 285B.686 (3).

(6) When the director designates enterprise zones under this section, there is no limit on the relative number of urban or nonurban enterprise zones designated.

(7) The director may determine when to accept applications for any enterprise zone that terminates under subsection (2) of this section or is not designated under subsection (1) of this section for lack of qualified applicants. [Formerly 285.588]

Note: See note under 285B.650.

(Tax Exemptions)

Note: Sections 3c and 4a, chapter 1104, Oregon Laws 1999, provide:

Sec. 3c. (1) If an eligible business firm completes an investment of $25 million or more in the enterprise zone in qualified property confined entirely within an established operating division of the firm that would be an eligible business firm if it were separately incorporated, the firm may elect to have the division treated as a separate eligible business firm for purposes of applicable requirements under ORS 285B.692 to 285B.728. The election described in this subsection may only be made with respect to an application for the exemption of qualified property under ORS 285B.722 that was filed on or before January 1, 1999.

(2) For purposes of ORS 285B.704 (2) or (3), if the eligible business firm makes a total investment in the enterprise zone of $50 million or more in qualified property that initially qualifies for not more than three consecutive years, the governing body of the sponsor may also provide for one or more of the following as documented in the resolution under ORS 285B.704:

(a) That, notwithstanding ORS 285B.701 (3) or 285B.719 (1), this subsection and the application for precertification includes qualified property in the zone, for which construction, modification or installation commenced prior to the application, if the firm is precertified prior to use or occupancy of the qualified property;

(b) That the exemption shall be granted without regard to the cost of any portion of the investment that initially qualifies in any single year; or

(c) That the firm is not bound by any election under subsection (1) of this section or ORS 285B.707 (5) in effect at the time at which the zone terminated, in the case of a precertification and exemption that is otherwise allowed under ORS 285B.686 (2). [1999 c.1104 s.3c]

Sec. 4a. Section 3c of this 1999 Act is repealed on December 31, 2005. [1999 c.1104 s.4a]

Note: Sections 36 to 40 and 42 to 44, chapter 835, Oregon Laws 1997, provide:

Sec. 36. As used in sections 36 to 40, chapter 835, Oregon Laws 1997:

(1) "County with chronically low income or chronic unemployment" means, based on the most recently revised annual average unemployment rate or annual per capita income levels available, a county in which:

(a) The median ratio of the per capita personal income of the county to the equivalent annual personal income figure of the entire United States for each year, as reported by the Bureau of Economic Analysis of the United States Department of Commerce, is equal to or less than 0.75 over the last 10 years;

(b) Both of the following criteria are satisfied:

(A) The median ratio of the unemployment rate of the county to the equivalent rate of the entire United States for each year is at least 1.3 over the last 20 years or over the last 10 years; and

(B) The current unemployment rate of the county is at least one percentage point higher than the unemployment rate of the county for the immediately prior year or at least 50 percent higher than the current unemployment rate of this state; or

(c) The population of the county has experienced a negative net migration, irrespective of natural population change, since the most recent federal decennial census occurring three or more years prior to the current estimated population figure for the county, based on available population statistics.

(2) "Nonurban enterprise zone" has the meaning given that term in ORS 285B.650.

(3) "Taxing unit" means the State of Oregon or any county, city, municipal corporation, district or other government unit that has the power to tax. [1997 c.835 s.36; 1999 c.1104 s.10]

Sec. 37. (1) Any business firm proposing to apply for the tax exemption provided under section 38 (1), chapter 835, Oregon Laws 1997, shall, before the commencement of construction or installation of property or improvements at a facility in a nonurban enterprise zone and before the hiring of employees, apply for certification with the sponsor of the zone and with the county assessor of the county or counties in which the zone is located. The application shall be made on a form prescribed by the Department of Revenue.

(2) The application shall contain the following information:

(a) A description of the firm's business operations and facility in the nonurban enterprise zone;

(b) A description and estimated cost or value of the property or improvements to be constructed or installed at the facility in the nonurban enterprise zone;

(c) An estimate of the number of employees at the facility that will be hired by the firm;

(d) A commitment to meet all requirements of subsection (8) of this section;

(e) A commitment to satisfy all additional conditions for certification that are imposed by the nonurban enterprise zone sponsor under subsection (3)(c) of this section; and

(f) Any other information considered necessary by the Department of Revenue.

(3) The sponsor and the county assessor shall certify the business firm by approving the application if the sponsor and the county assessor determine that:

(a) The governing body of the county and city in which the facility is located has adopted a resolution approving the property tax exemption for the facility;

(b) The business firm has committed to meet the requirements of subsection (8) of this section;

(c) The business firm has entered into a written agreement with the sponsor of the nonurban enterprise zone that may include any additional requirements that the sponsor may reasonably request, including but not limited to contributions for local services or infrastructure benefiting the facility; and

(d) The facility is located in a county with chronically low income or chronic unemployment, based on the most recently revised annual data available when the written agreement with the zone sponsor is entered into.

(4) The approval of an application by both the sponsor and the county assessor under subsection (3) of this section shall be prima facie evidence that the business firm will be qualified for the property tax exemption under section 38 (1) and (2), chapter 835, Oregon Laws 1997.

(5) The sponsor or the county assessor shall not be liable in any way if it is determined that the certified business firm has not satisfied the requirements of subsection (8) of this section.

(6) The sponsor and the county assessor shall provide copies of an approved application to the applicant, the Department of Revenue and the Economic and Community Development Department.

(7) If the sponsor or the county assessor fails or refuses to certify the business firm, the business firm may appeal to the Oregon Tax Court under ORS 305.404 to 305.560. The business firm shall provide copies of the firm's appeal to the sponsor, the county assessor, the Economic and Community Development Department and the Department of Revenue.

(8) A business firm shall receive a property tax exemption from the county assessor under section 38 (1), chapter 835, Oregon Laws 1997, for property and improvements at a facility in a nonurban enterprise zone if, except as allowed under section 15 (1), (2) or (3) or section 17 (1) of this 1999 Act, all of the following conditions are met:

(a) By the end of the calendar year in which the facility is placed in service, the total costs of property and improvements at the facility after certification are or will be more than the lesser of:

(A) $50 million; or

(B) A figure equal to one percent of the value of all nonexempt taxable property in the county in which the facility is located, as reported by the Department of Revenue as net real market value at the time that the business firm is certified, and rounded to the nearest $10 million of such value.

(b) The business firm hires or will hire at least 75 full-time employees at the facility by the end of the fifth calendar year following the year in which the facility is placed in service. Unless the decrease in the number of employees is caused by circumstances beyond the taxpayer's control, including force majeure, or is due to a temporary adverse business cycle, after the number of employees required by this paragraph are hired, the number of employees shall not fall below 75.

(c) The annual average compensation for employees, based on payroll, at the business firm's facility is at least 150 percent of the average wage in the county in which the facility is located. This one-time requirement may be met in any year during the first five years after the year in which operation of the facility begins. Unless the decrease in the average compensation is caused by circumstances beyond the taxpayer's control, including force majeure, the average compensation at the taxpayer's facility shall not decrease to less than 150 percent of the average wage in the county in which the taxpayer's facility is located, as determined for the year in which the one-time requirement was met.

(9) Upon meeting the requirements set forth in subsection (8) of this section, the business firm shall notify the county assessor in writing that the requirements of subsection (8) of this section have been met.

(10) The county assessor, for each tax year that the property at the facility is exempt from taxation under section 38 (1) or (2), chapter 835, Oregon Laws 1997, shall:

(a) Enter on the assessment roll, as a notation, the real market value and assessed value of the property as if it were not exempt under section 38 (1) or (2), chapter 835, Oregon Laws 1997.

(b) Enter on the assessment and the tax roll, as a notation, the amount of taxes that would be due if the property were not exempt.

(c) Indicate on the assessment and tax roll that the property is exempt and is subject to potential additional taxes as provided in section 39, chapter 835, Oregon Laws 1997, by adding the notation “enterprise zone exemption (potential additional tax).” [1997 c.835 s.37; 1999 c.1104 s.11]

Sec. 38. (1) All of the property and improvements at the facility of a certified business firm shall be exempt from ad valorem taxation if the facility satisfies the requirements of section 37 (8), chapter 835, Oregon Laws 1997. The exemption allowed under this subsection shall first apply to the ad valorem tax year immediately following the tax year in which the business firm's facility is placed in service.

(2) Prior to the ad valorem tax year specified in subsection (1) of this section, no ad valorem taxes shall be imposed by a taxing unit on or with respect to the facility site and any property thereon owned or leased by the taxpayer, beginning in the tax year that begins in the first calendar year after which the business firm is certified or after which construction or reconstruction of the facility commences, whichever event occurs later.

(3) Any exemption allowed under subsection (1) or (2) of this section shall be 100 percent of the assessed value of the property and improvements at the facility in each of the tax years for which the exemption is available.

(4) The exemption allowed under subsection (1) of this section is available for a period of at least 7 but not more than 15 consecutive tax years, as determined in the written agreement between the business firm and the enterprise zone sponsor under section 37 (3)(c), chapter 835, Oregon Laws 1997.

(5) An exemption allowed under subsection (1) or (2) of this section shall not be allowed for real or personal property that has received a property tax exemption under ORS 285B.698. [1997 c.835 s.38; 1999 c.1104 s.12]

Sec. 39. If a business firm that is certified under section 37, chapter 835, Oregon Laws 1997, does not begin operations or is not reasonably expected to begin operations, as determined by the county assessor consistent with criteria established by rule of the Department of Revenue, or fails to meet the minimum requirements set forth in section 37 (8), chapter 835, Oregon Laws 1997, while receiving an exemption under section 38 (1) or (2), chapter 835, Oregon Laws 1997, the exemption shall terminate on July 1 following the then current tax year and there shall be added to the tax extended against the property on the next general property tax roll, to be collected and distributed in the same manner as the remainder of ad valorem property taxes, an amount equal to the difference between the taxes assessed against the property and improvements and the taxes that would otherwise have been assessed against the property and improvements for each of the consecutive tax years referred to in section 38 (4), chapter 835, Oregon Laws 1997, (or a lesser number of applicable years) and for any tax years under section 38 (2), chapter 835, Oregon Laws 1997, prior to the termination of the exemption under this section. [1997 c.835 s.39; 1999 c.1104 s.13]

Sec. 40. (1) Notwithstanding any law under which a taxing unit may levy or impose any ad valorem taxes on or with respect to a taxpayer located in a nonurban enterprise zone, a taxpayer that is a subchapter C corporation for federal income tax purposes and that owns or leases and is operating a facility in a nonurban enterprise zone that is

exempt from ad valorem property taxes under section 38 (1), chapter 835, Oregon Laws 1997, is entitled to tax credits for each tax year that are equal to 62.5 percent of the taxpayer's payroll and employee benefit costs, including but not limited to workers' compensation insurance and payroll taxes, of the facility for a period of at least 5 but not more than 15 consecutive tax years, as set forth and approved in writing by the Governor.

(2) The 5- to 15-year period referred to in subsection (1) of this section may begin in any tax year designated by the taxpayer in writing to the Department of Revenue, but shall not begin later than the third calendar year after the year in which the taxpayer begins operation of the facility. The entitlement of the taxpayer to the tax credits allowed under this section is not jeopardized solely because the 5- to 15-year period extends beyond the conclusion of the exemption period under section 38 (4), chapter 835, Oregon Laws 1997, if the requirements of section 37 (8), chapter 835, Oregon Laws 1997, continue to be satisfied.

(3) The tax credits authorized by this section may be used in each year during the 5- to 15-year period referred to in subsection (1) of this section to offset any corporate excise taxes, corporate income taxes, gross receipts taxes, sales and use taxes, except vehicle and vehicular fuel taxes, or any other similar taxes levied or imposed by the State of Oregon relating to the facility.

(4) Unless the facility is disqualified under section 39, chapter 835, Oregon Laws 1997, any tax credits allowable under this section during the 5- to 15-year period referred to in subsection (1) of this section that are not used by the taxpayer in a particular tax year during such 5- to 15-year period may be carried forward and used by the taxpayer for a period of five years after the end of the 5- to 15-year period referred to in subsection (1) of this section.

(5) Notwithstanding subsections (3) and (4) of this section:

(a) Tax credits allowable under this section may not be used to offset the first $1 million, or a lesser amount that is allowed under section 15 (4) of this 1999 Act, of corporate excise or income taxes paid by the corporation to this state in any taxable year. The first $1 million paid or any lesser amount that is allowed and paid includes taxes generally attributable to operations of the taxpayer throughout this state.

(b) The Department of Revenue shall distribute annually 30 percent of the taxpayer's annual tax payment of corporate or income taxes to the enterprise zone sponsor and other taxing districts, beginning in the first year for which a tax credit allowable under this section is claimed, and continuing either until the end of the period of five years under subsection (4) of this section, or until no unused tax credit is claimed in a year during that period.

(c) Following distribution to the enterprise zone sponsor and other taxing districts of 30 percent of the first $1 million or any lesser amount that is allowed of corporate income or excise taxes paid, further distribution under paragraph (b) of this subsection shall be limited to 30 percent of the corporation's annual payment of income or excise taxes relating to the facility, if any, that remain following exhaustion of any tax credit allowable and claimed under this section.

(d) The 30 percent of annual tax payment to be distributed under this subsection shall not be considered a part of the budget of the General Fund and shall be held separate and apart from the general tax collections of this state in a suspense account established under ORS 293.445 pending the actual distribution to the zone sponsor and other taxing districts.

(e) For purposes of this subsection, tax credits, other than those allowable under this section:

(A) Are not considered payments; and

(B) May not be used to offset the first $1 million or any lesser amount that is allowed of the corporation's income or excise taxes paid, or any such taxes paid relating to the facility, in any taxable year in which tax credits allowable under this section are claimed.

(6) Notwithstanding subsections (1) to (5) of this section, a taxing unit shall not levy or impose any taxes described in subsection (3) of this section on or with respect to a facility of the taxpayer, or the production therefrom, until the taxable year after the tax year in which the taxpayer's facility is placed into service.

(7) The tax credits allowed under this section are not in lieu of any deductions for depreciation or amortization, for payment of wages or other employee costs or for any other costs or expenses to which the corporation is entitled.

(8) The tax credits allowed under this section may not be transferred to another taxpayer.

(9)(a) For the purposes of calculating corporate income or excise taxes for the tax credits allowed under this section, “income or excise taxes relating to the facility” means income or excise taxes directly attributable to the qualifying facility and its operations at the facility site without regard to the existence of other operations or facilities of the taxpayer, whether within or outside this state.

(b) If the qualifying facility is the only property or operation of the taxpayer within this state, all Oregon income or excise taxes of the taxpayer are income or excise taxes relating to the facility.

(c) If the taxpayer maintains other Oregon property or operations in addition to the qualifying facility, income or

excise taxes relating to the facility are determined by multiplying the total Oregon income or excise taxes by a fraction, the numerator of which is the income of the facility, as determined in accordance with generally accepted accounting principles and reviewed by an independent public accountant in accordance with Statements on Standards for Accounting and Review Services issued by the American Institute of Certified Public Accountants, and the denominator of which is the total Oregon income, as determined in accordance with generally accepted accounting principles and reviewed by an independent public accountant in accordance with Statements on Standards for Accounting and Review Services issued by the American Institute of Certified Public Accountants. If no such data are prepared in accordance with generally accepted accounting principles and reviewed by an independent public accountant in accordance with Statements on Standards for Accounting and Review Services issued by the American Institute of Certified Public Accountants, income or excise taxes are apportioned to the qualifying facility by multiplying the total Oregon income or excise taxes by a fraction, the numerator of which is the sum of the intrastate payroll factor plus the intrastate property factor and the denominator of which is two.

(d) The intrastate payroll factor is a fraction, the numerator of which is the total amount paid for compensation at the qualifying facility during the tax period and the denominator of which is the total amount of compensation paid in Oregon during the tax period.

(e) The intrastate property factor is a fraction, the numerator of which is the average net book value of the real and tangible personal property owned or rented and located at the qualifying facility during the tax period and the denominator of which is the average net book value of the real and tangible personal property owned or rented by the taxpayer in Oregon during the tax period. The average net book value of real and tangible personal property shall be determined using generally accepted accounting principles.

(10)(a) The annual distribution to the enterprise zone sponsor and other taxing districts under subsection (5) of this section of 30 percent of corporate income or excise taxes paid by the corporation to this state shall be distributed by the Department of Revenue to each county treasurer in a single payment for each facility.

(b) If the facility is situated in more than one code area, the county treasurer shall allocate payments to each code area based on the ratio of the real market value of the facility in each code area over the total real market value of the facility in all of the code areas.

(c) The county treasurer shall distribute the moneys allocated to each code area to the taxing districts located within the code area based on the ratio of the operating tax billing rate that each taxing district bears to the total operating tax billing rate of the taxing districts located in the code area as calculated on the most recent tax roll certified under ORS 311.105. However, the distribution to any taxing district under this paragraph may not exceed the amount of property taxes that the district had forgone in the current ad valorem tax year as a result of an exemption on the facility under section 38 (1), chapter 835, Oregon Laws 1997.

(d) If the distribution to taxing districts under paragraph (c) of this subsection is less than the total amount distributed by the Department of Revenue in the current year under paragraph (a) of this subsection, the remainder shall be distributed by the county treasurer to the zone sponsor.

(e) The county treasurer shall distribute moneys under this subsection to taxing districts in a separate distribution within 90 days of receipt or completion of the applicable assessment and tax roll under section 37 (10), chapter 835, Oregon Laws 1997, whichever occurs later.

(f) For purposes of this subsection, a school district, an education service district or a community college district shall not be considered a taxing district. [1997 c.835 s.40; 1999 c.1104 s.14]

Sec. 42. Sections 36, 37, 38, 39 and 40 of this Act are repealed on December 31, 2002. [1997 c.835 s.42]

Sec. 43. Notwithstanding section 42 of this Act, any taxpayer that qualifies for the tax exemptions and tax credits provided for in sections 36 to 40 of this Act prior to December 31, 2002, may continue to receive and use the tax exemptions and tax credits allowed under sections 36 to 40 of this Act after that date as if sections 36 to 40 of this Act had not been repealed. [1997 c.835 s.43]

Sec. 44. (1) Notwithstanding ORS 285B.698 (3) and (5)(c) and 285B.722 (1), if a business firm does not qualify under ORS 285B.704 for a property tax exemption on qualified property solely because the business firm failed to file the application for exemption prior to April 1 of the assessment year for which the exemption is first sought, the business firm may submit an application for tax exemption for the qualified property to the county assessor on or before December 31 of the same assessment year. If the business firm meets the applicable requirements of ORS 285B.698, 285B.701, 285B.704, 285B.707, 285B.710, 285B.713, 285B.716, 285B.719, 285B.722 and 285B.728:

(a) The business firm shall qualify for the remainder of the exemption period that was otherwise available under ORS 285B.698 or 285B.710; and

(b) The county assessor shall take action under ORS 285B.722 (4) that is necessary to allow the qualified property to be exempted from property taxation for the remaining tax years that were otherwise available for exemption under ORS 285B.698 or 285B.710 after the first tax year, regardless of the prior entry of the qualified property on the county assessment roll.

(2) Nothing in this section exempts from ad valorem taxation:

(a) The qualified property in tax years other than those specified in subsection (1)(b) of this section;

(b) Any property that does not meet the requirements of subsection (1) of this section; or

(c) Any qualified property that was in use or occupancy within the enterprise zone for more than 12 months by December 31 preceding the assessment year in which the application for exemption is submitted under subsection (1) of this section.

(3) If the qualified property is leased by the business firm, the owner of the qualified property leased by the business firm shall also join in the application submitted under subsection (1) of this section.

(4) An application may be submitted under subsection (1) of this section regardless of there being grounds for hardship as required for late filing under ORS 307.475. [1997 c.835 s.44; 1999 c.1104 s.19]

Note: Sections 15 to 18, 20, 23, 26 and 27, chapter 1104, Oregon Laws 1999, provide:

Sec. 20. Section 44, chapter 835, Oregon Laws 1997, operates in lieu of section 34, chapter 835, Oregon Laws 1997, for assessment years beginning on or after January 1, 1998. [1999 c.1104 s.20]

Sec. 26. Section 44, chapter 835, Oregon Laws 1997, is repealed on June 30, 2009. [1999 c.1104 s.26]

Sec. 15. (1) Notwithstanding section 37 (8)(b), chapter 835, Oregon Laws 1997, or subsection (2)(b) of this section, the facility of a certified business firm that otherwise meets the requirements of sections 36 to 40, chapter 835, Oregon Laws 1997, shall receive the exemption under section 38 (1), chapter 835, Oregon Laws 1997, if:

(a) The business firm hires or will hire at least 10 full-time employees at the facility by the end of the third calendar year following the year in which the facility is placed in service, and at the time that the business firm is certified, the location of the facility is in a county with a currently estimated population of 10,000 or less; or

(b) The business firm hires or will hire at least 35 full-time employees at the facility by the end of the third calendar year following the year in which the facility is placed in service, and at the time that the business firm is certified, the location of the facility is in a county with a currently estimated population of 40,000 or less.

(2) Notwithstanding section 37 (8)(a) or (b), chapter 835, Oregon Laws 1997, the facility of a certified business firm that otherwise meets the requirements of sections 36 to 40, chapter 835, Oregon Laws 1997, shall receive the exemption under section 38 (1), chapter 835, Oregon Laws 1997, if:

(a) By the end of the calendar year in which the facility is placed in service, the total costs of improvements and property at the facility are or will be equal to more than one-half of one percent of the value of all nonexempt taxable property in the county in which the facility is located, as reported by the Department of Revenue as net real market value at the time that the business firm is certified and rounded to the nearest $10 million of such value;

(b) The business firm hires or will hire at least 50 full-time employees at the facility by the end of the third calendar year following the year in which the facility is placed in service; and

(c) At the time that the business firm is certified, the location of the facility is 10 or more miles from Interstate Highway 5, as measured between the two closest points between the facility site and anywhere along that interstate highway.

(3) Unless the decrease in the number of employees is caused by circumstances beyond the control of the business firm, including force majeure, or is due to a temporary adverse business cycle, after the number of employees required by subsection (1)(a) or (b) or (2)(b) of this section are hired, the number of employees at the facility shall not fall below the required level, for purposes of section 39, chapter 835, Oregon Laws 1997.

(4) A taxpayer that is a subchapter C corporation for federal income tax purposes and that owns or leases and is operating a facility in a nonurban enterprise zone that is exempt from ad valorem taxation under section 38 (1), chapter 835, Oregon Laws 1997, pursuant to subsection (1), (2) or (3) of this section, is entitled to the tax credits in accordance with the provisions of section 40, chapter 835, Oregon Laws 1997, except that for purposes of section 40 (5), chapter 835, Oregon Laws 1997, the minimum of corporate excise or income taxes paid by the corporation to this

state that may not be offset by the tax credits shall be the lesser of the first $1 million or one of the following products, whichever is applicable:

(a) $10,000 multiplied by the number of full-time employees hired at the facility as initially verified by the business firm or by the number of such employees as subsequently verified, if necessary, for purposes of subsection (3) of this section, for a facility receiving the exemption as provided under subsection (1)(a) of this section;

(b) $12,500 multiplied by the number of full-time employees hired at the facility as initially verified by the business firm or by the number of such employees as subsequently verified, if necessary, for purposes of subsection (3) of this section, for a facility receiving the exemption as provided under subsection (1)(b) of this section; or

(c) $15,000 multiplied by the number of full-time employees hired at the facility as initially verified by the business firm or by the number of such employees as subsequently verified, if necessary, for purposes of subsection (3) of this section, for a facility receiving the exemption as provided under subsection (2) of this section.

(5) For purposes of subsection (4) of this section, the business firm may not begin to use the tax credits in accordance with section 40 (2), chapter 835, Oregon Laws 1997, until the firm has initially verified the number of employees hired at the facility to the satisfaction of the county assessor and the Department of Revenue, and any change in the relevant product shall apply to each tax year beginning after the subsequent verification. [1999 c.1104 s.15]

Sec. 16. Section 15 of this 1999 Act is applicable to any business firm certified under section 37, chapter 835, Oregon Laws 1997, after the effective date of this 1999 Act [October 23, 1999]. A business firm or facility that satisfies the applicable requirements of section 15 of this 1999 Act shall be considered to have satisfied the corresponding requirements of section 37 (8), chapter 835, Oregon Laws 1997, as modified under section 15 (1), (2) or (3) of this 1999 Act. [1999 c.1104 s.16]

Sec. 17. (1) Notwithstanding section 37 (8)(a) and (b), chapter 835, Oregon Laws 1997, the facility of a certified business firm that otherwise meets the requirements of sections 36 to 40, chapter 835, Oregon Laws 1997, shall receive the exemption under section 38 (1), chapter 835, Oregon Laws 1997, if:

(a) Within three years either before or after the ad valorem tax year in which the facility is placed in service, the business firm places one or more other facilities in the same or another enterprise zone for which the business firm is certified and otherwise meets the requirements of sections 36 to 40, chapter 835, Oregon Laws 1997;

(b) The total cost of improvements and property at all such facilities are or will be more than $50 million by the end of the calendar year in which the last such facility is placed in service;

(c) The requirement of section 37 (8)(c), chapter 835, Oregon Laws 1997, is satisfied independently by each facility; and

(d) The business firm hires or will hire at least 100 full-time employees at all such facilities by the end of the fifth calendar year following the year in which the first such facility is placed in service. After 100 or more full-time employees are hired as required under this paragraph, the number of employees shall not fall below 100 unless the decrease in the number of employees is caused by circumstances beyond the control of the business firm, including force majeure, or is due to a temporary adverse business cycle.

(2) A taxpayer that is a subchapter C corporation for federal income tax purposes and that owns or leases and operates in a nonurban enterprise zone any facility that is exempt from ad valorem taxation under subsection (1) of this section is entitled to the tax credits under section 40, chapter 835, Oregon Laws 1997, insofar as the Governor's approval specifies the facility and the time period for which the tax credits apply. The tax credit for each tax year for each specified facility:

(a) Shall be calculated based on the taxpayer's total annual payroll and employee benefit costs at that facility; and

(b) May be used to offset only those taxes, as described in section 40 (3), chapter 835, Oregon Laws 1997, relating to that facility, consistent with section 40 (9), chapter 835, Oregon Laws 1997.

(3) If a taxpayer claims or may claim tax credits allowable under section 40, chapter 835, Oregon Laws 1997, for two or more facilities located in more than one nonurban enterprise zone, then the annual distribution to the enterprise zone sponsors and other taxing districts of 30 percent of the first $1 million of corporate income or excise taxes paid by the corporation to this state, under section 40 (5), chapter 835, Oregon Laws 1997, shall be distributed to each zone sponsor and other taxing districts in proportion to the relative size of the intrastate property factor among the facilities for that year under section 40 (9)(e), chapter 835, Oregon Laws 1997. [1999 c.1104 s.17]

Sec. 18. Section 17 of this 1999 Act applies to any business firm certified under section 37, chapter 835, Oregon

Laws 1997, during or after the 1999 assessment year. [1999 c.1104 s.18]

Sec. 27. Section 17 of this 1999 Act is repealed on December 31, 2002. [1999 c.1104 s.27]

Sec. 23. (1) Nothing in the amendments to sections 36, 37, 38, 39 and 40, chapter 835, Oregon Laws 1997, by sections 10, 11, 12, 13 and 14 of this 1999 Act affects the provisions of sections 42 and 43, chapter 835, Oregon Laws 1997.

(2) The amendments to sections 36, 37, 38, 39 and 40, chapter 835, Oregon Laws 1997, by sections 10, 11, 12, 13 and 14 of this 1999 Act apply to any tax exemptions or tax credits under sections 36 to 40, chapter 835, Oregon Laws 1997, except that the normal period for the exemption from ad valorem taxation under section 38 (1), chapter 835, Oregon Laws 1997, or for the tax credits allowed under section 40, chapter 835, Oregon Laws 1997, shall not be less than 15 years for a taxpayer that applied for certification under section 37 (1), chapter 835, Oregon Laws 1997, prior to the effective date of this 1999 Act [October 23, 1999]. [1999 c.1104 s.23]

285B.692 Duties of Department of Revenue. In addition to any other powers granted by law, for the purposes of ORS 285B.692 to 285B.728, the Department of Revenue shall:

(1) Adopt any rules the Department of Revenue considers necessary to implement ORS 285B.692, 285B.695, 285B.698, 285B.713, 285B.719, 285B.722, 285B.725 and 285B.728.

(2) Assist the Economic and Community Development Department, county assessors and the sponsors of enterprise zones in their efforts to precertify or qualify eligible business firms.

(3) Assist an eligible business firm doing business within an enterprise zone to obtain the benefits of applicable tax incentive or inducement programs administered or supervised by the Department of Revenue.

(4) Issue and print forms and worksheets to be used by eligible business firms applying for precertification or by precertified business firms applying for a property tax exemption under ORS 285B.719 or 285B.722.

(5) Submit a written report to the Economic and Community Development Department on or before January 15 in each year. The report shall include the number of jobs created and the value of investments in qualified property made by qualified business firms in the current tax year, and other information considered necessary by the Department of Revenue or required by the Economic and Community Development Department. [Formerly 285.593]

Note: See note under 285B.650.

285B.695 Duties of county assessor. The assessor of a county within which an enterprise zone is located shall:

(1) Assist the local zone manager and eligible or precertified business firms in determining whether property will qualify for a property tax exemption under ORS 285B.698 and 285B.713.

(2) Review and approve or deny applications from eligible business firms for precertification under ORS 285B.719.

(3) Process applications from precertified business firms for property tax exemptions under ORS 285B.722.

(4) Take action necessary under ORS 285B.728 if a business firm or property is no longer qualified for the property tax exemption.

(5) Submit a written report to the Department of Revenue on or before December 1 in each year. The report shall include the number of jobs created and the value of investments in qualified property made by qualified business firms in the current tax year, and other information considered necessary by the assessor or required by the Department of Revenue. The assessor shall provide copies of the report to the sponsors of enterprise zones located within the county and as directed by the Department of Revenue. [Formerly 285.595]

Note: See note under 285B.650.

285B.698 Property tax exemption. (1) Upon compliance with ORS 285B.722, qualified property of a qualified business firm shall be exempt from ad valorem property taxation, if:

(a) The qualified property was constructed, added to, modified or installed in furtherance of the production of income;

(b) The property or portion of the property for which exemption is sought was in use or occupancy no later than April 1 of the assessment year for which exemption is sought;

(c) The total cost of all of the qualified property for which application for exemption is made was at least $25,000;

and

(d) The property satisfies the requirements of ORS 285B.713.

(2) The exemption allowed under this section shall be allowed only for property that is owned or leased by a qualified business firm that satisfies the requirements of ORS 285B.704. If the property is leased by a qualified business firm, the qualified business firm must be required by the terms of the lease to pay or compensate the owner for the entire amount of property taxes assessed against the leased property during the lease term.

(3)(a) The exemption allowed under this section shall first apply to the assessment year immediately following completion of the construction, addition, modification or installation of the property. The exemption shall continue for the two succeeding assessment years if the property continues to be owned or leased by the qualified business firm and located in the enterprise zone.

(b) If qualified property of a qualified business firm is sold or leased to an eligible business firm in the enterprise zone during the period of abatement, the purchasing or leasing firm is eligible to continue the exemption of the selling or leasing firm for the balance of the abatement period, but only if any effects on employment within the zone that result from the sale or lease do not constitute substantial curtailment under ORS 285B.728 (3).

(4) The exemption allowed under this section shall be 100 percent of the assessed value of the qualified property in each of the tax years for which the exemption is available. If the qualified property is an addition to or modification of an existing building or structure, the exemption shall be measured by the increase in value, if any, attributable to the addition or modification.

(5)(a) No exemption shall be granted for property assessed for property tax purposes in the county in which the zone is located on or before the effective date of the:

(A) Designation of the zone; or

(B) Approval of a boundary change for the zone if the property is located in an area added to the zone.

(b) No exemption shall be granted for property constructed, added to, modified or installed in the zone or in the process of construction, addition, modification or installation in the zone on or before the effective date of the:

(A) Designation of the zone; or

(B) Approval of a boundary change for the zone if the property is located in an area added to the zone.

(c) No exemption shall be granted for any qualified property that was in use or occupancy within the zone for more than 12 months by December 31 preceding the first assessment year for which an application for exemption is made.

(d) No exemption shall be granted for any qualified property unless the property was in use or occupancy in the assessment year immediately following completion of construction, addition, modification or installation.

(e) Except as provided in ORS 285B.719 (6), no exemption shall be granted for qualified property constructed, modified or installed after termination of an enterprise zone.

(6) A qualified business firm may apply for a tax exemption for additional qualified property initially occupied or used during or after the first year in which a tax exemption for the firm's initial investment in qualified property was approved if the firm meets the applicable requirements of this section and ORS 285B.701, 285B.704, 285B.707, 285B.710, 285B.713, 285B.716, 285B.719 and 285B.722. [Formerly 285.597]

Note: See note under 285B.650.

285B.701 Exemption allowed for property constructed or modified for lease or sale to precertified business firm. (1) The Legislative Assembly finds that the standard procedure for precertification in an enterprise zone inappropriately deters development or redevelopment of qualified buildings on speculation for subsequent sale or lease to eligible business firms.

(2) Notwithstanding ORS 285B.719 (1), a new building or structure or an addition to or modification of an existing building or structure may qualify for the exemption allowed under ORS 285B.698 or 285B.710 if the qualified property is leased or sold by an unrelated party to one or more precertified business firms after commencement of the construction, addition or modification but prior to use or occupancy of the qualified property.

(3) For purposes of ORS 285B.722, a business firm shall not be considered precertified and is not qualified for the exemption allowed under ORS 285B.698 or 285B.710 if the county assessor discovers prior to initially granting the exemption that the application for precertification was not submitted by the business firm in a timely manner in accordance with ORS 285B.719 (1), except as allowed under subsection (2) of this section or ORS 285B.719 (8).

(4) Records, communications or information submitted to a public body by a business firm for purposes of ORS 285B.650 to 285B.728 that identify a particular qualified property, that reveal investment plans prior to precertification, that are described in ORS 192.502 (16) or that are submitted under ORS 285B.728 are exempt from

disclosure under ORS 192.410 to 192.505 and, as appropriate, shall be shared among the county assessor, the zone sponsor, the Department of Revenue and the Economic and Community Development Department. [Formerly 285.598; 1999 c.1104 s.3]

Note: See note under 285B.650.

285B.704 Qualifications for exemption. (1) A business firm is qualified to receive a property tax exemption under ORS 285B.698 for its qualified property only if:

(a) The firm is an eligible business firm described in ORS 285B.707;

(b) The firm has business operations located inside the enterprise zone;

(c) The firm owns or leases qualified property located inside the enterprise zone;

(d) The employment of the firm, no later than April 1 following the assessment year in which the investment in qualified property was completed, is not less than 110 percent of the average annual employment of the firm, calculated over the 12 months preceding the date of application for precertification;

(e) The firm hired at least one new employee to work within the enterprise zone, under paragraph (d) of this subsection, after precertification and no later than April 1 following the assessment year in which the investment in qualified property was completed;

(f) The firm satisfies the hiring requirements of ORS 285B.710 (1);

(g) The firm did not diminish employment outside the enterprise zone under subsection (4) of this section;

(h) The firm did not substantially curtail employment within the enterprise zone as described in ORS 285B.728;

(i) The firm complies in all material respects with local, Oregon and federal laws applicable to the firm's operations inside the enterprise zone since the application for precertification and throughout the period of exemption, as prescribed by rule; and

(j) The firm complies with all additional conditions for precertification imposed by an enterprise zone sponsor under ORS 285B.671 (4).

(2)(a) Notwithstanding subsection (1)(d), (e) or (h) of this section, an eligible business firm is a qualified business firm if it completes an investment of $25 million or more in qualified property, on or before December 31 preceding the first assessment year for which the exemption is being sought, with less than a 10 percent increase in employment of the firm but without loss of employment of the firm.

(b) Approval to extend the property tax benefit to the eligible business firm under this subsection shall be documented by resolution of the governing body of the sponsor. The resolution shall specify the minimum percentage increase in employment that the eligible business firm must maintain to be a qualified business firm throughout the exemption period. The resolution may include other conditions for the firm to be a qualified business firm. At the request of the eligible business firm, the sponsor may modify the resolution prior to the initial filing by the firm for the property tax exemption. A copy of the resolution shall be attached to the final applications for precertification and for the property tax exemption.

(3)(a) Notwithstanding subsection (1)(d), (e) or (h) of this section, with the approval of the sponsor of the enterprise zone, an eligible business firm is a qualified business firm if it completes an investment of $25 million or more in qualified property, on or before December 31 preceding the first assessment year for which the exemption is being sought, with a loss of employment of the firm.

(b) Approval to extend the property tax benefit to the eligible business firm under this subsection shall be documented by resolution of the governing body of the sponsor. The resolution shall specify the minimum number of employees that the firm must retain for the eligible business firm to be a qualified business firm throughout the exemption period. The resolution may include other conditions for the firm to be a qualified business firm. At the request of the eligible business firm, the sponsor may modify the resolution prior to the firm's initial filing for the property tax exemption. A copy of the resolution shall be attached to the firm's applications for precertification and for the property tax exemption.

(4) Notwithstanding subsections (1) to (3) of this section, a business firm is not qualified to receive a property tax exemption if the firm or any other firm under common control closes or permanently curtails operations in another part of the state more than 30 miles from the nearest boundary of the enterprise zone in which the firm seeks a property tax exemption. This subsection applies to the transfer of any of the business firm's operations to an enterprise zone from another part of the state, if the closure or permanent curtailment in the other part of the state diminished employment in the county and more local labor markets after precertification and before the initial application for the exemption.

(5) An eligible business firm that moves any of its employees from a site or sites within 30 miles from the nearest

boundary of the enterprise zone after precertification and before the initial application for the exemption may qualify to receive a property tax exemption only if the employment of the firm has been increased within the zone and at the site or sites from which the employees were transferred, no later than April 1 following the assessment year in which the investment in qualified property was completed, to not less than 110 percent of the average annual employment of the firm within the zone and the site or sites from which the employees were transferred, calculated over the 12 months preceding the date of application for precertification.

(6) As used in this section and except as provided in subsection (5) of this section, "employment of the firm" means the number of employees working for the firm a majority of their time in eligible operations at locations within the enterprise zone. [Formerly 285.600; 1999 c.1104 s.3a]

Note: See note under 285B.650.

285B.705 Effect on exemption of noncompliance with applicable laws; determination of noncompliance; rules. For purposes of ORS 285B.704 (1)(i), the Economic and Community Development Department shall adopt rules that, notwithstanding ORS 311.205, define the effect of noncompliance on an eligible business firm's continuing exemption in an enterprise zone and that indicate what is necessary to establish such noncompliance in terms of the materiality of the relevant violation, the finality of applicable legal or regulatory proceedings and judgments involving the firm, the failure by the firm to perform or submit to remedial or curative actions and similar factors. [1999 c.1104 s.4b]

Note: 285B.705 was enacted into law by the Legislative Assembly but was not added to or made a part of ORS chapter 285B or any series therein by legislative action. See Preface to Oregon Revised Statutes for further explanation.

285B.707 Eligibility. (1) Except as provided in subsections (3) and (4) of this section, to be an eligible business firm, a business firm must be engaged in the business of providing goods, products or services to other businesses, and not to the general public for personal or household use or consumption, through activities including, but not limited to, manufacturing, assembly, fabrication, processing, shipping or storage.

(2) Businesses significantly engaged in business activities within the enterprise zone such as retail sales or services, child care, housing, retail food service, health care, tourism, entertainment, financial services, professional services, leasing space to others, property management, construction or other similar activities are not eligible business firms.

(3) Notwithstanding subsection (1) or (2) of this section, a business firm that operates a hotel, motel or destination resort is an eligible business firm regardless of the sale of services for personal consumption, if allowed in the enterprise zone under ORS 285B.716.

(4) Notwithstanding any other provision of this section, if a business firm described in subsection (2) of this section engages in an activity described in subsection (1) of this section, the business firm is an eligible business firm if the activity is performed at a location that is separate from the activity of the firm that is described in subsection (2) of this section. For purposes of determining whether a business firm described in this subsection satisfies the requirements of ORS 285B.704, only the operations of the firm that are described in subsection (1) of this section and employees working a majority of their time in those operations shall be considered.

(5) Two or more business firms that otherwise meet the requirements of this section may elect to be treated as one eligible business firm if 100 percent of the equity interest in the business firms is owned by the same person or persons, or if one of the business firms owns 100 percent of the equity interest of the other or others.

(6) Notwithstanding subsection (1) or (2) of this section, a business firm engaged in the activity of providing a retail or financial service is an eligible business firm if:

(a) The activity serves customers by responding to orders or requests received only by telephone, computer, the Internet or similar means of telecommunications; and

(b) Not less than 90 percent of the customers or orders are located and originate in an area from which long distance telephone charges, in the absence of a toll-free number, would apply if the order were placed by telephone.

(7) Notwithstanding subsection (1) or (2) of this section, a business firm that makes an investment in qualified property at a facility that serves statewide, regional, national or global operations of the firm through administrative, design, financial, management, marketing or other activities is an eligible business firm, without regard to the relationship of such activities to any otherwise eligible activities within the enterprise zone if:

(a) In approving the application for precertification, the zone sponsor includes with the application a formal finding

that the facility complies with the requirements of this subsection and that the size of the proposed investment, the employment at the facility or the nature of the activities at the facility will significantly enhance the local economy, in relation to the overall purpose and employment of the zone;

(b) The actual investment and facility of the firm are consistent with the descriptions presented in the precertification application; and

(c) For purposes of ORS 285B.704, all employees at the facility constitute employment of the firm, as defined in ORS 285B.704. [Formerly 285.603; 1999 c.1104 s.5]

Note: See note under 285B.650.

285B.710 First-source hiring agreement; hiring requirements in urban zones; extended period of tax abatement. (1) A precertified business firm shall enter into a first-source hiring agreement with a publicly funded job training provider for the period of property tax exemption.

(2) If a qualified business firm is located in an urban enterprise zone inside a metropolitan statistical area with fewer than 400,000 residents, all new employees hired by the firm must meet all additional conditions imposed under ORS 285B.671 (4).

(3) Notwithstanding ORS 285B.698 (3)(a), if a firm is located in an urban enterprise zone situated inside a metropolitan statistical area of less than 400,000 residents, the sponsor may set a period of abatement of up to five consecutive assessment years if the qualified business firm agrees with the sponsor, in writing, at the time of precertification:

(a) To annually compensate all new employees hired by the firm at an average rate of not less than 150 percent of the county's average annual wage until the end of the tax exemption period. If the zone is in more than one county, the county with the highest average annual wage shall be used; and

(b) To meet any additional requirements that the zone sponsor may reasonably request.

(4) Notwithstanding ORS 285B.698 (3)(a), if an urban enterprise zone is located inside a metropolitan statistical area with more than 400,000 residents, the sponsor may set a longer period of abatement that does not exceed five consecutive assessment years if the qualified business firm agrees with the sponsor, in writing at the time of precertification, to meet any additional requirements that the zone sponsor may reasonably request.

(5) If a firm is located in an urban enterprise zone situated inside a metropolitan statistical area of more than 400,000 residents, all new employees hired by the firm must meet all additional conditions imposed under ORS 285B.671 (4).

(6) Notwithstanding ORS 285B.698 (3)(a), if a firm is located in a nonurban enterprise zone, the sponsor may set a period of abatement up to five consecutive assessment years if the qualified business firm agrees with the sponsor, in writing, at the time of precertification:

(a) To annually compensate all new employees hired by the firm at an average rate of not less than 150 percent of the county's average annual wage until the end of the tax exemption period. If the zone is in more than one county, the county with the highest average annual wage shall be used; and

(b) To meet any additional requirements which the zone sponsor may reasonably request.

(7) As used in this section, “new employees hired by the firm” includes only those employees engaged for a majority of their time in eligible operations. The term does not include individuals employed in a job or position that:

(a) Is filled for the first time after June 30 of the first tax year of the exemption;

(b) Existed prior to the submission of the relevant application for precertification; or

(c) Is performed primarily at locations outside the enterprise zone. [Formerly 285.605]

Note: See note under 285B.650.

285B.713 Qualified property. (1) The property tax exemption provided under ORS 285B.698 shall be available only for qualified property of a qualified business firm.

(2) The following kinds of property are qualified for the exemption allowed under ORS 285B.698:

(a) A new building or structure with a cost of $25,000 or more.

(b) An addition to or modification of an existing building or structure. The total cost of qualifying additions or modifications to an existing building or structure shall be at least $25,000 in one assessment year. In order to satisfy the minimum investment requirement, the cost of two or more additions or modifications made in one assessment year to a single building or structure may be aggregated.

(c) Any real property machinery or equipment, whether new, used or reconditioned, that is newly purchased, leased or transferred into the enterprise zone from outside the county within which the zone is located and installed in property owned or leased by a qualified business firm.

(d) Any single item of personal property machinery or equipment, whether new, used or reconditioned, that is newly purchased, leased or transferred into the enterprise zone from outside the county within which the zone is located and installed in property owned or leased by a qualified business firm and:

(A) That has a cost of at least $1,000 if the property is used exclusively for producing tangible goods; or

(B) That has a cost of at least $50,000.

(e) A new building and associated structures owned by a governmental body that are leased to one or more qualified business firms.

(f) Any property otherwise described in this section that is owned or leased and operated by a business firm operating a hotel, motel or destination resort, to the extent that the property is located on the same site as the hotel, motel or destination resort and is used primarily to serve overnight guests of the hotel, motel or destination resort. For purposes of this paragraph, property is primarily used to serve guests if at least 50 percent of any receipts from such use are paid by guests.

(g) Any property otherwise described in this section that is owned or leased and operated by a business firm described in ORS 285B.707 (4), to the extent that the property is used exclusively in an activity described in ORS 285B.707 (1).

(3) The following property is not qualified for exemption under ORS 285B.698:

(a) Land.

(b) Self-propelled motorized vehicles.

(c) Property excluded under ORS 285B.698 (5). [Formerly 285.607]

Note: See note under 285B.650.

285B.716 When exemption available to hotel, motel or destination resort property. (1) Qualified property owned or leased and operated by a business firm as a hotel, motel or destination resort, including property described in ORS 285B.713 (2)(f), may not receive an exemption under ORS 285B.722, unless:

(a) The business firm that operates the hotel, motel or destination resort is precertified by the sponsor on or before June 30, 1996, under ORS 285B.719 and the sponsor notified the Department of Revenue on or before December 1, 1989, of the sponsor's desire to exempt hotel, motel and destination resort property;

(b) The business firm that operates the hotel, motel or destination resort is precertified by the sponsor after June 30, 1996, under ORS 285B.719, and the sponsor notifies the Economic and Community Development Department and the Department of Revenue in writing on or before June 1, 1996, of the sponsor's desire to exempt hotel, motel and destination resort property; or

(c) The business firm that operates the hotel, motel or destination resort is precertified under ORS 285B.719 not less than 30 days after notification to the Economic and Community Development Department and the Department of Revenue of the desire of the sponsor to exempt hotel, motel and destination resort property, as documented by a resolution adopted by the governing body of the sponsor not later than December 31, 1997.

(2) Only if a zone sponsor exercises its option pursuant to the notification procedures set forth in subsection (1) of this section or ORS 285B.656 (9) to exempt qualified hotel, motel and destination resort property located within the zone may such property of applicable precertified business firms be eligible for an exemption under ORS 285B.722 within that zone.

(3) For purposes of subsection (1)(a) of this section, notifications to the Department of Revenue on or before December 1, 1989, that exercise a sponsor's option of exempting hotel, motel or destination resort property are void on and after September 15, 1997. [Formerly 285.610]

Note: See note under 285B.650.

285B.719 Precertification for exemption. (1) Any eligible business firm proposing to apply for the tax exemption provided under ORS 285B.698 shall, before the commencement of construction, modification or installation of qualified property in an enterprise zone, and before the hiring of eligible employees, apply for precertification with the sponsor of the zone and with the county assessor of the county or counties in which the zone is located. The application shall be made on a form prescribed by the Department of Revenue and the Economic and Community

Development Department.

(2) The application shall contain the following information:

(a) A description of the nature of the firm's business operations in the enterprise zone;

(b) A description and estimated cost or value of the qualified property to be constructed, modified or installed in the enterprise zone;

(c) An estimate of the number of employees that will be hired by the firm;

(d) A commitment to meet all requirements of ORS 285B.704;

(e) A commitment to satisfy all additional conditions for precertification that are imposed by the enterprise zone sponsor under ORS 285B.671 (4); and

(f) Any other information considered necessary by the Department of Revenue and the Economic and Community Development Department.

(3) If the sponsor and county assessor determine that the business firm is eligible under ORS 285B.707 and that the firm has committed to meet the requirements of ORS 285B.704, the sponsor and county assessor shall precertify the business firm by approving the application. The approval of both the sponsor and the county assessor shall be prima facie evidence that the eligible business firm will be qualified for the property tax exemption under ORS 285B.698. Neither the sponsor nor the county assessor shall be liable in any way if the Department of Revenue later determines that a precertified business firm is not qualified for a property tax exemption or if either the county assessor or the Department of Revenue determines that the precertified business firm has not satisfied the requirements of ORS 285B.704. In approving the application, the sponsor and county assessor shall provide proof of approval as directed by the Economic and Community Development Department.

(4) If the sponsor or county assessor fails or refuses to precertify the business firm, the business firm may appeal to the Oregon Tax Court under ORS 305.404 to 305.560. The business firm shall provide copies of the firm's appeal to the sponsor, county assessor, the Department of Revenue and the Economic and Community Development Department.

(5) Notwithstanding the fact that an enterprise zone has terminated under ORS 285B.686 or that a zone boundary has been changed, an eligible business firm that has obtained precertification under this section shall be entitled to a property tax exemption under ORS 285B.698, if, as determined by the Economic and Community Development Department:

(a) The firm's application for precertification has not been withdrawn by the firm or has not expired;

(b) The firm completes construction, modification or installation of the qualified property within a reasonable time and without interruption of construction or installation activity; and

(c) The firm satisfies all other requirements of ORS 285B.704 and the precertification.

(6) If an enterprise zone is terminated under ORS 285B.686, the exemption under ORS 285B.698 shall be granted only if the sponsor and county assessor approve the application for precertification, such that the sponsor, county assessor or both formally granted such approval on or before the effective date of the termination of the zone, and the business firm satisfies subsection (5) of this section. If the sponsor or county assessor refuses or fails to precertify the firm under this subsection, the firm may appeal under subsection (4) of this section and may be granted the exemption.

(7) Precertification under this section shall not ensure that property constructed, modified or installed by the precertified business firm will receive property tax exemption under ORS 285B.698.

(8) Notwithstanding any other provision of this section, if a business firm satisfies the requirements of ORS 285B.704 and has constructed, modified or installed qualified property eligible for exemption under ORS 285B.698, the precertification requirement of subsection (1) of this section or ORS 285B.722 may be waived as specifically provided by rule or for good cause by the Department of Revenue. [Formerly 285.613]

Note: See note under 285B.650.

285B.722 Application for exemption upon completion of construction or modification; effect of exemption. (1) After January 1 and no later than April 1 of the assessment year immediately following completion of construction or modification or the installation of qualified property, a precertified business firm may apply for the exemption allowed under ORS 285B.698. The application shall be made on a form prescribed by the Department of Revenue and shall be filed with the county assessor. If the property for which exemption is sought is leased by the business firm, the application shall be made by both the owner and the lessee of the property.

(2) An application filed under this section shall contain:

(a) A statement that:

(A) The business firm satisfies the requirements of ORS 285B.704 as a qualified business firm; and

(B) The business firm has been precertified by the enterprise zone sponsor and the county assessor.

(b) Any other information required by the Department of Revenue.

(3) The business firm shall be prepared to verify the dates on which its application for precertification was submitted and approved. The statement made pursuant to subsection (2)(a) of this section shall be prima facie evidence that the firm is a qualified business firm.

(4) If the assessor determines the property for which exemption is sought satisfies the requirements of ORS 285B.698, the assessor shall grant the exemption. Thereafter, for each assessment year that the property is exempt from taxation, the assessor shall:

(a) Enter on the assessment roll, as a notation, the assessed value of the property as if it were not exempt under ORS 285B.698.

(b) Enter on the assessment and the tax roll, as a notation, the amount of additional taxes that would be due if the property were not exempt.

(c) Indicate on the assessment and tax roll that the property is exempt and is subject to potential additional taxes as provided in ORS 285B.728, by adding the notation "enterprise zone exemption (potential additional tax)."

(5) If the assessor denies an exemption applied for under this section, the business firm may appeal the denial to the Oregon Tax Court under ORS 305.404 to 305.560.

(6) The assessor shall provide copies of each exemption application filed under this section to the enterprise zone sponsor and as directed by the Department of Revenue.

(7) If an application required by subsection (1) of this section relates to principal or secondary industrial property as defined by ORS 306.126 and is filed with the Department of Revenue within the time required by subsection (1) of this section, the application shall be deemed timely filed with the assessor. [Formerly 285.615]

Note: See note under 285B.650.

285B.723 First-source hiring agreement necessary for exemption; waiver; rules. (1) Except as provided in subsection (3) of this section, the county assessor may not approve an application or grant the exemption under ORS 285B.722 (4) unless a first-source hiring agreement under ORS 285B.710 (1) is in effect and a copy of the agreement is included with the application.

(2) The exemption that a qualified business firm is receiving or has received may not be disqualified retroactively or terminated for failure to meet the requirements of subsection (1) of this section or ORS 285B.710 (1).

(3) In accordance with rules adopted by the Economic and Community Development Department, the Director of the Economic and Community Development Department may waive the requirements of subsection (1) of this section or ORS 285B.710 (1) for a precertified business firm. The rules adopted by the department shall provide for a waiver under this subsection when the director finds that:

(a) The business firm is unable to employ persons referred under the agreement; or

(b) The waiver will further the goals and purposes of applicable state policies. [1999 c.1104 s.2]

Note: See note under 285B.650.

285B.725 Late application for exemption; filing fee. (1) Notwithstanding ORS 285B.722 (1), an application for exemption under ORS 285B.722 may be filed under this section at any time on or before June 1 of the assessment year for which exemption is first sought. However, any application filed after the time for filing specified in ORS 285B.722 (1) must be accompanied by a late filing fee in the greater of the amounts of $200 or one-tenth of one percent of the real market value of the property, determined as of January 1 of the assessment year to which the application pertains, by the assessor for this purpose. If the application is not accompanied by the late filing fee or if the late filing fee is not otherwise paid, no exemption shall be allowed based upon an application filed pursuant to this section.

(2) An application may be filed under this section whether or not there are grounds for hardship as required for late filing under ORS 307.475.

(3) The value of the property used to determine the late filing fee under this section is appealable in the same manner as other acts of the county assessor.

(4) Any filing fee collected under this section shall be deposited to the county general fund. [Formerly 285.616; 1999 c.1104 s.7]

Note: See note under 285B.650.

285B.728 Notice to assessor and sponsor if property or business becomes unqualified for exemption. (1) The county assessor of any county in which an enterprise zone is situated and the sponsor shall be notified in writing by the qualified business firm or by the owner of the qualified property leased by the qualified business firm not later than July 1 following the assessment year for which the exemption is claimed but in which one of the following events occurs:

(a) Property granted exemption from taxation under ORS 285B.722 is sold, exchanged, transported or otherwise disposed of for use outside the enterprise zone or for use by an ineligible business firm;

(b) A qualified business firm closes or substantially curtails the operation of the trade or business in which property granted exemption from taxation under ORS 285B.722 is used, except as allowed by the zone sponsor under ORS 285B.704 (2) or (3);

(c) A qualified business firm fails to meet any of the requirements of ORS 285B.704 (2)(b) or (3)(b);

(d) A qualified business firm fails to meet any of the requirements of ORS 285B.710 (2), (3) or (6);

(e) A qualified business firm fails to meet any of the requirements of ORS 285B.710 (4) or (5); or

(f) A qualified business firm or the applicable activity or operation of the firm fails to meet any of the requirements of ORS 285B.707 or 285B.713 (2)(f) or (g) after it has received a property tax exemption for its qualified property.

(2)(a) When an assessor receives written notice under subsection (1) of this section, the assessor shall disqualify the property for the assessment year following the disqualifying event and 100 percent of the additional taxes calculated under ORS 285B.722 shall be assessed against the property for each year for which the property had been granted exemption.

(b) Notwithstanding paragraph (a) of this subsection, if a qualified business firm fails to meet any of the requirements in ORS 285B.710 (3), (4) or (6) during the exemption, but meets the requirements of ORS 285B.698 during the first three years of the exemption, the qualified business firm is entitled to receive the property tax exemption allowed under ORS 285B.698 (3).

(c) The additional taxes assessed under this subsection shall be reduced by the amount, if any, paid by the qualified business firm to the sponsor under subsection (6) of this section for the same property.

(3) For the purposes of ORS 285B.704 and this section, operation of a business firm shall be considered to be substantially curtailed when:

(a) The number of employees within the enterprise zone is reduced at the end of an assessment year by more than 85 percent from the highest number of such employees at the end of any assessment year during which the business firm received a property tax exemption under ORS 285B.698 or 285B.710;

(b) The number of employees within the enterprise zone at the end of an assessment year has been reduced for a period longer than one year by more than 50 percent from the highest number of such employees at the end of any assessment year during which the firm was receiving a property tax exemption under ORS 285B.698 or 285B.710; or

(c) The average annual number of employees within the enterprise zone is reduced at the end of the first assessment year of exemption and any subsequent qualifying years below 110 percent of the average annual number of employees at facilities of the firm located within the enterprise zone on the date of application for precertification.

(4) If the qualified business firm or owner fails to give the notice on time or at all as required by subsection (1) of this section, upon discovering the property no longer qualifies for the exemption due to a circumstance described in subsections (1) and (3) of this section, the assessor shall:

(a) Compute the amount of taxes described in subsection (2) of this section as though notice had been given, and shall add to that amount an additional penalty equal to 20 percent of the total amount so computed; and

(b) Add the property to the assessment and tax roll without the exemption as if the notice had been given.

(5) The amount determined to be due under subsections (2) and (4) of this section:

(a) May be paid to the tax collector before completion of the next general property tax roll pursuant to ORS 311.370; and

(b) Shall be added to the tax extended against the property on the next general property tax roll to be collected and distributed in the same manner as the remainder of the property taxes.

(6)(a) Notwithstanding subsections (2) and (5) of this section, when an assessor and sponsor receive notice under subsection (1)(b), (c), (d) or (e) of this section and the qualified business firm has not closed its operations, the qualified business firm shall pay the sponsor an amount equal to the property taxes for the qualified property in the assessment year for which the exemption is claimed.

(b) Moneys collected under paragraph (a) of this subsection shall be used by the sponsor to benefit the residents of

the enterprise zone and for the development of jobs, skills and training for residents of the enterprise zone and the zone's immediate vicinity.

(c) This subsection applies only to the first notice under subsection (1)(b), (c), (d) or (e) of this section or for the second notice under subsection (1)(b), (c), (d) or (e) of this section in the case of the final year of an exemption lasting a total of five consecutive years under ORS 285B.710.

(d) If the sponsor does not receive the full amount to be paid by the qualified business firm under paragraph (a) of this subsection, the assessor shall disqualify the property under subsections (2) and (5) of this section.

(7) The assessor is at all times authorized to demand by registered or certified mail reports from owners or lessees concerning the use of the qualified property and the employment status of the qualified business firm for purposes of this section. If the owner or lessee fails after 60 days' notice in writing by certified mail to comply with such demand, the assessor may disqualify the exemption in accordance with subsection (2) of this section, giving written notice of the disqualification to the Department of Revenue and the owners or lessees of the qualified property.

(8) The assessor is under no obligation to verify compliance by qualified business firms with requirements imposed under ORS 285B.710 (2), (3)(b), (4), (5) or (6)(b).

(9) The sponsor of an enterprise zone may initiate procedures in order to verify compliance by qualified business firms with requirements imposed under ORS 285B.692 to 285B.728. The procedures may include written requests to the assessor by the local zone manager or an executive official of the sponsoring jurisdiction in which the qualified business firm is located that the assessor exercise authority under subsection (7) of this section for a particular qualified business firm.

(10) An assessor may not impose the property taxes and penalties specified in subsection (4) of this section for failure by a qualified business firm or an owner of qualified property leased by the qualified business firm to notify the assessor or the enterprise zone sponsor that the qualified business firm does not meet requirements under ORS 285B.710 (2), (3)(b), (4), (5) or (6)(b), without having received written communication from the zone sponsor that demonstrates that the qualified business firm does not meet such requirements.

(11) Additional taxes collected under this section shall be deemed to have been imposed in the year to which the additional taxes relate. [Formerly 285.617; 1999 c.1104 s.8]

Note: See note under 285B.650.

(Miscellaneous)

285B.731 Short title for ORS 285B.650 to 285B.728. ORS 285B.650 to 285B.728 shall be known and may be cited as the Oregon Enterprise Zone Act of 1989. [Formerly 285.620]

Note: See note under 285B.650.

ENTREPRENEURIAL DEVELOPMENT

285B.740 Policy. It is the intent of the Legislative Assembly that in the administration of ORS 285B.740 to 285B.758, the Economic and Community Development Department work closely with regional economic development organizations, community development corporations, small business development centers and organizations that promote and assist small businesses owned and operated by women and minorities, as defined by ORS 285B.050 (9). The Economic and Community Development Department, to the maximum extent feasible and consistent with prudent financial controls, may delegate the administration and operation of the loan program created by ORS 285B.740 to 285B.758 to local and community-based entities. To carry out the policy described in this section:

(1) The Economic and Community Development Department may contract with any nonprofit corporation or agency with experience and expertise in business finance to administer all or any part of the loan program created by ORS 285B.740 to 285B.758.

(2) When entering into an agreement for the administration of the loan program by any nonprofit corporation or agency, the Economic and Community Development Department may agree to waive any claims it may have against such corporation or agency for losses arising out of the normal course of business, so long as the corporation or agency does not act negligently or fraudulently in providing loans under ORS 285B.740 to 285B.758.

(3) When entering into an agreement to have a nonprofit corporation or agency administer the loan program created by ORS 285B.740 to 285B.758, the Economic and Community Development Department may pay loan

origination and loan servicing fees to the corporation or agency. The amount of such fees may be determined in the agreement between the department and the administering corporation or agency. [1991 c.688 s.12]

285B.743 Application for entrepreneurial development loan; eligibility. (1) Any individual or business firm may file with the Economic and Community Development Department an application to borrow money from the Oregon Entrepreneurial Development Loan Fund as provided in ORS 285B.740 to 285B.758. The application shall be filed in such a manner and contain or be accompanied by such information as the department may require.

(2) Upon receipt of an application under this section, the Economic and Community Development Department shall determine whether the applicant is eligible to receive a loan under ORS 285B.139, 285B.740 to 285B.758 and 285B.765. If the department determines that an applicant is not eligible to receive a loan, the department shall:

(a) Reject the application with a written statement of the reason for that rejection; or

(b) Require the applicant to submit additional information concerning the application as may be necessary. [1991 c.688 s.7]

285B.746 Conditions required for loan approval. (1) The Economic and Community Development Department may approve a loan requested in an application filed under ORS 285B.743 if, after investigation, it finds that:

(a) The applicant is enrolled in a small business management program with a small business development center;

(b) The applicant has prepared a business plan for the business, which has been reviewed by a small business development center or other entity certified by the Economic and Community Development Department to review business plans;

(c) The applicant has developed an expenditure plan for the use of the moneys received as a loan for the project under ORS 285B.740 to 285B.758; and

(d) The applicant is not effectively owned or controlled by another business entity or other person that, either by itself or when combined with the applicant, is not eligible for a loan under ORS 285B.740 to 285B.758.

(2) In addition to the requirements for loan approval described in subsection (1) of this section, in order to obtain a loan under ORS 285B.740 to 285B.758, an applicant must also satisfy two of the following conditions:

(a) The business or proposed business, at the time of application, must not have been operating for more than 24 months.

(b) The business must have annual revenues of less than $100,000 in the 12-month period immediately preceding the date of application.

(c) The business or proposed business is owned in whole or in part by a person certified as being severely disabled by the Vocational Rehabilitation Division of the Department of Human Services or the Commission for the Blind. [1991 c.688 s.8; 1997 c.147 s.5]

285B.749 Additional conditions for loan approval; maximum term and amount of loan; deferral of repayment. (1) The Economic and Community Development Department may approve an entrepreneurial development loan under ORS 285B.740 to 285B.758 if, after investigation, it finds that:

(a) The loan has a reasonable prospect of repayment;

(b) The applicant provides funds for the project in the form of cash, property or business equity in an amount equal to 20 percent of the amount of the loan; and

(c) The applicant can provide such evidence of assurance for repayment as the department considers appropriate to the circumstances of the particular applicant. However, loans need not be secured with real property.

(2) The Economic and Community Development Department may make an entrepreneurial development loan to any single applicant in an amount not exceeding $25,000.

(3) Entrepreneurial development loans shall be made for a period not exceeding five years at a rate of interest that does not exceed 18 percent per annum.

(4) The Economic and Community Development Department may defer repayment of a loan by an applicant for a period not exceeding six months. However, interest shall continue to accrue on the unpaid principal amount of the loan during such period of deferred repayment. [1991 c.688 s.9; 1997 c.147 s.6]

285B.752 Additional loans; maximum aggregate amount. An applicant who receives an entrepreneurial development loan under ORS 285B.740 to 285B.758 may apply for another such loan. Notwithstanding the limit set forth in ORS 285B.749 (2), the maximum aggregate amount that may be loaned to a single applicant under ORS 285B.139, 285B.740 to 285B.758 and 285B.765 is $40,000. [1991 c.688 s.10; 1997 c.147 s.7]

285B.755 Oregon Entrepreneurial Development Loan Fund Advisory Committee. (1) The Economic and Community Development Department shall appoint an Oregon Entrepreneurial Development Loan Fund Advisory Committee of not less than five members to advise the department on the operation of the loan program created by ORS 285B.740 to 285B.758. The individuals appointed to the advisory committee shall be representatives of the private sector financial community, public sector business finance groups, small business support organizations and owners and operators of small businesses. The advisory committee shall include at least one owner or operator of a small business who is a woman or a member of a minority group. The advisory committee shall also include at least one person who is a representative of disabled Oregonians.

(2) The Oregon Entrepreneurial Development Loan Fund Advisory Committee shall review all loan forms, contracts and other administrative materials to assure that the loan program created by ORS 285B.740 to 285B.758 operates with administrative simplicity and efficiency to the greatest extent possible. [1991 c.688 s.11]

285B.758 Oregon Entrepreneurial Development Loan Fund. (1) There is established in the State Treasury, separate and distinct from the General Fund, the Oregon Entrepreneurial Development Loan Fund. All moneys in the fund are continuously appropriated to the Economic and Community Development Department for the following purposes:

(a) Administrative costs of the department incurred in processing loan applications, investigating the eligibility of loan applicants and servicing outstanding loans;

(b) Paying for loan origination and loan servicing by contractors under ORS 285B.740 to 285B.758; and

(c) Payment of loans to applicants under ORS 285B.740 to 285B.758.

(2) The Oregon Entrepreneurial Development Loan Fund shall consist of:

(a) Moneys appropriated to the fund by the Legislative Assembly;

(b) Interest earned on moneys in the fund; and

(c) Moneys received as repayment of principal and interest on loans made from the fund under ORS 285B.740 to 285B.758. [1991 c.688 s.13]

MISCELLANEOUS

285B.765 Oregon Dislocated Worker Fund. (1) There is established in the State Treasury, separate and distinct from the General Fund, the Oregon Dislocated Worker Fund. All moneys in the fund are continuously appropriated to the Economic and Community Development Department for the purpose of carrying out ORS 285B.139, 285B.740 to 285B.758 and 285B.765.

(2) The Economic and Community Development Department, in consultation with the Employment Department and the Job Training Partnership Act section of the Department of Community Colleges and Workforce Development, shall develop rules to allocate moneys from the Oregon Dislocated Worker Fund to provide assistance to dislocated timber workers, including but not limited to, training services, emergency medical assistance, child care, tuition or any activities authorized by the Economic and Community Development Department.

(3) The intent of this section is to provide assistance to dislocated timber workers when federal funding is reduced, is inadequate or is otherwise not available.

(4) For the purposes of this section, “dislocated timber worker” includes persons who the Economic and Community Development Department determines are likely to become dislocated based on employer notification of layoffs or other reliable information available to the department. [1991 c.688 s.6; 1997 c.61 s.12]

Oregon Eyes Lottery Funds to Build Pipeline

By NGI Staff Reports on March 08, 1999 at 12:00 a.m.

In an effort to attract large businesses to their districts, twoOregon state legislators introduced a bill recently that wouldprovide $20 million in lottery funds to help build a 64-milepipeline. No engineering study for the pipeline has been conductedso far. The bill's main supporters, state Sen. Veral Tarno(R-Coquille) and Rep. Ken Messerle (R-Coos County), said some ofthe funds also could be used to build a high-voltage power line.

As the area's timber industry has faltered, the Coos Countyunemployment rate has grown to 10%, nearly double the state'saverage. A Coos County official said 1,700 jobs have been lost and14 companies have passed on building plants in the area because ofthe lack of natural gas access. Overall, 61,000 people in the CoosBay area are without natural gas service.

Nucor Corp., a Charlotte, NC-based steel manufacturer, hasexpressed interest in building a $280 million steel mill in thearea, but only if the power line is built. The Bonneville PowerAdministration (BPA) is conducting an environmental impact study onthe proposed $80 million power line, but Nucor, the BPA andinterested utility companies have not been able to decide whoshould pay for it.

John Norris

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September 26, 2025

NWN OPUC Advice No. 25-23

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attention: Filing Center
201 High Street SE, Suite 100
Salem, Oregon 97301-3398

Re: Schedule 160 – Cancellation of Charges for Coos County Customers and Proposal for Coos County Pipeline

Northwest Natural Gas Company, dba NW Natural (NW Natural or Company), files herewith the following revision to its Tariff P.U.C. Or. 25, stated to become effective December 31, 2025.

First Revision of Sheet 160-1	Schedule 160	Revision of Charges for Coos County Customers

NW Natural proposes to cancel Schedule 160 as part of its plan to terminate its existing Transportation Services Agreement (TSA) with Coos County, as described in detail below. Under the TSA, NW Natural purchases transportation service on the county-owned Coos County Pipeline (Pipeline) in order to serve the Company's customers in Coos County. NW Natural also currently operates and maintains the Pipeline for Coos County under the terms of the TSA. Cancelling Schedule 160 and terminating the TSA will facilitate NW Natural's purchase of the Pipeline. By purchasing the Pipeline, NW Natural will be able to make investments in much-needed landslide prevention work that will ensure safe and reliable gas service for NW Natural's customers that depend on the Pipeline.

Purpose

The purpose of this filing is to cancel Schedule 160 as part of NW Natural's overall plan to continue to provide safe and reliable gas service to Coos County. Importantly, Coos County meets the definition of an environmental justice community per ORS 756.010(5). ORS 756.010(5) defines environmental justice communities, in part, as "coastal communities," "rural communities," "communities with limited infrastructure," and "communities experiencing lower incomes." Therefore, Coos County, located in a rural area along the Oregon Coast with limited energy infrastructure that is dependent on the county-owned Pipeline and whose household median income is less than the state and national median,[1] is an environmental justice community.

[1] As discussed below, the median household income for a Coos County household is $60,313, whereas the Oregon median household income is $80,426 and the national median income is $78,538.

To ensure safe and reliable gas service to this environmental justice community, approximately $10 million of landslide prevention work (prior to applying construction overhead) must be completed on the county-owned Pipeline prior to the 2026-2027 winter heating season. Unfortunately, Coos County is not in a financial position to complete this work itself. In addition, the residents and businesses of Coos County that are ultimately served by the Pipeline would struggle to solely bear the cost of this landslide prevention work and continue to shoulder the costs of the natural gas distribution system in Coos County—a portion of which were directly assigned to these communities through Schedule 160.

NW Natural has coordinated closely with Coos County to find a solution that is in the best interests of the County, its residents and businesses, and the Company's customers. Therefore, NW Natural requests the Public Utility Commission of Oregon's (Commission) approval to cancel Schedule 160 by December 31, 2025, with the understanding that NW Natural will seek to recover Pipeline-related costs in a future cost recovery proceeding. To facilitate the recovery of these Pipeline-related costs, NW Natural will acquire the Pipeline from Coos County for $1.00 (one dollar) upon Commission approval of this filing and use deferred accounting to track the operations and maintenance (O&M) costs related to remediation and maintenance work, as explained below. The Company's proposed cancellation of Schedule 160 is attached.

Background

In 1999, the Oregon Legislative Assembly provided $24 million in state funding ($20 million in lottery funds and $4 million in economic development funds) for Coos County to construct a 60-mile Pipeline that would route natural gas from the Williams pipeline near Roseburg to the south coast to increase economic development in the area. Coos County voters authorized general obligation funds of $27 million to cover the balance of the construction costs. The Pipeline entered service in January 2005.

On July 30, 2001, NW Natural and Coos County entered into the TSA under which NW Natural agreed to construct distribution facilities that would connect customers to natural gas when the Pipeline was completed. NW Natural provides gas service to its Coos County customers by transporting gas through the Williams pipeline, purchasing gas transportation services from Coos County on the Pipeline through the TSA, and then delivering gas on NW Natural's distribution system to customers. The Company currently collects $0.01271 per therm of monthly nominations from Coos County transportation customers, of which there are three as of August 2025, for these transportation services per the TSA.[2]

[2] Per the TSA, the "the initial Transportation Rate shall be 10 cents per MMBtu" and "at the end of the tenth year of the initial term … the 10-cent fee will be adjusted in proportion to changes in CPI." Therefore, the Company charged $0.01000 per therm for transportation service for the initial term (equal to 10 cents per MMBtu), and for the second ten-year term adjusted this amount to $0.01271 per the Consumer Price Index for All Urban Consumers (seasonally adjusted) as specified in the TSA.

The Commission adopted the Second Stipulation Relating to the Coos County Distribution System (Stipulation) in docket UG 152 (Order No. 03-236) (Order) in April 2003 that addressed how NW Natural's distribution system investments would be recovered from customers, including a two-cent per therm surcharge on Coos County sales customer bills (referred to as the "Coos County Charge" and collected under the Company's tariff Schedule 160).[3] In January 2005 the distribution system, which NW Natural invested over $11.5 million to construct in Coos Bay, entered service coincident with the Pipeline. There were several terms included in the Stipulation and Order, and those of which that are relevant to this proposal are summarized below:

(1) For ratemaking purposes, NW Natural's investment in the Coos County gas distribution system was capped at $12 million.

(2) The $12 million investment was included in the Oregon rate base. However, the Stipulation provided that Coos County sales customers will repay $1.6 million of the initial gas distribution system investment through the two-cent per therm Coos County Charge. Collection of the Coos County Charge is applied first to pay the O&M expenses for transportation services on the Pipeline as determined by the TSA, and then to repay the $1.6 million Coos County customer share of the initial investment in the gas distribution system.

(3) The rate charged to industrial transportation customers per the TSA will also be applied to pay the O&M expenses for transportation services on the Pipeline. This is meant to increase the amount of the two-cent Coos County Charge available to reduce the $1.6 million Coos County customer share.

(4) After collection of the Coos County Charge, any balance for O&M expenses for transportation services on the Pipeline will be recoverable, statewide, from Oregon sales service customers as part of the Company's annual purchased gas adjustment (PGA).

(5) If the $1.6 million Coos County customer share has not been paid down by the end of the Initial Term ending December 31, 2025, a new schedule to amortize the balance, approved by the Commission, will be established.[4]

Lastly, in January 2005, NW Natural exercised its option under the TSA to assume responsibility for operating and maintaining the transmission pipeline as Coos County's contractor under a separate service agreement. Under the agreement, NW Natural's obligations include supervisory, administrative, technical, and other services as may be required to be performed relative to operating and maintaining the Pipeline. All costs

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[3] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Application for a General Rate Revision,* Docket No. UG 152, Second Stipulation Relating to the Coos County Distribution System (April 9, 2003).
[4] Note that Schedule 160 currently reflects an incorrect TSA ending date of December 31, 2024. The TSA provides that the initial term of the TSA will end on December 31 of the twentieth year after the year in which the Pipeline becomes operational. The Pipeline construction was completed and gas flowing on NW Natural's distribution system on January 19, 2005. As a result, the initial term expires December 31, 2025.

incurred by NW Natural associated with these services are subject to reimbursement from the County. Extraordinary and emergency services work, as defined in the service agreement, require the Company to notify the County of a workplan and budget and is subject to the County's approval of such work.

Current Status of the Coos County Pipeline

As of August 2025, the Company has 2,307 Coos County customers served by the pipeline, of which 1,793 are residential customers, 502 are commercial customers, and nine are industrial sales service customers. Additionally, as stated above, there are three transportation customers. Coos County relies on the Pipeline as the single source of natural gas delivery to the area. The forest products industry is the largest consumer of natural gas in the region, accounting for about 80.5% of industrial throughput and about 39.5% of all Coos County pipeline throughput for the twelve months ending March 2025.

The Coos County Pipeline has significant safety issues due to landslide risks. In 2021, NW Natural commissioned a study to identify landslide areas near the Pipeline. In that study, nine landslide areas were identified as moderate/low risk where federal code required monitoring practices to sufficiently address the safety risk.[5] Three areas were identified as having a higher risk of a major landslide. The Company is currently monitoring each of these identified landslide risk areas, with more frequent monitoring of the higher risk areas. It is important to note that one of the higher risk areas was identified initially as moderate/low risk - so even with a highly reputable point-in-time study, it is hard to accurately predict landslide safety risks. Severe storms, for instance, can heighten the risk at certain areas or expose new areas to landslide risk.

In March 2025, heavy rains in Southwest Oregon caused widespread damage due to flooding, landslides, mudslides, sinkholes, and rockfalls resulting in a Level 3 regional emergency response activation from the Oregon Department of Emergency Management.[6] In Coos County, heavier than normal rainfall caused the Coos and Coquille River watersheds to flood, resulted in damage at approximately 90 sites on county roads, and required the Coos County Sheriff's Office to deploy search and rescue operations to protect life and safety. Due to the severity of the damages from the storm, the Federal Emergency Management Agency (FEMA) declared a presidential disaster on July 22, 2025, which made available federal disaster assistance.[7] Landslides related to this storm, as discussed in greater detail below, have resulted in higher risk of failure at multiples points along the Pipeline and therefore have made the Company's request in this filing more urgent.

Coos County does not have the ability to back a bond measure to mitigate the landslide risk for the Pipeline. Coos County has been working to find grants and other types of programs to help offset these expenses, including the FEMA Building Resilient Infrastructure in

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[5] 49 C.F.R. 192.
[6] *See*: https://www.opb.org/article/2025/03/18/oregon-department-emergency-management-flooding-southwest-oregon-weather-rain/.
[7] Oregon Department of Emergency Management 2025 March Flooding Spotlight. *See*: https://storymaps.arcgis.com/stories/5b3ecd47075844fe8a1d95f28a8e643b.

Communities (BRIC) grant request, and has secured $1.45 million in American Rescue Plan Act funds to offset the cost of this work. In expressing their support for the Coos County application for a FEMA BRIC grant to fund hazard mitigation work on the pipeline, Oregon Senators Jeff Merkley and Ron Wyden noted that "the existing pipeline is currently the only source of natural gas in the county" and "If this pipeline were to fail, as is expected in its current state, it could have an enormous impact on the local economy with businesses and hundreds of households reliant on gas from the pipeline."[8]

Necessary Landslide Risk Prevention Work

There are three major landslide areas along the Pipeline that need to be addressed prior to the 2026-2027 winter heating season. The total cost of the work needed is expected to be approximately $10 million (prior to applying construction overhead costs). The three most critical locations are:

- **Coquille River**
  - Pipe relocation is necessary; a temporary above ground bypass has been installed due to the risk of a riverbank washout.
  - As stated above, Coos County will contribute $1.45 million in American Rescue Plan Act funds for this work.

- **Mile 98**
  - This is an active landslide area with temporary remediation steps in place.
  - The Mile 98 slide area has been identified as the highest risk location on the Pipeline.
  - The Company has requested and has been given approval from Coos County to hire a surveying firm to assess this slide area and present a long-term remediation design solution to the County.
  - There are currently no plans to relocate the Pipeline from this area.

- **Lookingglass**
  - This area became a high risk for landslides in March 2025. It was previously identified as a low-risk area. The March 2025 storm, described in greater detail above, caused a large landslide in this area of the Pipeline. Company crews examined the site and determined that although the landslide decreased the amount of soil cover over the Pipeline, the soil at the site is currently stable. The lack of soil cover and the presence of exposed soil, however, caused the Company to elevate its designation of this area from low risk to high risk.
  - Since the Pipeline is currently situated at and below the landslide area, restoration work is necessary.

[8] Letter in support of Coos County application for FEMA Building Resilient Infrastructure in Communities (BRIC) grant, from Oregon United States Senators Jeffrey A, Merkley and Ron Wyden to FEMA Administrator Deanne Criswell, dated January 21, 2025.

There are six additional landslide areas in the moderate/low risk categories that are also being monitored and their risk for landslides may change over time.

Proposed Ratemaking and Pipeline Purchase

In this filing, NW Natural is seeking to cancel Schedule 160 and terminate the TSA as part of its plan to maintain safe and reliable service to its Coos County customers and in response to the current condition of the Pipeline as discussed below. This plan also includes NW Natural acquiring the Pipeline from Coos County for $1.00 (one dollar). NW Natural already has an agreement in principle with Coos County to acquire the Pipeline. The proposed purchase of the Pipeline and related ratemaking treatment will allow NW Natural to begin work on the three critical landslide risk areas identified above and efficiently plan for future work.

NW Natural plans to separately file a deferral application that will allow it to track the operations and maintenance (O&M) costs related to remediation and maintenance work on the Pipeline. NW Natural would seek to recover these costs in a future ratemaking proceeding. At the time of the next general rate case, the ongoing O&M costs of the Pipeline would be placed in base rates.

By cancelling Schedule 160, terminating the TSA, and assuming ownership of the Pipeline, NW Natural anticipates that it will no longer assess Coos County customers an additional charge for gas service based on their geographic location (i.e., the Coos County Charge). This type of rate treatment will put NW Natural's Coos County customers in the same position as all of the Company's other Oregon customers whose rates are not set based on location. It is also important to note that through base rates, NW Natural's Coos County customers have been paying for projects outside of Coos County for the last twenty years. Moreover, the Pipeline will remain an important component of Oregon's energy infrastructure for the foreseeable future, supporting local industry and heating residents' homes.

NW Natural's proposed rate treatment is also equitable. As stated above, Coos County meets the definition of an environmental justice community, which includes coastal communities, rural communities, communities with limited infrastructure, and communities experiencing lower incomes. The median income for a Coos County household—$60,313—is considerably below both the Oregon and United States median of $80,426 and $78,538 respectively. The percentage of Coos County residents living in poverty also exceeds both the state and national averages.[9]

Given these circumstances, it is equitable to charge Coos County customers the same amount as any other NW Natural customer in Oregon. NW Natural understands that ORS 757.230(1) permits the Commission to consider "environmental justice factors that affect affordability," which presumably includes considering affordability for environmental justice communities. While NW Natural is not seeking special rate consideration for Coos County

[9] US Census Bureau, QuickFacts. *See*: https://www.census.gov/quickfacts/fact/table/OR,cooscountyoregon,coosbaycityoregon/PST045223.

customers due to such factors, it does believe that it is inequitable to continue to charge these customers more for natural gas service compared to every other community in its Oregon service territory. Instead, NW Natural is seeking to ensure the same rate treatment for Coos County customers as for any other Oregon customer.

As part of its proposal to terminate the TSA and purchase the Pipeline, the Company plans to work with existing Coos County transportation customers to cancel capacity releases they currently need to move their gas supplies across the Pipeline to the Company's distribution system. Avista Corporation (Avista), separately, has a TSA with Coos County for a small amount of deliverability on the Pipeline. The Company plans to work with Avista on arrangements necessary for its service on the Pipeline.

Customer Impacts of NW Natural's Proposal

Without the equal and equitable rate treatment proposed in this filing, Coos County customers will experience large rate increases. Although NW Natural is not requesting cost recovery of the Pipeline landslide prevention work in this filing, the Company believes it is nonetheless important to show the impact of allocating these costs to only Coos County customers. Table 1 below illustrates this expected rate impact, with Scenario 1 showing the impact of allocating the cost of the necessary $10 million for landslide risk prevention work described above to only Coos County customers. Scenario 2 shows the impact assuming the costs were allocated to all of NW Natural's Oregon customers (NW Natural's proposal).

Table 1
Estimated Rate Impacts at Existing Rates Associated with Necessary Landslide Risk Prevention Work: Spread Based on Scenario 1 - Coos County Customers Only, Compared to Scenario 2 - All Oregon Customers (NW Natural's Proposal)

Estimated Impacts	Scenario 1 Impacts: Coos County Customers	Scenario 2 Impacts: All Oregon Customers
Pipeline ownership	NW Natural	NW Natural
Pipeline landslide risk prevention work [1]	$10 Million	$10 Million
On-going O&M (Annual)	$400k	$400k
Rate spread methodology	Equal percent of margin	Equal percent of margin
Recovery of initial distribution investment	No	No
Estimated Residential Bill Impacts [2]		
Average Residential bill increase (%)	37.2%	0.2%
Average Residential bill increase ($)	$25.27	$0.14
Estimated Bill Commercial and Industrial Bill Impacts, Selected Schedules [2]		
General Commercial (C03)	34.5% ($106.54)	0.2% ($0.54)
Large Commercial Sales Firm (32CSF)	22.0% ($962.58)	0.1% ($6.16)
Industrial Transportation Firm (32ITF)	55.6% ($4,495.17)	0.3% ($21.49)
Industrial Transportation Interruptible (32ITI)	55.9% ($1,619.29)	0.3% ($31.21)

1: Pipeline landslide risk prevention cost estimate is prior to applying construction overhead costs.
2: Bill impacts based on average usage by customers in each group (Coos County, or all of Oregon).

Table 1 shows that Coos County residential customers would face a 37.2% rate increase if the Pipeline landslide prevention costs were solely allocated to them, whereas Oregon residential customers would see their bills increase by only 0.2% if these costs were allocated to all customers. Given the importance of the Pipeline, how it supports local industry, and how it would further equity, NW Natural considers its proposal to allocate these costs on a statewide basis to be in the best interest of the entire state of Oregon.

Current Regulatory and Contractual Framework of the Coos County Pipeline

The alternative to the Pipeline purchase proposal described above is to follow the regulatory and contractual framework of the TSA. In that case, NW Natural would update the fee for pipeline transportation service, adjusted based on O&M costs, for the Second Term of the TSA expiring on December 31, 2045. Importantly, this updated fee which would apply to transportation customers, would not include landslide prevention work that is necessary for safe and reliable service. Instead, under this alternative, Coos County would retain ownership of the Pipeline and, as explained above, it cannot afford to perform this work on its own.

Secondly, the Company would revise the Schedule 160 Coos County Charge for sales customers, where it would collect the full unrecovered portion of the original $1.6 million investment in Coos County's distribution system that was directly assigned to Coos County. Due to the current two-cent per therm Schedule 160 Coos County Charge first being applied towards transportation service under the TSA, and lower than forecasted customer growth, the unrecovered portion of the initial distribution system investment remains approximately $1.6 million. To recover this amount, the Schedule 160 Coos County Charge for Coos County sales customers would have to increase from $0.02 per therm to approximately $0.10 per therm based on existing Coos County customer counts and load. This would result in an approximately 4.9% increase for the average Coos County residential customer, or $3.67 per bill, which is *in addition* to the necessary landslide prevention work on the Pipeline as shown in Table 1 above.

NW Natural recognizes the order approving its initial investment in the Coos County distribution system (Order No. 03-236) assumes that the existing regulatory framework would be maintained after the initial term of the TSA expires on December 31, 2025, including Coos County's ownership of the Pipeline and NW Natural continuing to assess Coos County customers a Schedule 160 Coos County Charge, as described above. However, maintaining this status quo would not address the landslide risks the Pipeline faces today and it poses significant safety risks to the area surrounding the Pipeline. In addition, any failures on the Pipeline would impact the reliability of service to Coos County customers. Unplanned service interruptions would be costly for NW Natural's industrial and commercial customers and could also put residential customers at risk. Finally, the cost of landslide risk mitigation and remediation work would be borne solely by Coos County, an environmental justice community.

Before making this filing, NW Natural had conversations with all parties originally involved in the UG 152 Coos County distribution system docket (Commission Staff, Oregon Citizens' Utility Board, and the Alliance of Western Energy Consumers). No party objected to NW Natural making a different proposal than what was envisioned more than twenty years ago in Order No. 03-236, although all parties retain their right to continue to evaluate the Company's proposal.

Conclusion

As described above, cost recovery for the proposal described in this filing will be requested in a future ratemaking filing. Thus, there is no rate increase due to terminating the TSA and assuming ownership of the Pipeline. Rather, terminating the TSA will result in a rate reduction as the Company will no longer collect $0.01271 per therm of monthly nominations for transportation services from Coos County transportation customers, of which there are three as of August 2025.

In compliance with OAR 860-022-0025, NW Natural states that the proposal to cancel Schedule 160 will also reduce the rates of Coos County sales service customers by the amount of the two-cent per therm Coos County Charge. The change impacts 2,304 Coos County sales service customers (of which 1,793 are residential customers, 502 are commercial customers, and nine are industrial customers) as of August 2025. Because Schedule 160 collections are first applied towards transportation service under the TSA, cancelling Schedule 160 has no impact on the Company's annual revenue.

NW Natural respectfully requests approval to cancel Schedule 160, terminate the TSA, and assume ownership of the Pipeline with the understanding that NW Natural will seek to recover Pipeline-related costs in its next general rate case.

In accordance with ORS 757.205, copies of this letter and the filing made herewith are available in the Company's main office in Portland, Oregon and on its website at www.nwnatural.com.

Please address questions and correspondence on this matter to me with a copy to the following:

eFiling
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Portland, Oregon 97204
Fax: (503) 220-2579
Telephone: (503) 610-7330
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Sincerely,

/s/ Zachary Kravitz

Zachary Kravitz
Vice President, Regulatory Affairs and Resource Planning
NW Natural
250 SW Taylor Street
Portland, Oregon 97204

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25

First Revision of Sheet 160-1
Cancels Original Sheet 160-1

SCHEDULE 160

--CANCELLED-- (C)

(D)

78th OREGON LEGISLATIVE ASSEMBLY--2015 Regular Session

Enrolled
Senate Bill 32

Printed pursuant to Senate Interim Rule 213.28 by order of the President of the Senate in conformance with presession filing rules, indicating neither advocacy nor opposition on the part of the President (at the request of Senate Interim Committee on Rural Communities and Economic Development)

CHAPTER .....

AN ACT

Relating to natural gas; and declaring an emergency.

Be It Enacted by the People of the State of Oregon:

SECTION 1. The Legislative Assembly finds and declares that having access to natural gas is in the public interest and that the extension of natural gas pipelines and other infrastructure necessary for providing natural gas to areas that do not have access to natural gas is necessary for the communities of this state to preserve local economies, enlarge tax bases and generate additional economic opportunities.

SECTION 2. (1) The Public Utility Commission shall form a work group for the purpose of conducting a study on methods by which a public utility that furnishes natural gas may expand the public utility's service to areas that do not have access to natural gas. As part of the study, the work group shall review the commission's authority to authorize, and the commission's policies on, the expansion of natural gas services. At a minimum, the work group shall study:

(a) The commission's policies regarding the extension of natural gas mains;

(b) Mechanisms for funding the expansion of natural gas services, including the use of tariffs, the imposition of charges and fees, the use of unclaimed refunds and the establishment of accounts dedicated to the expansion of natural gas services;

(c) The submission of recommendations by public utilities that furnish natural gas;

(d) Possible processes for including in a public utility's rates the cost of projects involving the extension of natural gas pipelines and other infrastructure necessary for providing natural gas;

(e) Possible selection criteria for projects involving the extension of natural gas pipelines and other infrastructure necessary for providing natural gas; and

(f) The potential rate cap for projects involving the extension of natural gas pipelines and other infrastructure necessary for providing natural gas.

(2) The commission shall include in the work group:

(a) Representatives of public utilities that furnish natural gas, other energy suppliers, local governments and elected officials;

(b) Stakeholders who have an interest in the outcome of the study;

(c) Individuals who have knowledge about the subject matter of the study;

(d) One member from the House of Representatives who represents an area that does not have access to natural gas; and

(e) One member from the Senate who represents an area that does not have access to natural gas.

(3) The commission shall compile a report, including any recommendations for legislation, of the work group's findings and conclusions. The commission shall submit the report in the manner provided in ORS 192.245 to an interim committee of the Legislative Assembly related to energy no later than September 15, 2016.

SECTION 3. Sections 1 and 2 of this 2015 Act are repealed on January 2, 2017.

SECTION 4. This 2015 Act being necessary for the immediate preservation of the public peace, health and safety, an emergency is declared to exist, and this 2015 Act takes effect on its passage.

Passed by Senate March 4, 2015

Repassed by Senate June 30, 2015

.....
Lori L. Brocker, Secretary of Senate

.....
Peter Courtney, President of Senate

Passed by House June 29, 2015

.....
Tina Kotek, Speaker of House

Received by Governor:

.....M.,....., 2015

Approved:

.....M.,....., 2015

.....
Kate Brown, Governor

Filed in Office of Secretary of State:

.....M.,....., 2015

.....
Jeanne P. Atkins, Secretary of State

NW Natural®

Rates & Regulatory Affairs
UG 527
NW Natural Alternative Rate Mechanism
Data Request Response

Request No.: UG 527 CUB DR 3

Please provide a list of all customers in Coos County on Schedule 32ISI.

Response:

NW Natural objects to this data request because it seeks information that is not relevant and not reasonably calculated to lead to admissible evidence. Without waiving this objection, the Company states as follows:

Please see Confidential UG 527 CUB DR 3 Attachment 1. The attachment is being provided under confidential protection because it identifies customer names.

This page of Exhibit 315 has been redacted pursuant to General Protective Order No. 23-132.

Oregon
Tina Kotek, Governor

Public Utility Commission
201 High St SE Suite 100
Salem, OR 97301-3398
Mailing Address: PO Box 1088
Salem, OR 97308-1088
503-373-7394

1/31/2023

Chair Decker and Commissioners Tawney and Thompson

Enclosed is Staff's Final Report to conclude the agency's Natural Gas Fact Finding investigation. The Final Report is the summation of a two-year assessment that the Public Utility Commission (PUC) held with regulated gas utilities and stakeholders. Staff explored the potential ratepayer and system impacts of limiting gas utility greenhouse gas (GHG) emissions and the regulatory tools needed achieve compliance with state GHG policies.

As you are aware, this report is just one element of an extensive and ongoing conversation on utilities' role in decarbonizing the Oregon economy. This conversation was well underway before the PUC undertook this investigation and it has shaped PUC decision-making and activities over the last two years. Through our work across various dockets, Staff envisions this conversation will continue to proceed, evolve, and grow in importance as utilities work towards compliance with state decarbonization goals. The Fact Finding process has been integral to surfacing key issues for consideration and debate and will inform the PUC's approach to utility regulation, as it already has in 2022.

In this Final Report, Staff sought to address and incorporate the valuable feedback provided by numerous parties to the Draft Report. Staff also sought to reflect the PUC's decarbonization planning work and activities that continued throughout 2022, including Northwest Natural's 2022 General Rate Case and Cascade Natural Gas' Update to its 2020 Integrated Resource Plan.

Decarbonization of the natural gas sector is still in its earliest stages. There is much to be learned from the initial steps taken by Oregon utilities and stakeholders as well as the actions being taken regionally, nationally, and globally. As recognized in the Final Report, an effective and successful decarbonization of Oregon's natural gas sector will require continued and thoughtful analysis, communication, and review by all parties so that lessons can be learned and plans can be adapted as quickly and efficiently as possible to reach decarbonization goals. To aid in this work, Staff is seeking to bolster its own knowledge development by bringing in outside expertise to address targeted questions raised by the Fact Finding process—including studying how the PUC can begin taking steps towards a holistic, system-wide approach to decarbonization planning and evaluating the accuracy, appropriateness, and adequacy of existing utility integrated resource planning.

Staff thanks all the participants to the Fact Finding process and hopes that readers find the Final Report as useful as Staff found the entire development process.

Sincerely,

JP Batmale
Energy Resources and Planning Division Administrator, Public Utility Commission

Natural Gas Fact Finding

Final Report

January 2023

Oregon Public Utility Commission

Natural Gas Fact Finding Final Report

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Table 1: List of Acronyms and Abbreviations

AC	Avoided Cost
AQCC	Colorado Air Quality Control Commission
AVA/Avista	Avista Corporation
AWEC	Alliance of Western Energy Consumers
BE	Better Energy LLC
BIPOC	Black Indigenous and People of Color
BUILD	California Energy Commission Building Initiative for Low-Emission Development Program
CAA	Community Action Agencies
CCI	Community Climate Investment
CCSU	Carbon Capture Sequestration and Utilization
CEC	California Energy Commission
CECP	Massachusetts Clean Energy and Climate Plan
CEE	Minnesota Center for Energy and Environment
Climate Reality	Climate Reality Project, Portland Chapter
CNG	Cascade Natural Gas Company
CO2e	Carbon Dioxide Equivalent
CPP	Climate Protection Program
CPUC	California Public Utility Commission
CS	Climate Solutions
CUB	Oregon Citizens' Utility Board
DEI	Diversity, Equity, and Inclusion
DEQ	Oregon Department of Environmental Quality
DPU	Massachusetts Department of Public Utilities
DSP	Distribution System Planning
EC	Electrify Coalition
EDF	Environmental Defense Fund
EE	Energy Efficiency
EITE	Emission Intensive Trade Exposed
EJ	Environmental Justice
EO	Executive Order
ETO	Energy Trust of Oregon
GHG	Greenhouse Gas
HB	House Bill
IEPR	California Integrated Energy Policy Report
IRP	Integrated Resource Plan
JC - CS et al.	Joint Comments - Climate Solutions et al. (29 Organizations)
JC - EC et al.	Joint Comments - Electrify Coalition et al. (41 Organizations)
JC - Mayoral	Joint Mayor City Official Letter
JC - MCAT	Joint Comments - Metro Climate Action Team et al. (3 Organizations)
JC - NWGA et al.	Joint Comments - NWGA et al. (17 Organizations)

LDC	Local Distribution Company
LEA	Line Extension Allowance
LI	Low Income
LMI	Low - Medium Income
LWVO	League of Women Voters of Oregon
MCAT	Metro Climate Action Team
MMBtu	1 Million British Thermal Units
MT	Metric Tons
Multnomah County	Multnomah County Office of Sustainability
NEEA	Northwest Energy Efficiency Alliance
NG	Natural Gas
NGFF	Natural Gas Fact Finding
NOPR	Notice of Proposed Rulemaking
NRDC	Natural Resources Defense Council
NWEC	Northwest Energy Coalition
NWGA	Northwest Gas Association
NWN	Northwest Natural
OAR	Oregon Administrative Rules
ODOE	Oregon Department of Energy
OPSR	Oregon Physicians for Social Responsibility
ORS	Oregon Revised Statutes
PBR	Performance Based Ratemaking/Regulation
PM	Public Meeting
PUC	Oregon Public Utility Commission
RAP	Regulatory Assistance Project
RFA	Rates, Finance, and Audit Division
RHN	Renewable Heat Now
RMI	Rocky Mountain Institute
RNG	Renewable Natural Gas
RNW	Renewable Northwest
SC	Sierra Club
SCC	Social Cost of Carbon
SPM	Special Public Meeting
TNC	The Nature Conservancy
UG	Oregon Utility Gas Proceeding
UM	Oregon Utility Miscellaneous Proceeding

1 NATURAL GAS FACT FINDING EXECUTIVE SUMMARY

Oregon has taken explicit steps to reshape the state's energy market by introducing Greenhouse Gas (GHG) emission reduction targets reflecting national trends to actively address climate change through state policy. Policies like the Oregon Department of Environmental Quality's (DEQ) Climate Protection Program (CPP) and House Bill (HB) 2021 set ambitious GHG emission reduction targets that will have a permanent impact on regulated utility investments and operations. In addition, trends related to climate change and climate adaptation are driving consideration of deep decarbonization pathways. These trends include the evolution of regional and national policies that cap or price GHG emissions and the rapid development and deployment of solutions designed to reduce energy related GHG emissions.

For the natural gas utilities overseen by the Oregon Public Utility Commission (PUC), the Environmental Quality Commission's 2021 adoption of CPP rules for DEQ represented a significant step in reorienting these utilities' near-term planning and future operations. By complying with the CPP, Oregon's fossil fuel suppliers – including the regulated gas utilities – must collectively achieve emission reductions of 50 percent by 2035 and 90 percent by 2050.

To assess the impact of the CPP on gas utilities, their customers, and other potential decarbonization activities, PUC Staff engaged in a dynamic, six-month public process of fact finding (UM 2178). The purpose of this Natural Gas Fact Finding (Fact Finding or NGFF) was twofold. The first was to conduct an initial analysis of the potential ratepayer bill impacts from the limiting of natural gas utilities' GHG emissions under the DEQ's CPP. The second was to identify appropriate regulatory tools to mitigate potential customer impacts and accommodate utility action.

To achieve these purposes, Staff collaborated with stakeholders, utilities, and expert consultants to identify CPP compliance pathways in a Draft Report, posted April 2022. The PUC then collected extensive public comment over the summer of 2022 on this draft. Concurrently with these efforts, the PUC conducted various public proceedings affecting natural gas utilities, including the completion of a major gas rate case, launched and/or completed two gas Integrated Resource Plan (IRP) dockets, and finalized the 2023 budget and action plan for Energy Trust.

Staff submits this Final Report to conclude this investigation. Our experiences and interactions with the Commissioners, utilities, and broad collection of stakeholders of these experiences and interactions have shaped this Final Report on the docket findings and suggested next steps for the PUC.

Broadly, our findings are that:

- Stakeholders bring **increasingly divergent approaches** to emission reductions, namely either limiting gas expansion or developing gas supply decarbonization innovations.
- CPP compliance **costs and risks** to gas customers from gas utilities' compliance actions range from manageable to rather substantial by 2029.
- CPP **compliance and decarbonization issues** that PUC activities will need to address are much better understood.
- A host of **regulatory tools** – identified and organized below under the categories of Planning, Programs, and Rate Making – are available to shape and manage the policy risks of various compliance pathways for gas utility decarbonization.

- A number of potential regulatory tools identified require an optimization across the energy system, rather than a focus on a single fuel (i.e., natural gas or electricity). Implementing such tools requires work across a variety of dockets and utilities and an unprecedented degree of **coordination and additional resources**.

Accordingly, Staff developed a set of regulatory tool recommendations that begin to address the identified issues given various constraints. The table below functions as a high-level summary of the near-term regulatory tools Staff recommends.

Table 2: Roadmap of Staff Regulatory Tools for Oregon (See Section 5.7 for more details)

Section 5 Analysis	Recommendation	Regulatory Tool		
		Planning	Programs	Ratemaking
Protecting Customers	Estimated Ratepayer Bill impact	X		
	Direct ETO to target programs to LI and EJ		X	
	Target IRA Incentives		X	
	EE programs to include transport		X	
	Assess CPP compliance risk in distribution system investments	X		X
	Explore rate impacts of accelerated depreciation in rate cases			X
	Transport customer cost of compliance in rate cases			X
Access and Info	Quarterly stakeholder Communications in UM 2178	X		
	RFA docket engagement through PUC AHD			X
Full Cost	Compliance costs into EE AC			X
	Develop marginal abatement cost curve	X		
	Utilities articulate electrification assumption in IRPs	X		
	Electrification info and data from DSP	X		
Decarbonization Planning & Cost-Recovery	Gas system maps with infrastructure age and depreciation information	X		
	IRPs include growth-related DSP investment details from Appendix F and provide analysis of demand-side options and non-pipe alternatives	X		
	Independent 3rd party analysis of key tech and market assumptions used by utilities	X		
	CPP as an acknowledgeable item in IRPs	X		
	Exploring IRP guidance from UM 2178	X		
	Follow Order No. 22-388 guidance regarding customer growth and compliance costs	X		X
Monitoring, Tracking, and Reporting	Utilities host annual presentation to PUC on CPP compliance filings	X		
	Purchased Gas Adjustment includes full CPP compliance costs			X
	Explore linking CPP amortization to CPP performance			X
Incentivize GHG Reductions	Explore use of SB 844 for emerging technologies	X		
	Pilot or Joint pilots with electric utilities proposals by 2025			X

The Final Report attempts to reflect participants' feedback and positions. Where applicable, Staff uses footnotes to indicate changes to actions or regulatory tools based on feedback or new learnings. The Final Report also includes a summary of Stakeholder Comments as Appendix E and has "Stakeholder

Insights" subsections and sidebars throughout the report to call attention to the perspectives of stakeholders on specific topics.

PUC Next Steps
This investigation and subsequent report created a foundation to shape the PUC's role relative to GHG emission reduction needs and policies in Oregon. The purpose was to better prepare Commissioners, stakeholders, and Staff for issues and positions that will arise across multiple dockets. Over the last six months of 2022, the PUC has already begun actively weaving early learnings from this Fact Finding and natural gas utility compliance with the CPP into existing dockets and activities.

The continued incorporation of the Fact Finding's regulatory tools serves as enhancements to the PUC's pursuit of the same goals that it has always had namely, to:

1. Determine whether the utilities have a least-cost, least-risk strategy, including for CPP compliance;
2. Ensure utilities are passing on to ratepayers only prudent and reasonable costs;
3. Set rates that represent reasonable balance of future risks and incentives between the company and ratepayers; and
4. Ensure that different customer classes are each allocated a reasonable proportion of the costs and benefits of utility service.

Going forward, as Staff learns more by incorporating NGFF recommendations and associated experiences into familiar regulatory proceedings, Staff may eventually recommend proactive new rulemakings or proceedings.

2 BACKGROUND

2.1 PUC'S NATURAL GAS FACT FINDING

The Oregon PUC requires utilities to plan and prepare for all risks, including new regulatory requirements, and to take action to mitigate customer risks in advance. In the natural gas sector, utility IRP planning has been considering for several years various decarbonization policy futures and how to develop a least-cost, least-risk strategy to comply with future policies. But, as state and national pressure for the gas sector to address climate began to build, the PUC took additional action and, in 2021, directed its Staff to conduct a "fact-finding" to lay a foundation for understanding the customer implications of decarbonization policy in the natural gas sector. Specifically for gas customers, the work plan proposed a study of the impact of the proposed DEQ CPP rulemaking to "understand the customer dimensions and impacts of different decarbonization scenarios and thus help in form future decision making."[1]

In June 2021, Staff officially opened this Fact Finding under Docket No. UM 2178. The purpose of this Fact Finding was to analyze the potential natural gas utility ratepayer bill impacts that may result from

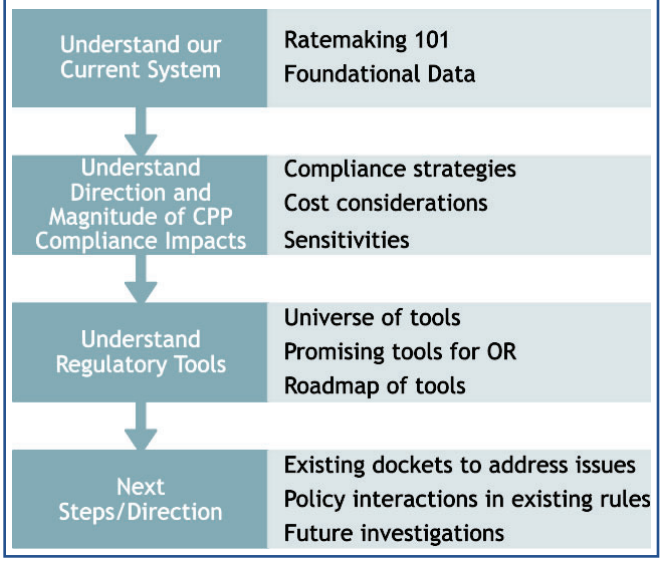
[1] To some extent Natural Gas Fact Finding work built on Staff's existing work plan to implement Governor Brown's Executive Order 20-04. See Oregon Public Utility Commission EO 20-04 Work Plans. Page 10. https://www.oregon.gov/puc/utilities/Documents/EO-20-04-Work_plans-Final.pdf.

limiting GHG emissions of regulated natural gas utilities under the CPP and to identify appropriate regulatory tools to mitigate potential customer impacts. It was crafted to produce two primary outcomes: 1) An understanding of potential natural gas ratepayer bill impacts associated with the CPP GHG emission target compliance; and 2) the identification of strategies and regulatory tools that equitably mitigate potential harm to natural gas customers while accommodating action that supports compliance.[2] The ultimate goal of the Fact Finding was to inform future policy decisions and other key analyses to be considered in 2022, once the CPP is in place.

The work plan (as outlined in Figure 1) was designed to:

- Help Staff and stakeholders understand current natural gas and cost recovery systems;
- Understand the potential impacts of CPP compliance;
- Explore applicable regulatory tools; and
- Identify actions the Commission could take to protect customers.

Figure 1: Natural Gas Fact Finding Process



Staff utilized a process that mixed facilitated workshops, public comments, and external analysis to develop an extensive set of documents.

Staff held six workshops, each of which was generally attended by over 90 people. In addition, the PUC offered multiple opportunities for public comment and access to utility compliance modeling workbooks. Staff also engaged the Regulatory Assistance Project (RAP) to assist staff and explore regulatory tools.

Staff's Draft Report was filed on April 15, 2022. By June 3, 22 groups provided feedback on the Draft Report and Staff received an additional 290 public comment emails outside of the UM 2178 docket. On July 12, the PUC hosted a Commissioner workshop and a subsequent Public Hearing to hear from stakeholders and to discuss issued raised in the fact finding and the Draft Report.

2.2 Natural Gas Use in Oregon

Oregon is served by three natural gas Investor-Owned Utilities. All operate as standalone gas companies in Oregon, with no retail electricity sales in the state. Annual sales revenues for Oregon's three natural gas utilities were over $810 million in 2019.[3] In 2019, Oregon's natural gas customers consumed about 1.6 billion therms, or about 4.4 million therms per day.[4] NW Natural is the largest of Oregon's three gas

[2] *See* UM 2178, Staff's Initial Application, June 8, 2021. Page 16 of pdf. https://edocs.puc.state.or.us/efdocs/HAA/um2178haa11959.pdf.

[3] 2019 Oregon PUC Statistics Book. Page 42. https://www.oregon.gov/puc/forms/Forms%20and%20Reports/2019-Oregon-Utility-Statistics-Book.pdf.

[4] Descriptive Statistics Excel Workbook, May 27, 2021. Available on Oregon PUC's Natural Gas Fact Finding webpage - https://www.oregon.gov/puc/utilities/Pages/EO-20-04-UP-FactFinding.aspx.

utilities, providing about 80 percent of total natural gas retail sales, with Avista Corporation (Avista) representing 12 percent of retail sales and Cascade Natural Gas (CNG) representing 8 percent.

Oregon's customers are divided into four categories: Residential, Firm Commercial & Industrial (Firm C&I), Interruptible C&I, and Transport. Firm C&I customers are generally small businesses, while Interruptible C&I customers are generally larger businesses. Transport customers are large, non-residential utility customers that have purchased their gas from another natural gas supplier (e.g., gas marketer) but who continue to use the regulated utility's distribution system to deliver their gas.

As can be seen in Figures 2 and 3,[5] while most natural gas utilities' revenues come from residential customers, much of gas delivered annually by these utilities is for transport customers. The revenues from transport customers to the regulated utilities is relatively small because these customers purchase their gas from gas marketers, not the utilities, and only use the utility's distribution system to deliver the gas to their location.

Figure 2: OR Natural Gas Utilities' 2019 Sales Revenue

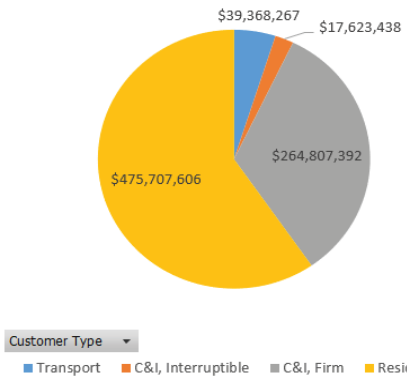
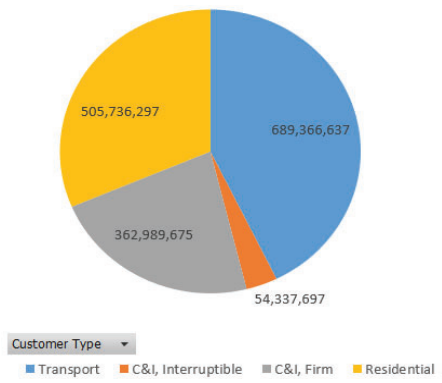


Figure 2: OR Natural Gas 2019 Delivery (Therms)



2.3 The Climate Protection Program

The CPP, effective in January 2022 (OAR Chapter 340 Division 271), is designed to substantially reduce GHG emissions in Oregon over the next thirty years. The CPP establishes a declining limit, or cap, on GHG emissions from fossil fuels used throughout Oregon, including diesel, gasoline, natural gas, and propane. This includes emissions from fossil fuels used in transportation, residential, commercial, and industrial settings. It also uses a best available emissions reductions approach for other site-specific emissions at facilities, such as emissions from industrial processes.

Companies regulated under the declining cap, known as covered fuel suppliers, include the three natural gas utilities and other suppliers of liquid and gaseous fossil fuels. The aggregate emissions covered under the CPP represent about half of the state's GHG emissions, with natural gas utilities making up 26 percent of total CPP covered emissions (NW Natural with 21 percent, and Avista and Cascade with

[5] *See* Descriptive Statistics Excel Workbook, May 27, 2021. Available on Oregon PUC's Natural Gas Fact Finding webpage - https://www.oregon.gov/puc/utilities/Pages/EO-20-04-UP-FactFinding.aspx.

3 percent each).[6] The 2022 cap is based on average emissions from 2017 to 2019 for the covered fuel suppliers. The CPP requires GHG reductions of 50 percent by 2035 and 90 percent by 2050.[7]

Covered fuel suppliers must demonstrate compliance every three years along a steady trajectory towards those two milestones in 2035 and 2050. The first compliance period is 2022-2024, with covered fuel suppliers first demonstrating compliance in November 2025. Companies demonstrate compliance by submitting one compliance instrument or community climate investment (CCI) credit (discussed in more detail below) for each ton of covered emissions reported in their annual GHG emissions reports to DEQ during the compliance period. Under the CPP, each natural gas utility receives a free annual distribution of compliance instruments based on their share of the overall declining emissions cap.

While DEQ prescribes exactly the number of compliance instruments that will be supplied to each natural gas utility in years 2022-2050, there are additional flexibility mechanisms. Covered fossil fuel suppliers can trade unused compliance instruments or bank them for future use. These companies can also optionally contribute funds to DEQ-approved third parties in order to receive CCIs that work similarly to the compliance instruments DEQ distributes (e.g., each CCI credit allowing supply of fossil fuels that when combusted emit 1 metric ton CO2 equivalent).

Covered fuel suppliers can earn CCI credits by contributing funds to third-party entities to implement projects that reduce GHG emissions in Oregon. The contribution amount for a CCI credit is established by DEQ. The contribution amount starts at $107 ($2021) per CCI credit and increases over time.[8] CCIs are designed to reduce emissions by at least one MT CO2e on average, prioritize benefits in or near environmental justice communities and reduce co-pollutants. CCI credits can be banked for two compliance periods and cannot be traded. Covered fuel suppliers can only use a limited number of CCIs to meet compliance obligations. The limit begins at 10 percent of total compliance obligations for the first compliance period and eventually grows to 20 percent by the third compliance period.[9]

In short, DEQ's CPP lays out a regulatory framework that reduces GHG emissions associated with natural gas by the three utilities. These amounts decline by 50 percent from the outset in 2022 by 2035, and by 90 percent by 2050. While there are some flexibilities such as trading and CCIs, these requirements represent a significant, rapid, and mandatory requirement in the reduction of the utilities' natural gas related emissions.

2.4 Stakeholder Feedback

Staff received feedback on its Draft Report in June 2022. Much of it indicated that stakeholders did not adequately see their positions and feedback represented. The Final Report attempts to better reflect participants' feedback and positions, and where applicable, language has been changed in response to this feedback. The Final Report also includes a summary of Stakeholder Comments as Appendix E and has "Stakeholder Insights" subsections and sidebars throughout the report to call attention to the perspectives of stakeholders on specific topics.

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[6] *See* Supplemental Cap Information Excel Workbook. Available on Oregon DEQ's Climate Protection Program website = https://www.oregon.gov/deq/ghgp/pages/climate-protection.aspx.
[7] *See* OAR 340-271-9000, Table 4.
[8] *See* OAR 340-271-9000, Table 7.
[9] *See* OAR 340-271-9000, Table 6.

Additional feedback on the Draft Report generally addressed the scope of the fact finding, utility modeling, the regulatory tools presented, action and regulatory tool prioritization, next steps, and the role of the PUC.

Staff attempted to strike a balance in scope that permitted for discrete analysis without omitting critical information. This was especially challenging in the case of how to consider electrification as an emission reduction strategy for gas utilities. Staff appreciates both the direction from stakeholders on this analysis, as well as the gas utilities' efforts to model electrification scenarios and impacts. That said, all parties appear to agree that the outcomes were inadequate. Staff has included more detail about the importance and challenges of modeling electrification with Oregon utilities.

Staff notes where it modified recommendations about regulatory tools based on stakeholder feedback. The Final Report also includes a new section on Stakeholder Insights on Prioritization and Next Steps. Staff appreciates stakeholder perspectives on the role of the PUC and captures this feedback in Appendix E but has not made further modifications to the Final Report based on this feedback. The most voluminous feedback came from environmental, climate, and environmental justice advocacy groups and associated grassroots organizations.

Table 3: Environmental, Climate, & Environmental Justice Advocacy Groups Feedback

Feedback	Staff Response
More direct action by the PUC to phase out gas and use electricity for space and water heating	As was clear throughout this proceeding, determining the role of electrification of space and water heating is paramount. Staff believes that its analysis, and utility planning, must expand to be able to provide guidance about when electrification is determined to be a least-cost, least-risk solution. Staff agrees that rigorous scrutiny and analysis of utility modeling and fuel decarbonization are critical elements of utility regulation. Staff recommends deploying an increased analytical focus on these topics, accompanied by expanded analytical capabilities to better evaluate and provide guidance on this topic in IRPs, procurement activities, and ultimately general rate cases.
Rigorous scrutiny and analysis of utility modeling and fuel decarbonization efforts	
Regulatory tools that focus on protecting customers, not gas companies	Staff included stakeholder guidance on prioritization to better reflect a focus on protecting customers. Staff also updated several near-term actions to reflect this prioritization.

We also heard from consumer groups such as the Alliance of Western Energy Consumers and the Oregon Citizens' Utility Board (CUB).

Table 4: Consumer Groups Feedback

Feedback	Staff Response/modification
Offered modifications and additions to the list of regulatory tools to be considered	Staff has attempted to capture this feedback in the applicable Staff Analysis sections, and notes where suggestions resulted in modifications.

Offered approaches for considering cost and risk allocation	
Presented different perspectives on the value or liability of existing and potential future infrastructure	Staff expands and updates section 5.4.3 on CPP Investments where there is further discussion of Line Extension Allowances and infrastructure investments to reflect both stakeholder feedback and recent PUC activities in rate cases and IRPs.
Presented perspectives on the role of renewable natural gas and hydrogen.	Staff incorporated additional stakeholder feedback on fuel decarbonization in Section 5.4.3 on CPP Investments where there is further discussion on decarbonizing supply. As noted above, Staff recommends heightened scrutiny and analysis of the role of decarbonized fuels in least-cost, least-risk planning, and expect that analysis will be informed by the best available science and information.

Last, we received feedback from Oregon's gas utilities and the gas industry.

Table 5: Gas Utility and Industry Feedback

Feedback	Staff Response
Reliability and cost concerns associated with electrification of heating loads	Staff has incorporated this feedback in the applicable sections of this report
The value of leveraging existing infrastructure in decarbonization efforts through decarbonizing fuels	
The near-term need to provide guidance on CPP cost recovery and develop EE programs for transport customers.	

Additionally, Staff found the guidance regarding prioritization of actions and next steps a valuable addition to this effort and include these insights below.

Prioritization

Stakeholders offered direction regarding how the Final Report and the PUC should prioritize its efforts. Staff notes that all commenters who spoke to this issue noted the need to prioritize near term GHG emission reductions and the need to provide clear direction on ways to protect customers. In addition, stakeholder providing the following feedback on prioritization:

Environmental, Climate, & Environmental Justice Advocacy Groups Feedback

- *Prioritization 1: Prioritize low-risk solutions that result in near term emission reductions via regulatory tools that support the deployment of existing, proven, established, and cost-effective tools, citing energy efficiency, weatherization, and electric heat pumps targeted to LMI customers. - TNC, NRDC, Multnomah County, JC - CS et al., and BE*

- *Prioritization 2: Prioritize Staff time by not developing pilots that focus on hydrogen or other nascent technologies. - JC - CS et al.*

- *Prioritization 3: Energy Efficiency and non-pipe alternative programs should prioritize GHG emission reductions by being fuel neutral and accommodating consideration of beneficial electrification. - TNC*

- *Prioritization 4: Solutions should be realistically available to achieve GHG reductions in the short term, and geared toward their best use. - JC - CS et al.*

- *Prioritization 5: Prioritize tools that can be implemented in the near term to protect customers. – NWEC*

- *Prioritization 6: Focus on protecting customers rather than preserving utility gas customers and allowing for system growth. - NWEC, TNC, and JC - EC et al.*

- *Prioritization 7: LMI-targeted electric heat pump deployment programs that bring resiliency co-benefit of cooling. - Multnomah County and JC - Mayoral*

Utility, Gas Industry, and Large Energy Customers

- *Prioritization 8: Regulatory tools should prioritize near term natural gas decarbonization efforts to meet CPP targets. - NWN*

- *Prioritization 9: Exercise caution and avoid hurried decisions in this time of heightened uncertainty and transition - JC - NWGA et al.*

- *Prioritization 10: Programs to help customers should be flexible, be allocated funds, and focus on low income and energy burdened customers. - CNG*

- *Prioritization 11: Protect customers, in part by protecting the viability of gas utilities to accomplish other GHG emission reduction goals. - NWN*

Stakeholder Recommended Next Steps

Staff heard stakeholders express a desire to see some explicit next steps and provided input about what those next steps could be.

NWN recommends and CNG stresses the PUC open a docket to address CPP compliance and cost allocation. CNG states the investigation should carefully consider the role of sending appropriate price signals. AWEC adds that the principles of cost causation should be maintained in rate spread approaches.

Avista, AWEC, NWN and JC - CS et al. describe the need to conduct an Oregon specific electrification study and provided details about what the study should include. This has also been referenced by other commenters as a beneficial electrification study.

CUB identified topics it had expected this investigation to investigate, which Staff believes can inform next steps. These include "no pipes solutions; line extension reform; useful lives and depreciation curves; discouraging incentives to switch from electricity to gas; reallocating investment risk; and fuel switching."

Staff is not opining on Stakeholder Recommended Next Steps but includes them here as part of the feedback received from Stakeholders and sees this as valuable information for the PUC to consider.

3 KEY FINDINGS, ISSUES, AND STAFF ANALYSIS

The compliance modeling, stakeholder dialogue, and discussion around regulatory tools in the Fact Finding led to several findings:

- Stakeholders bring **increasingly divergent approaches** to emission reductions, namely either limiting gas expansion or developing gas supply decarbonization innovations.
- CPP compliance **costs and risks** to gas customers from gas utilities' compliance actions range from manageable to rather substantial by 2029, depending on the customer and their existing level of energy burden.
- CPP **compliance and decarbonization issues** that PUC activities will need to address are much better understood.
- A host of **regulatory tools** are available to shape and manage the policy risks of various compliance pathways for gas utility decarbonization and the PUC most likely has sufficient authority to implement them.
- A number of potential regulatory tools identified in this Fact Finding would require an optimization across the energy system, rather than a focus on a single fuel (i.e. natural gas or electricity). Implementing such tools would require work across a variety of dockets and utilities over the next decade. For these reasons, these tools would require an unprecedented degree of internal and external **coordination and additional resources**.

3.1 DIVERGENT APPROACHES

Broadly speaking, two camps have emerged regarding the preferred approach to gas utility decarbonization. One group generally highlights the risks of gas system expansion and advocates to reduce or switch energy use away from the Oregon gas system. An opposing view generally proposes solutions that leverage the existing gas system through the accelerated deployment of gas decarbonization innovations such as methanated hydrogen and gas-powered heat pumps. This Fact Finding directly experienced this tension across the analysis and comments.

These divergent pathways for the gas industry are often described as being in opposition to each other. Although the Fact Finding confirmed this to largely be true, Staff finds that some combination of choices – between encouraging low-to-zero carbon gas technologic advances *in conjunction* with regulatory

actions that moderate future gas customer and infrastructure growth – may best balance among the various technology, cost, and regulatory risks associated with meeting the state's near-term GHG emission targets.

3.2 Modeling Costs & Risk

The structure of the NGFF allowed utilities and stakeholders to explore a wide range of possible compliance scenarios. As a result, participants were able to glean an initial understanding of the possible impact of various pathways, explore sensitivities, and begin the process of stress testing the reasonableness of underlying assumptions put forth by both utilities and various stakeholders.

As a foundation for all other analytic inquiries, Staff asked the gas utilities to model how they would comply with DEQ's CPP. Each utility modeled three overall CPP compliance scenarios (base case, high innovation, and accelerated electrification) with multiple sensitivities. The purpose of the modeling was to understand more about the cost and timing of the strategies the companies were contemplating to meet CPP GHG emission targets. By broadly understanding how utilities might comply and the associated costs and timelines for different strategies, the PUC, Staff and stakeholders might better understand where, when, and which regulatory tools might be used to mitigate costs and risks.

There were two general points of agreement:

1. Gas utilities will need to take significant near-term action to decarbonize: "Business As Usual" growth and operations of the system result in emissions exceeding the 2035 compliance targets.
2. Any compliance pathway will very likely increase the costs of energy service for all categories of customers over the next decade.[10]

3.2.1 Scenarios as Compliance Pathways

The gas companies were asked first to model how they might envision complying with the CPP, and then to consider a set of sensitivities, which were intended to stress test the company's proposed pathway. These sensitivities tested decarbonized gas availability, decreases in the number of customers, a more aggressive policy environment, and a reduction in availability of alternative compliance mechanisms. The gas companies were further asked to model scenarios with high electrification and high levels of support for innovation as different scenarios. A summary of the sensitivities and scenarios are in Table 6. Full descriptions can be found in Appendix A.

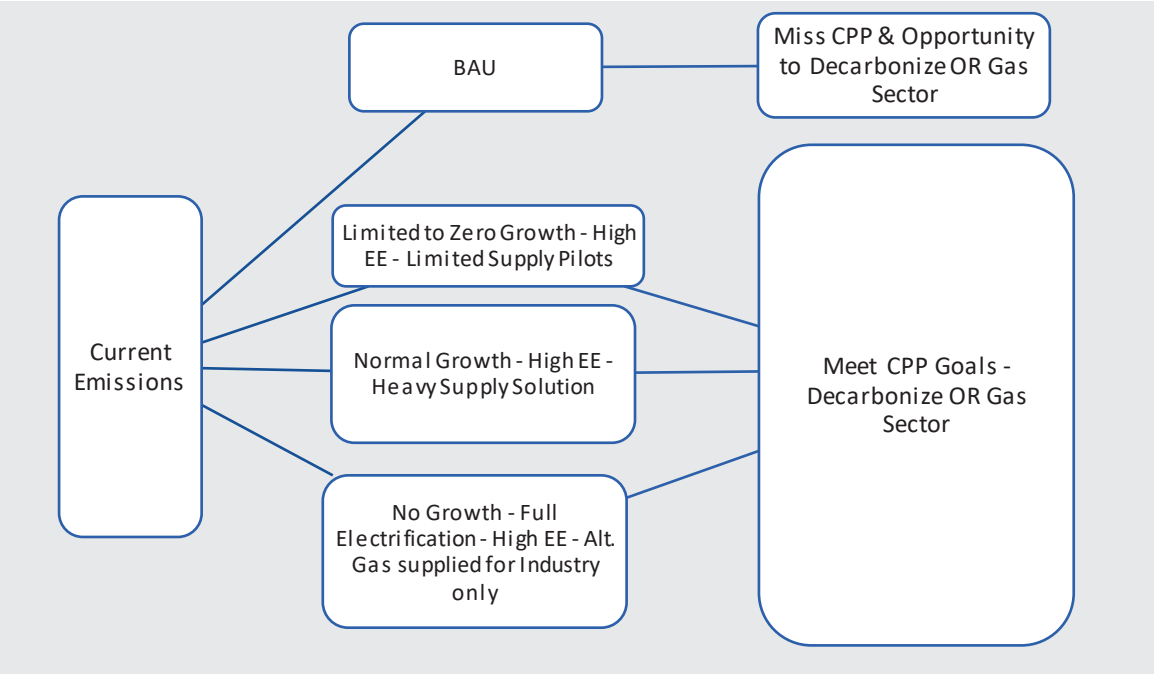
[10] As the only outlier, NW Natural's base case modeling actually projected slightly lower residential customer bills in 2050.

Table 6: Scenarios and Sensitivities

Scenarios	Base Case Scenario	Utilities model what they see as most optimal compliance pathways
	Alt. Scenario 1 – Innovation / Electrification / SCC	Modeled a Production Tax Credit for green hydrogen and syngas before 2026, use of higher Social Cost of Carbon, and high electrification of buildings
	Alt. Scenario 2 – Delayed innovation / Accelerated Electrification	Lower energy efficiency (EE) technology adoption curves, limited availability of RNG, and very rapid electrification of existing customers
Sensitivities	Declining Customer Counts	Modeled sensitivities that consider zero and negative customer growth
	Aggressive Timeline	CPP targets are advanced to align more closely with HB 2021: CPP targets 45% below baseline by 2030, 80% below baseline by 2040
	No CCIs	Modeled impacts of removing CCI compliance options
	Restricted RNG	Applied constraints on assumptions about the availability of RNG to meet emission reduction goals

The scenarios represent factors that are outside utility control, such as market and policy assumption variations. Scenarios combined with sensitivities test how well compliance pathways respond when market and policy factors differ from what was thought to be most likely as represented in the base case. The various scenarios modeled produced different compliance pathways. The uncertainty in costs, performance risks, and availability of resource options for each pathway to decarbonize has raised many more questions to be addressed to ensure the planning and decision-making process supports the identification of the least-cost and least-risk approaches to future GHG emission compliance. While the gas companies, stakeholders, policy makers, and regulators must chart a pathway to meet the CPP requirements, technology costs and performance remain highly speculative. The analysis from the NGFF, while informative, made it clear that more robust modeling and rigorous vetting of resource assumptions within IRPs would be required to make informed assessments about least-cost, least-risk paths for compliance.

Figure 3: Compliance Pathways



3.2.2 Lessons on Costs and Risks from Scenarios

While the modeling showed a general trend of increased ratepayer bills attributable to CPP compliance, it also often provided a wide range of results from which trends were difficult to detect. All parties agreed that the rigor and analysis that comes with a full IRP would be needed for more definitive modeling conclusions.[11] However, there were still many important learnings gleaned from the Fact Finding that we continue to find playing out in various dockets.

Perhaps more than anything, this exercise afforded stakeholders an opportunity to highlight concerns and challenge assumptions that will inform future IRPs.[12] Most notably, future IRPs must include rigorously vetted assumptions, and alignment with Staff and Stakeholders on the following topics to help assess least-cost/least-risk compliance strategies.

- Cost, feasibility, and ratepayer impacts of CPP specific compliance strategies;
- A need to understand the interdependency of the gas and electric systems in terms of costs and emissions that result from policies that shift load away from gas;
- The necessity to include transport customers in CPP compliance activities;.
- Costs of non-compliance, while not modeled, drives understanding of risk in future planning;
- Assumptions about the availability and cost of RNG;
- Cost, availability, timeline, and highest value use of hydrogen;
- Consistent modeling approaches for energy efficiency and associated avoided costs;

[11] The IRP presents a utility's current plan to meet the future energy and capacity needs of its customers through a "least-cost, least-risk" combination of energy generation and demand reduction. The plan includes estimates of those future energy needs, analysis of the resources available to meet those needs, and the activities required to secure those resources. *See* https://www.oregon.gov/puc/utilities/Pages/Energy-Planning.aspx.

[12] *See* Appendix B on Suggested changes to IRPs.

- Commercial readiness of proposed approaches (e.g. gas heat pumps);
- Data informing cost, benefits, and modeling guidance for beneficial electrification; and
- Load forecasts

Base Case

The Fact Finding's base case scenario was presented by each utility in September 2021 and represented a starting point for analysis.[13] Each base case reflected the gas utilities' preferred compliance strategies for residential, commercial, and industrial customers, given their most recent planning and what was understood about the CPP rules prior to adoption.

In the base case scenarios, annual ratepayer bills increased in the near term and showed a range of outcomes.[14] The estimated ratepayer bill increases varied across companies, customer types, and the assumptions made about future technology advances. Additionally, the rate and direction of ratepayer bill increase changed in later years of the model. CPP compliance costs to gas customers range from single digit percentages to rather substantial by 2025, depending on the customer and choices in the utility modeling. Figure 5 and Table 7 illustrate the estimated ratepayer bill impacts over time.[15]

Figure 4: Annual Ratepayer Bill Impacts in Base Case

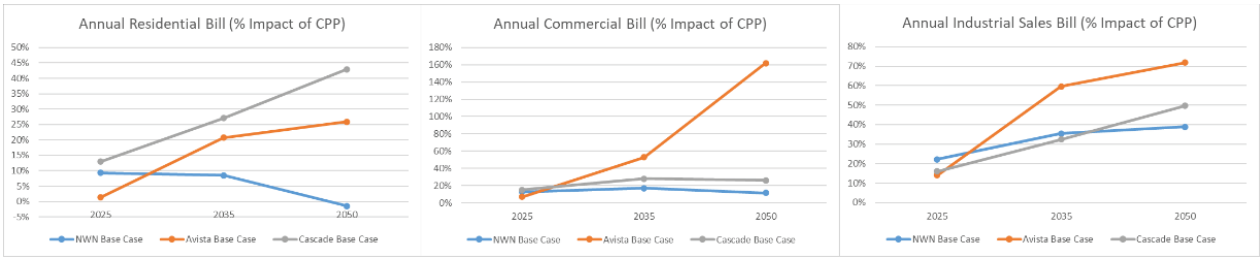


Table 7: Trends in Estimated Ratepayer Bill Impacts over Time

	2025			2035			2050*		
Util.	Res.	Com.	Ind.	Res.	Com.	Ind.	Res.	Com.	Ind.
AVA	1%	7%	14%	21%	53%	60%	26%	162%	72%
CNG	13%	15%	16%	27%	28%	32%	43%	26%	50%
NWN	9%	17%	22%	9%	17%	35%	-2%	12%	39%

*AVA and CNG only go to 2040 so those values were used in place of 2050

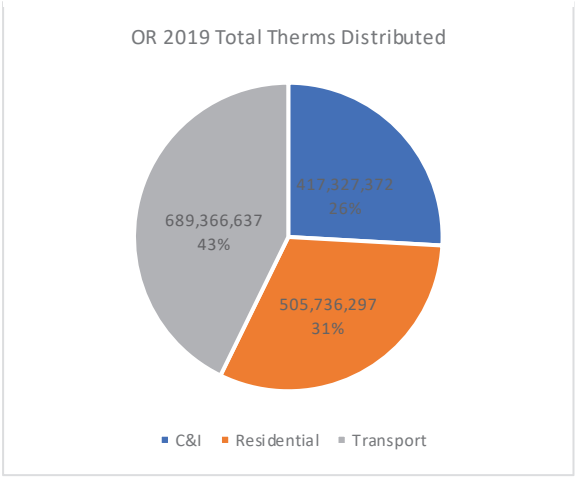
Transport Customers

Transport customers are customers that pay Oregon's gas utilities to transport gas to their location, but that pay a gas marketer, not the gas utility, for the actual gas commodity. However, it is the gas utility that is a regulated entity under CPP and is the entity through which transport gas emissions are regulated.

[13] *See* NGFF Workshop 3 presentations and link to modeling materials available on Oregon PUC's Natural Gas Fact Finding website – https://www.oregon.gov/puc/utilities/Pages/EO-20-04-UP-FactFinding.aspx.
[14] Avista notes that its compliance cost had been added to the price per dekatherm of natural gas available as supply into the Company's system and may not be indicative of actual rate spread.
[15] *Ibid.*

As can be seen in Figure 6, which simplifies customers into three categories, Transport customers accounted for over 40 percent of total therms distributed in 2019. With the adoption of CPP rules, the gas utility is now accountable for this large portion of emissions. This creates a situation in which the regulated gas utilities will need to consider developing more programs and activities aimed directly at reducing transport customers' GHG emissions and ways for those customers to pay for those programs.

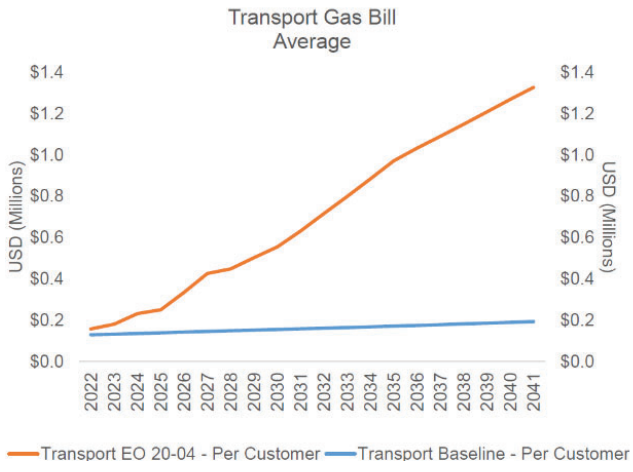
Figure 6: 2019 Total Therms Distributed



The regulated charges that transport customers pay to a gas utility represent a small portion of their total gas costs.[16] The additional cost to transport customers from their regulated utility for CPP compliance, on a $/therm basis, appears large on a relative basis as it is only compared to what transport customers pay now to the regulated gas utilities, which is the cost of moving their gas. It is important to note that rate spread determinations have not yet been established and how compliance costs would be spread across all customers has not been determined.

However, as an imperfect way to try to understand CPP compliance for transport customers, Staff pulled from the utility modeling how an evenly spread $/therm could manifest. As an example, Avista modeled price impacts to transport customers in its base case as seen in Figure 7. Transport customers see an increase in the average ratepayer bills they receive from the gas company, which reflects the increased cost of compliance per therm over the time horizon. Understanding how compliance costs could be spread is an open and unresolved issue that will need to be further explored in future cost recovery dockets. Additionally, transport load, as well as associated emissions and compliance costs,

Figure 7: Avista Base Case Transport Ratepayer Bill Increases due to CPP



[16] When representing the CPP compliance ratepayer bill impacts to these customers as a percent of the ratepayer bill impact, one only captures the increase to what transport customers pay to regulated gas utilities. It would not accurately represent the percent increase because it would not include the cost of the gas itself and the percent increase would appear very high, as compared to the total ratepayer bill paid to the regulated gas utilities.

have not previously been addressed in IRPs and will need to be captured in future gas IRPs.

Renewable Natural Gas

Assumptions about RNG (biogenic, hydrogen, and synthetic methane) costs and availability was also a topic of interest. Utilities modeled RNG use for compliance in all scenarios. Given the nascent market for RNG of various types, the use of RNG as a compliance strategy creates uncertainty and will require additional analysis of RNG costs and availability in future IRPs.[17] By 2025, the utility models projected RNG costs ranging from about $6/dekatherm to $12/dekatherm and these costs are assumed to decrease at different rates after 2025. For comparison purposes, natural gas is currently trading in a range of $3 to $5 per dekatherm.

Each of the three utilities came up with different assumptions about how much RNG they would be able to secure over time. These varying assumptions made it difficult to generalize about the costs and availability of RNG, as well as the impacts on future ratepayer bills. However, the use of neutral third-party market information about the RNG market and other nascent compliance solutions and technologies should provide a way to reduce uncertainty around compliance costs and risks in future IRP analyses.

Declining Customer Counts

Finally, modeling scenarios with declining customer counts provided limited insights. This may be due to inconsistencies in how each company modeled assumptions about how to handle the relatively fixed costs of existing infrastructure given a shrinking customer base. For example, Cascade's modeling showed the ratepayer bill impact from declining customer counts to be virtually unchanged when compared with its base case. Avista's model showed customer costs decreasing significantly in its declining customer count scenario when compared with its base case. Meanwhile, NWN's model showed a substantial increase in customer costs under its declining customer scenario. This reinforces the need to refine and standardize how such scenarios of declining customer counts should be modeled in future IRPs. The Table 8, summarizes the modeling results by scenario and sensitivity. More information on modeling results can be found in Appendix A.

Modeling Electrification

There was substantial disagreement about the consideration of electrification in the modeling. Staff provided initial electrification modeling direction in the Alternative Scenarios, and utilities followed with feedback on the challenges of this modeling. At stake were issues regarding what costs to include, how to assess ratepayer bill impacts, and concerns about reliability. Staff notes there is significant room for improvement

STAKEHOLDER INSIGHTS

MODELING ELECTRIFICATION

The costs of electrifications were not included in utility modeling, are unknown, and need further study - NWN *and JC – NWGA et al.*

Utilities modeled their ability to comply with CPP without relying on electrification - *NWN*

Load shifts from gas to electric could bring reliability risks in peak times - *Avista*

Reliability concerns are not supported and switching resistance heating to electric heat pumps would largely address load concerns – *JC – CS et al. and JC - MCAT*

Electrification might take longer than stakeholders who support it realize – *Avista*

Even swift moves toward electrification [of the gas system] take time to implement and [electricity] reliability concerns can be addressed in long-term planning – *JC – CS et al. and JC – MCAT*

[17] *See* RNG modeling recommendations for IRP in Appendix B.

in electrification modeling and that the electrification modeling for this fact finding is missing important cost and reliability elements.

Table 8: Scenario Modeling Summary

Scenario	Results – high level summary
Base Case	Generally, compliance with GHG emission regulations resulted in a range of both increased and decreased ratepayer bill impacts. The source of those ratepayer bill changes varied by company and compliance strategy. There is a lot of variation in the models, which reinforces the need to look at these issues more closely in the context of a planning document such as an IRP.
Restricted RNG	Restricting RNG had mixed results – NWN modeled increased RNG prices with the restriction, resulting in higher compliance costs compared to base case. Avista and Cascade reduced how much RNG was used for compliance, which reduced their overall cost of compliance compared to their base case scenarios.
Declining Customer Counts	NWN modeling showed customer declines result in increased compliance costs above those of its base case as the years progressed. Avista compliance costs decreased with declining customers and Cascade saw costs remain almost identical to its base case.[18]
Aggressive Timeline	NWN costs increased in the middle years of the model run but the difference between this scenario and the base case shrank as they approached 2050. Avista and Cascade's aggressive timeline model runs showed compliance costs consistently higher than in their base cases for all customer types.
No CCIs	All companies showed that the inability to use CCI's would result in higher compliance cost than in their base cases in the early years. But by 2050 the three utilities' modeling runs arrived at different conclusions with NWN's annual compliance costs continuing to outpace compliance costs in its base case, while Avista's cost differential was shrinking, and Cascade's annual compliance costs were the same as in its base case.
Alt. Scenario 1 - Innovation	Cascade's model resulted in ratepayer bill impacts that were lower than in their base case. Avista's modeling summary showed zero change in ratepayer bill impacts, but the workbooks showed negative ratepayer bill impacts for all customers except transport, and then compliance cost increases similar to those found in their base case. NWN's ratepayer bill impacts for the scenario increased significantly due to high electrification-related customer declines, which resulted in costs not tied to energy use being spread over many fewer customers (a 318% increase in non-energy charges in 2050). There was no increase in hydrogen usage on NWN's or Avista's system because the high electrification rates reduced or eliminated the need for fuel 'innovation.' Hydrogen usage was significantly decreased as a solution for Cascade when compared to its base case. For Avista, this scenario saw its transport customers pay an increasing share of the utility's compliance costs as the utility's retail customer count declined.

[18] Avista noted in their Comments to the Draft Report that their costs in scenarios with declining customer counts erroneously omitted ratepayer bill increase customers would face as fixed costs are distributed over fewer customers. This omission affected all high electrification and customer decrease scenarios. *See* Avista June 3, 2022, Comments in UM 2178.

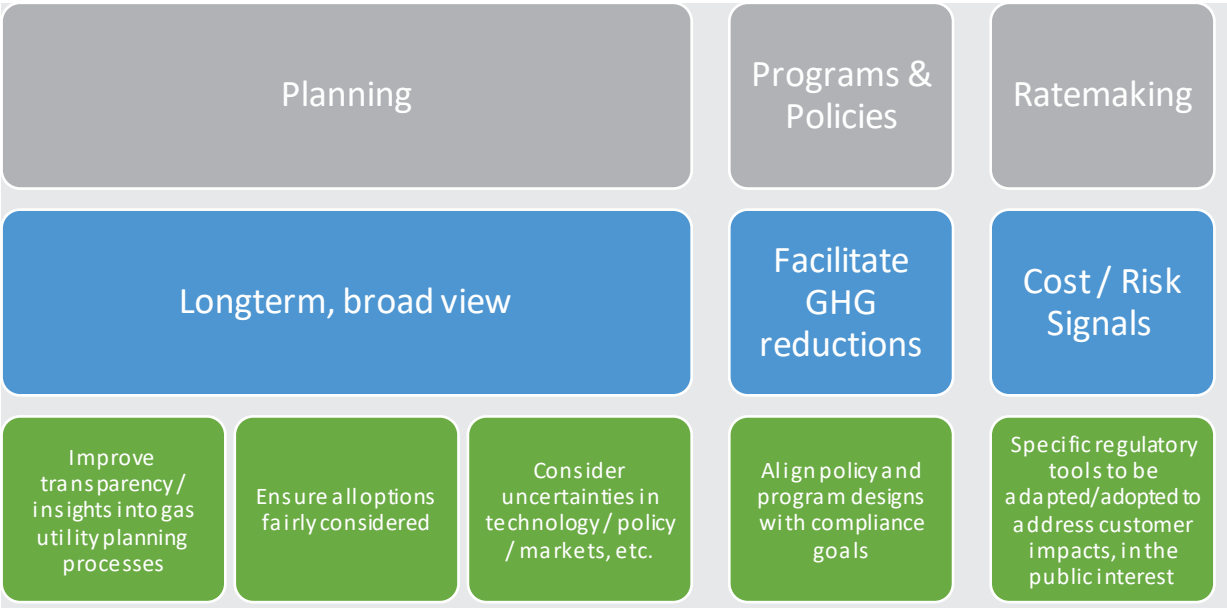
Alt. Scenario 2 – Accelerated Electrification	Like Scenario 1, Cascade modeled ratepayer bill impacts that were lower than their base case. Avista's summary showed zero ratepayer bill impacts, but the workbooks showed negative impacts in 2025 and then similar increases to the base case by 2035. NWN modeled the most aggressive electrification assumptions, resulting in a scenario that showed a significant drop in customers on the system and a 405% increase in residential bills by 2050. NWN also showed a moderate amount of industrial EE around 2035 and the use of banked allowance credits collected before 2042 for CPP compliance in the 2040s.

3.3 Regulatory Tools

In this proceeding, Staff, stakeholders, and utilities, led by the Regulatory Assistance Project (RAP), explored regulatory tools that could be used to address the customer impacts while meeting CPP targets.

Staff relied on a framework provided by RAP (summarized in Figure 8) to organize categories of tools and explore the benefits and tradeoffs associated with the different tools. These categories include three types of tools: planning, programs, and ratemaking. Additional information about these tools can be found in workshop 4a materials.[19]

Figure 8: Categories and Goals of Regulatory Tools



Staff believes current PUC authority is sufficient to apply all of the regulatory tools discussed in this report in the categories of planning, programs, and ratemaking as they are already being or have been implemented in some shape or form. These tools can support any number of CPP compliance pathways. However, some of the tools require new resources (e.g., reports, staffing, etc.), enhanced understanding

[19] See Docket No. UM 2178 September 24, 2021 Workshop 4a at:https://edocs.puc.state.or.us/efdocs/HAH/um2178hah101818.pdf

of costs and risks, and a coordinated, strategic focus to optimize decisions across Oregon's entire energy system, not just a single fuel type.

4 STAFF ANALYSIS AND RECOMMENDATIONS

The compliance modeling, workshops, and stakeholder input gave Staff an excellent set of raw materials from which to analyze costs, risks, and implementation options. The analysis and considerations below are meant to serve as an initial guide into the application of the identified regulatory tools.

Staff believes compliance with the CPP will very likely increase costs to all customers in the near-term and the modeling suggests it may have differing impacts. The extent of rate impacts depends upon the type of customer, compliance strategies deployed, and gas company characteristics.

While utility modeling showed a range of customer impacts from CPP compliance, in the absence of some form of intervention, the greatest burden from any increased ratepayer bills will likely fall to those already experiencing high energy burdens. All stakeholders involved in the workshops expressed concern about the potential impacts that will result from further burdening low-income and other at-risk customers. Further, the risk is not limited to gas customers. Initial analysis and research point to electrification costs, for either new or existing gas customers, spilling over into ratepayer impacts on electricity customers as well.[20]

The rate pressure risk grows beyond just the increasing cost of compliance for the existing system. Customer migration to the electric system, due to any number factors, spreads the cost of gas infrastructure over a smaller customer base. The potential for a feedback loop emerges, where a shrinking customer count potentially accelerates cost pressures, which further motivates those customers that can leave to do so. This problem also calls into question annual expansion of the gas system, as each new customer not only brings increased CPP compliance obligations, but also more gas infrastructure for future ratepayers to cover.

To understand this possible feedback loop better, Staff conducted its own investigation of residential customers' propensity to connect or disconnect from the natural gas grid.[21] Our research into the elasticity of residential demand confirmed two things: 1) Decisions to depart the system happen only after sustained price increases and generally lag those increases by two to three years, and 2) Cost increases will be felt more acutely by energy burdened customers because their options to respond to price signals are limited. Communications about the permanency of CPP compliance costs and Oregon's commitment to decarbonization may have an impact on the lag in gas consumer decisions.

Utility modeling confirmed that there could be significant cost impacts to commercial, industrial, and transport customers, not just residential customers. In short, CPP compliance has the potential to create rate pressure risks that could exacerbate energy burden issues for many types of customers. In light of this, Staff recommends regulatory tools that mitigate near-term price increases, limit long-term risks, and fairly manage any transition to new technologies. Potential solutions are discussed below, organized around various themes.

[20] Gridworks Central California Pilot of CPUC. https://gridworks.org/2021/09/lessons-learned-so-far-in-targeted-building-electrification/.

[21] See Appendix D – Elasticity.

4.1 Protecting Customers with Limited Options

Stakeholders identified two types of customers especially at risk from higher costs because they lacked the ability to easily substitute away from the natural gas system. Those two groups were low-income residential customers and businesses reliant upon gas for specific end-use processes. For low-income customers, higher costs create and increase an unavoidable energy burden. Some Oregon businesses have limited-to-no-economic substitutes to gas use for processes like emissions control technologies, outdoor heating for nurseries, and process heat to meet food safety standards. Tools that provide targeted mitigation of certain ratepayer bill increases, without hindering progress toward compliance, would be of high value to the process of gas system decarbonization. One such tool that has emerged since the Draft Report was published in April 2022, is the U.S. Inflation Reduction Act (IRA). Most notably for this section, the IRA has a generous set of rebates, via the High-Efficiency Electric Home (HEEH) Program, for low- to moderate-income households (i.e., ≤ 150 percent of Area Median Income), including up to $8,000 for electric heat pumps. Working with the administrator of these funds in Oregon to prioritize the use of IRA rebates for the gas companies' most vulnerable residential customers would go a long way toward protecting customers with limited options as the gas system seeks to decarbonize.

STAKEHOLDER INSIGHTS

PROTECTING CUSTOMERS

LMI-targeted deployment of electric heat pump deployment brings resiliency co-benefits of cooling - *Multnomah County and JC - Mayoral*

Focus on customer protections, not utility incentives - *NWEC, TNC, and JC - EC et al.*

Exercise caution and avoid hurried decisions in this time of heighten uncertainty and transition - *JC - NWGA et al.*

Protect customers, in part by protecting the viability of gas utilities to accomplish other GHG emission reduction goals. – *NWN*

Prioritize near term implementation of tools that protect customers – *NWEC*

Identify options for accelerating amortization schedules - *JC - EC et al.*

Deny rate recovery for investments in unproven technologies - *JC - EC et al.*

Implement rate class policies (e.g. HB 2475) - *JC - EC et al.*

HB 2475 is good, but insufficient protection - *Multnomah County*

4.1.1 Actions

To address a primary goal of this Fact Finding, Staff identified the following near-term actions that could help protect ratepayers from bill increases. Many of the comments from Stakeholders regarding protecting customers are also reflected in the priorities identified in Section 2.4, as well as throughout the NGFF report.

<u>Planning</u>

- Include estimated ratepayer bill impact analysis in IRPs to ensure transparency of trends and implications of compliance pathways as represented in portfolios.

<u>Programs</u>[22]

[22] The Draft Report previously included the recommendation: "Prioritization of incremental energy efficiency for CPP compliance that lowers natural gas usage but allows for customer count growth to continue at some level so as to avoid near-term outcomes that place upward rate pressures on those customers unable to exit the gas system and would therefore be forced to cover an increasing proportion of fixed costs." Staff decided to remove this action. The analysis in Cascade Natural Gas' IRP Update and the Commission decision on Line Extension

- Direct Energy Trust of Oregon (ETO or Energy Trust) and Community Action agencies to work with utilities to expand and target energy efficiency programs to low income and environmental justice communities to reduce energy burden and minimize anticipated ratepayer bill impacts.
- Assist in targeting IRA incentives and rebates, including but not limited to the installation of heat pumps as either a replacement for inefficient furnaces or in dual fuel configuration, for qualified low- to moderate- income households. Targeting includes securely providing data on customers to Oregon's IRA administrator(s) so they can prioritize rebates and incentives to these gas customers at risk from potentially elevated costs from ongoing CPP compliance activities and decarbonization investments.
- Ensure the gas utilities enroll transport gas customer into efficiency programs and that these customers pay their fair share relative to what other ratepayers pay for energy efficiency programs.

Rates[23]

- Include assessments of CPP compliance risks, like load growth from new customers, in prudency review of investments in the distribution system, in order to limit uncertainty around accumulation of long-term capital assets.
- Explore accelerated depreciation of unamortized investments in the gas utilities' next depreciation studies and provide a sensitivity analysis to better to understand rate impacts.
- Explore transport customer rate spread and rate design issues related CPP Compliance in general rate cases.[24]

4.2 Accessing Information and Proceedings

Stakeholders continually raised concerns about the complexity and resource commitment necessary to acquire key regulatory information and meaningfully engage in planning processes and other gas dockets. Much like the outcome of the PUC's 2018 Senate Bill 978 report,[25] community-based and business organizations interested in impacting PUC and utility CPP decisions noted the difficulty in achieving procedural inclusion across the spectrum of gas dockets.

Allowances in UG 435 underscored the several risks associated with continued system growth due to increased customer counts and that any associated benefits were more indeterminate and uncertain than previously thought in April of 2022.

[23] The Draft Report included the recommendation regarding the implementation of HB 2475 bill discount regime that will mitigate rate increases for energy burdened customers, in conjunction with aggressive energy efficiency." Staff removed this recommendation because it is currently being implemented.

[24] AWEC notes in its June 3 Comments that the principles of cost causation should be maintained in rate spread approaches.

[25] Oregon PUC. SB 978 – Actively Adapting to the Changing Electricity Sector. September 2018.

4.2.1 Actions

The following activities would improve stakeholder's access and awareness of gas utility's information and proceedings.

Planning[26]

- Facilitate stakeholder awareness of gas planning and CPP compliance related dockets through outreach coordinated by Energy Resources and Planning Division Staff, including, to the extent possible, how and when stakeholders could get involved.

STAKEHOLDER INSIGHTS

COMMUNICATIONS & ACCESS

Apply communication strategies to both gas and electric IRPs – *NWN*

Staff should produce manuals on effective participation – *JC – CS et al.*

Ratemaking

- Encourage parties interested engaging in rate cases to work with PUC's Administrative Hearings Division's efforts to expand eligibility for intervenor funding to fund participation in PUC proceedings.

4.3 Full Cost of Aggressive Demand Reduction – Load Shift Impacts of Electrification

Many stakeholders put forth ideas to rapidly reduce customer demand to meet CPP targets. These range from energy efficiency to Beneficial Electrification (BE).

Energy Efficiency Avoided Costs

The calculation and application of energy efficiency avoided costs is a key input in planning as it dictates what energy efficiency measures are deemed cost effective. Many stakeholders pointed to the important role of Energy Efficiency Avoided Costs (EE AC) in facilitating cost-effective GHG emission reductions. This included comments on the inclusion of CPP compliance costs, consideration of avoided gas infrastructure, consideration of climate impacts, and capturing non-energy benefits.

STAKEHOLDER INSIGHTS

EE AVOIDED COSTS (AC)

CPP compliance costs should be reflected in EE AC – *CNG and NWN*

AC in NWN's current IRP and AC filings will reflect CPP costs – *NWN*

EE AC should reflect avoided gas infrastructure costs – *TNC*

Include AC of climate impacts and non-energy benefits – *Multnomah County*

Beneficial Electrification

BE emerged as a key concept in UM 2178. The Regulatory Assistance Project (RAP) offers this description of beneficial electrification:

> For electrification to be considered beneficial, it must meet one or more of the following conditions without adversely affecting the other two: 1) Saves consumers money over the long run; 2) Enables better grid management; or 3) Reduces negative environmental impacts.[27]

[27] Farnsworth, D., Shipley, J., Lazar, J., and Seidman, N. (2018, June). Beneficial electrification: Ensuring electrification in the public interest. Montpelier, VT: Regulatory Assistance Project.

Multiple stakeholders pointed to the role electrification can play in near term emission reductions, the need to consider the likelihood of future electrification policies and actions, as well as equitable transitions via building electrification and associated co-benefits in the planning process. However, there was substantial stakeholder conversation about whether and how electrification should be considered as a strategy for reducing emission or a regulatory tool. For residential customers, this may include replacing gas fired furnaces, stoves, and water-heaters with those powered by electric heat pump and induction technology. For commercial customers, this may include swapping an existing gas-fired boiler for an electric boiler. Much is unknown about how to deploy BE in Oregon and what the resulting emissions and cost impacts might be to the electric system. Without careful analysis, planning, and execution, electrification has the potential to shift greater energy demand, peak risk, distribution costs, and reliability concerns to electric ratepayers. Most stakeholders acknowledged that more must be learned to understand the costs and risks from electrification so that with good planning, electrification could create system benefits.

To this end, Staff has engaged two consultants to begin exploring some of these topics. First, in LC 79, Synapse will be exploring ways to add electrification costs to gas IRP. The intent of the study will be to provide information for a conversation about the costs of electrification scenarios as compared to other decarbonization pathways. Second, through a generous grant from the US Climate Alliance, the Cadmus Group and Moment Energy Insights will conduct a technical study to inform **future** gas and electric IRPs with guidance on information requirements to facilitate joint utility decision making for least-cost, least-risk GHG emission reduction strategies.

STAKEHOLDER INSIGHTS

BENEFICIAL ELECTRIFICATION

Electrification policies as a compliance pathway eliminate customer choice - *JC - NWGA et al. and NWN*

Electrification can play a role in near term emission reductions, there is a high likelihood of future electrification policies and actions, and building electrification can be part of an equitable transitions due to associated indoor air quality co-benefits with direct impacts to Black, Indigenous, and other Environmental Justice communities - *SC, NWEC, Multnomah County, JC - CS et al., and CUB*

The biggest risk of potential customer decreases and associated rate pressure increase are not from gas company compliance costs, but rather from policies that would drive customer defection - *NWN*

While electrification is a preferred strategy for building decarbonization, the Commission should be prepared to protect LMI gas customers from anticipated negative cost impacts - *SC, NWEC, Multnomah County, JC - CS et al., and CUB*.

Conduct electrification study - *Avista, AWEC, NWN, and JC - CS et al.*

Create a timeline for building electrification, ensure targeting incentives for phased electrification and decommissioning of gas - *JC – MCAT*

The Commission should develop and provide direction about how gas companies should consider electrification in IRPs and analysis of stranded asset risk - *JC - CS et al*.

Electrification should not be considered as a 'regulatory tool' - *AWEC, NWN, Avista*

Sources cited to support electrification were too generalized or based on states with very different attributes and should not be relied upon for assessing electrification impacts and costs and, that because the case for electrification is unsupported, that inclusion as an option sends 'calamitous' market signals – *NWN*

4.3.1 Actions

Staff believes the following tools could be used to facilitate coordination between gas and electric utilities to enable analysis of customer costs, grid management, and emission impacts of load reduction associated with aggressive gas demand reduction.

Planning

- Develop marginal abatement cost curves for IRPs that identify all resources potentially used by utilities in CPP compliance, including currently non-cost effective energy efficiency.
- Request gas and electric utilities to develop and articulate individual electrification assumptions in future gas and electric IRPs that others can reference, based on feedback from Staff's two sets of consultants exploring different aspects of this issue.
- Work with electric utilities in future DSP filings to identify the cost elements, costing methodology, and estimated average distribution cost to electrify existing gas customers.

Programs

- Adopt a compliance cost of carbon and an enhanced risk reduction value into gas energy efficiency avoided costs that reflects CPP-related risks in order to accurately value and support energy efficiency opportunities and investments so as to encourage more aggressive demand reduction.

4.4 Decarbonization Policies as Key Determinants to Planning and Cost-Recovery

The GHG emission reduction targets with the passage of HB 2021 and the adoption of the CPP rules reshaped Oregon's energy policy landscape. Resource planning will increasingly require systems thinking across all utility types.[28] Utilities, stakeholders, and the PUC will need to consider the energy system on a whole and ratepayers as households. Key policy decisions can easily have consequential, systemwide feedback loops that span beyond an individual gas or electric utility's IRP or operations. Yet, understanding impacts across utilities proves challenging in Oregon's resource planning environment as interplaying impacts are not readily apparent or captured by the current planning processes.

Energy System Planning

Attempts to model interactions between gas and electric utilities as part of this investigation proved to be beyond the limitations of the NGFF modeling. It also showed how difficult it would be to analyze the costs and benefits of strategies that contemplate shifting heating loads from gas to electric in Oregon as part of a single fuel utility's IRP. To meet the state's GHG reduction targets and avoid unnecessary costs and reliability risks, the planning of both gas and electric utilities will require the sharing of key data in the near-term and the explicit recognition of planning interdependencies. Conducting least-cost, least-risk analysis to determine the best solutions to reduce GHG emissions requires the ability to

STAKEHOLDER INSIGHTS

ENERGY SYSTEM ANALYSIS

Energy system analysis should be a formal coordination planning process, beyond just shared assumptions and data - *TNC*

Develop combined IRP to identify how loads can be met most cost effectively, rather than how companies can best meet loads for their customers - *NRDC*

Gas utilities should collaborate with electric Distribution System Planning on joint planning efforts - *NWN and CNG*

Commission should task a third party to oversee a new joint planning process - *JC – CS et al.*

Joint utility planning scope should closely engage with electric utility to understand cost and reliability information to holistically understand costs of gas decarbonization - *NWN*

[28] Systems thinking is defined as a way of making sense of the complexity of a situation by looking at it in terms of wholes and relationships rather than by splitting it down into its parts.

understand trade-offs across different types of energy utilities (gas or electric) that share the same customer.

Stakeholders provided guidance about what energy system planning ought to include, some of which is referenced in the section on Full Cost of Aggressive Demand Reduction. However, there was general agreement that there is a need for a more holistic understanding of the interactions between gas and electric utility planning.

4.4.1 IRPs - Guidelines & Improvements, Assumptions, and Acknowledgement

Oversight of Oregon's gas utilities meeting DEQ's CPP requirements in a least-cost, least-risk manner is part of the PUC's broad mandate. Much of this oversight begins with the IRP development and review. The PUC IRP process requires utilities to produce plans that adhere to the PUC's IRP Guidelines, which were established in 2007.[29]

Stakeholders called out that there may be a need to revisit the IRP guidelines and providing input on how such a process could take place. They highlighted an interest in further discussion about the IRP elements proposed in Appendix B and where methodologies should be clarified and how assumptions should be supported. The issue of assumption validation and support was raised as part of the conversation around IRPs generally, as well as specifically with regard to decarbonizing supply. Comments regarding decarbonized supply are addressed in the following section regarding CPP investments and section 5.5 regarding Risk and Uncertainty.

STAKEHOLDER INSIGHTS

IRP GUIDANCE AND GUIDELINES

Update Guidelines to better capture emerging risk and uncertainty and require analysis of fuel switching – *Joint Climate Solutions Pre-June 3 Comments*

Open a separate proceeding to address changes proposed in Appendix B regarding IRPs, consideration of marginal abatement cost curves, and modeling assumptions - *NWN, CNG and AWEC*

Commission should work with Companies and stakeholders to develop a uniform methodology for converting IRP investments into estimated ratepayer bill impacts - *CNG*

CPP compliance should be acknowledgeable in IRPs. *CNG and NWN.*

CPP compliance should be mandatory, not just acknowledgeable. *JC - CS et al.*

Group method accounting means utilities do not track all assets or depreciable life and is not consistent with publicly available data from depreciation studies – *Avista*

Mapping may be a security issue – *NWN and Avista*

4.4.2 CPP Investments

Infrastructure and Line Extension Allowances

Infrastructure investments may be related to "safety or generally system reliability" or "customer growth or reliability related to growth." As noted above, system growth brings both additional GHG compliance obligation and infrastructure costs with long depreciation timeframes at risk from uncertainty around the number of customers. Many stakeholders commented on the need for heightened scrutiny of investments in gas infrastructure. Comments ranged from the value of using existing infrastructure for innovative fuel decarbonization options, to concerns about the risk of stranded costs associated with long term investments, as well as an interest in strategic system contractions with electrification.

[29] See Order Nos. 07-002 and 07-047.

During the course of this investigation, the topic of how to consider infrastructure investments was raised in Cascade Natural Cas's IRP Update, LC 76. In that docket, Staff noted that:

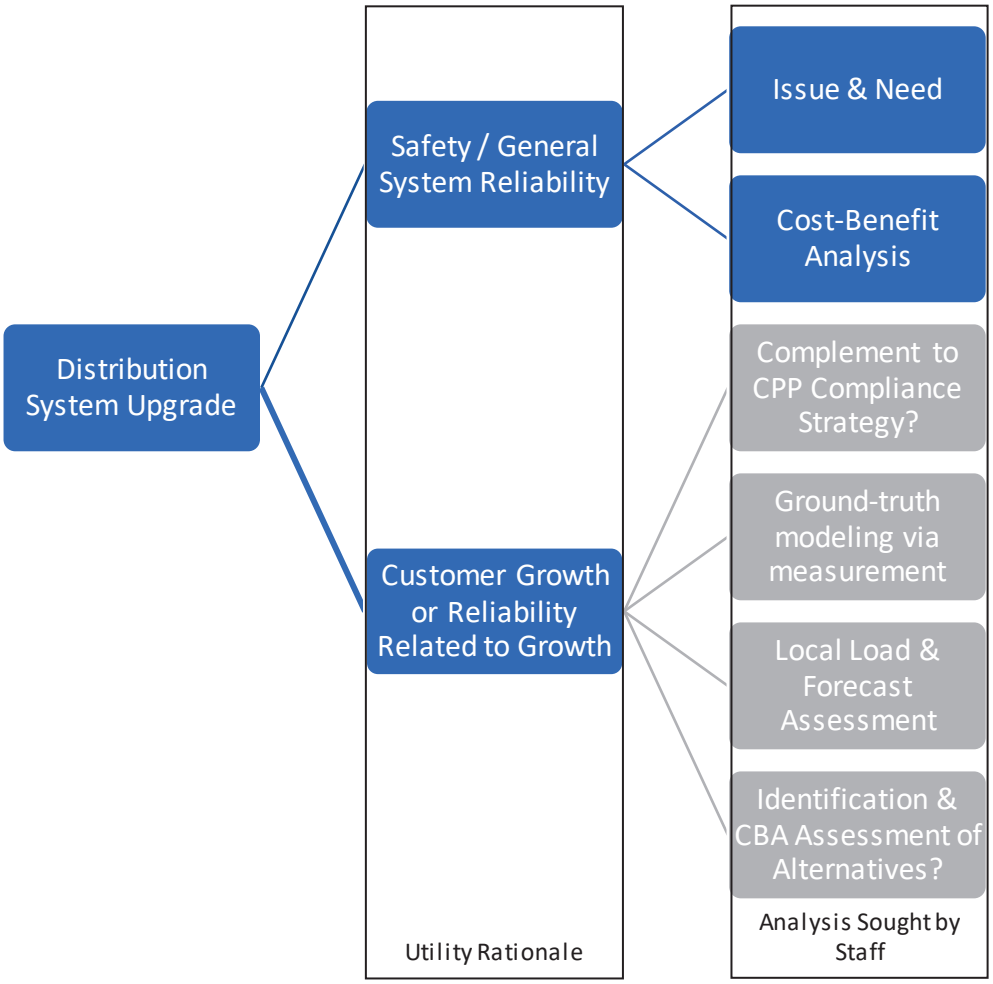
> [g]rowth in natural gas demand requires compensatory investments or actions to stay in line with the CPP's steadily declining trajectory of annual emissions. Determining the acknowledgability – and potentially even the prudency – of distribution upgrades now requires an understanding of the absolute need for any proposed upgrade *and* of how that upgrade fits within the company's system-wide CPP compliance plan, both in the near- and long- term.[30]

In that proceeding, CUB also called for CNG to begin piloting "alternative approaches to distribution system upgrades, like targeted energy efficiency and demand response, to more fully consider non-pipe alternatives in future resource planning."[31]

Staff's comments above presented a high-level framework for how Staff plans to assess gas LDC's proposed distribution system upgrades going forward with new criteria found in grey in **Error! Reference source not found.**9.[32]

[30] See LC 76 Cascade IRP Update, Staff Final Report, October 7, 2022, page 5.
[31] See LC 76 Cascade IRP Update, CUB Comments, July 22, 2022, page 4.
[32] See LC 76, Staff Comments, July 22, 2022, page 11.

Figure 9: *Staff's Proposed Approach in Cascade's IRP Update (LC 76) to Distribution System Project Analysis Post-CPP Adoption*



The grey boxes represent new criteria Staff proposed to use when assessing distribution system projects driven by future customer growth. Appendix F details specific information Staff would request on any growth-driven distribution system project in the future. As Staff learns more and engages with IRPs and stakeholders, we envision this framework evolving.

In addition to the infrastructure issues raised in LC 76, the issue of line extension allowances (LEA) was raised in NW Natural's rate case, docket UG 435. In UG 435, CUB raised CPP compliance obligation costs associated with LEAs for new customers and successfully argued for modifications to the PUC's LEA for NW Natural. In summarizing CUB's argument, the PUC noted that:

> CUB maintains that as the system grows, the costs to reduce emissions to comply with the CPP will also increase. * * * CUB asserts that * * * under a traditional paradigm adding new customers mitigates cost impacts, it is not true when new customers bring additional emission reduction costs to all customers. * * * [U]nder the CPP, NW Natural must reduce its greenhouse gas emissions by 50 percent from a historic baseline, but that as the system grows, NW Natural will have to reduce baseline emissions by 69 percent to accommodate the load growth and still meet the emissions reduction requirements. CUB argues that this increases the costs to existing customers. * * * CUB maintains that NW Natural is seeking to significantly increase its energy efficiency spending to reduce therms while also spending millions on capital investments through the LEA to increase therms. CUB asserts that therms from existing customers are different than those from new customers, because it takes decades to pay back LEA spending and it is more cost effective to not subsidize growth through the LEA than to pay incentives to customers to reduce usage. CUB contends that NW Natural is asking customers both to pay to grow the system and pay for energy efficiency incentives.[33]

STAKEHOLDER INSIGHTS

INFRASTRUCTURE

Immediately halt gas system expansion – *CUB, JC-EC et al., MCAT Joint, and OSPR*

Addition of new gas customers creates a stranded cost risk – *CUB*

NWN Disputes the claim that investments in gas infrastructure will lead to stranded assets - *NWN*

Support decarbonization polices that embrace innovation and make use of existing energy delivery infrastructure - *JC - NWGA et al.*

Investigate opportunities to "branch pruning" sections and replace with electrification - *JC-EC et al.*

LINE EXTENSION ALLOWANCES

Eliminate or phase out Line Extension Allowances for gas and revisit those that consider behind the meter upgrades supporting electrification- *JC-EC et al. JC-CS et al., TNC*

Growth of gas customers is unsustainable and incentives should align to protect customers associated with gas customer declines - *TNC*

LEAs should be based in sound economic and rate making principles (equity among rate

The PUC agreed with CUB on this issue and stated:

> The primary reason that NW Natural's current LEA is problematic is that it fails to take into account any of the costs that are brought to NW Natural's system from new customers associated with greenhouse gas emission abatement obligations placed on the company under the CPP. As shown in this case, those costs could be significant. In fact, the record demonstrates that those costs, when accurately accounted for, could result in no or negligible economic benefit being brought to the existing system from the addition of new customers.[34]

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[33] *In the Matter of NW Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Order No. 22-388 at 34 (October 24, 2022)(fo*otnotes omitted*).
[34] *Id*., at 48 (footnotes omitted).

This PUC's decision signals awareness of increased risks of new customers and that this is an area worthy of heightened scrutiny in both planning and cost recovery dockets.

The PUC also provided guidance relevant to CPP compliance costs and customer growth in its decision Order No. 22-388. Guidance from this rate case will be valuable to analysis in the integrated planning process. Specifically:

- Conducting analysis of how each new customer addition changes the costs of CPP compliance for other customers; and
- Reviewing analysis supporting the company's assumptions about the expected time frame over which new customers will remain on the system, and how changing policy dynamics are factored in.[35]

Decarbonizing Supply

RNG, green hydrogen, and synthetic methane represent relatively new supply side additions to natural gas planning in Oregon. Being conservative in projecting costs and availability (both volumes and timing) of emerging solutions/technologies can help manage uncertainty related to the relative unpredictability of these variables, especially for nascent technologies like hydrogen and synthetic methane.

Stakeholders expressed concern about the assumptions of availability and cost of RNG as modeled by the gas utilities. Stakeholders noted discrepancies between the availability cited by the gas companies and that provided in a recent ODOE report, and further questioned the availability assumptions used by the gas companies. They indicate that biomass sources will be difficult to access and costly. These stakeholders urged Staff to provide heightened scrutiny to utility RNG modeling and assumptions.

If RNG and H2 are to be used, stakeholders suggested additional backstops and guardrails to help protect customers, including information about current and future development sites, confirmation that Renewable Thermal Credits can be used for CPP compliance, and close tracking of RNG market potential. It was also suggested that the PUC should not allow expansion of the gas system unless utilities can demonstrate their ability to acquire RNG and Green H2 in a cost competitive manner, and that they can demonstrate the safe use of H2 before approval of any rate-based incentives.

Alternatively, NWN argued that utility activity is a driver of markets, so we should be careful in assuming that general market reports reflect what is possible in the region. Further, both NWN and CNG support use of SB 844 to incentivize H2 deployment.

STAKEHOLDER INSIGHTS

DECARBONIZING SUPPLY

Only Green H2 should be modeled, conservative assumptions should be used regarding availability and cost, and RNG and H2 should be reserved for hard to electrify end uses. - *JC-MCAT et al., JC-CS et al.*

RNG commits customers to gas home heating equipment and eliminates opportunity to electrify - *NRDC*

Market adoption of RNG may be different across locations and demographics - *CNG*

RNG development activity and markets should be tracked closely, and all RNG must be CPP compliant - *JC - CS et al.*

Do not expand the gas system until utilities can demonstrate that RNG can be acquired in a way that is cost competitive and safe – *Multnomah County*

National or general assumptions about RNG do not reflect large utility influence on the market – *NWN*

SB 844 could be a tool for developing H2 – *NWN and CNG*

[35] See UG 435, Order No. 22-388, page 52.

Cost Recovery

The issue of cost recovery associated with CPP compliance was raised by several stakeholders.

NWN, CNG and AWEC expressed concern about limiting cost recovery options for CPP compliance and stated that ensuring adequate cost recovery was critical to maintain safety and reliability, and the ability to bring lower carbon fuels on to the system, like H2. They also expressed concern about connecting cost recovery with CPP compliance.

JC – MCAT *et al.* recommended the PUC deny cost recovery for high-cost and high-risk investments in unproven technologies.

STAKEHOLDER INSIGHTS

COST RECOVERY

Ensuring adequate cost recovery is critical for maintaining safety and reliability and cost recovery should not be limited to CPP compliance – *NWN, CNG, and AWEC*

Deny cost recovery for high cost, high risk investments in unproven technologies – *JC-MCAT et al.*

4.4.3 Actions

To meet the state's GHG reduction targets and avoid unnecessary costs and reliability risks, the IRP for both gas and electric utilities will require the sharing of key data and the explicit recognition of planning interdependencies, the inclusion and review of new information reflecting various supply and demand side compliance approaches, an expansion of data regarding distribution system investments associated with growth, and compliance costs and risks. To address these issues Staff identified the following applicable near-term actions:

<u>Planning</u>

- Make publicly available maps of the gas system overlaying depreciation and age data and include lists of infrastructure and associated depreciation schedules.
- In IRPs, gas utilities should support proposed growth-related distribution system planning investments with analysis and details proposed in Appendix F and ensure that modeling said investments allows them to compete comparably with other demand-side options and non-pipe alternatives.
- To inform utility planning, the PUC should contract with an independent third party (*e.g.*, consulting firm or regional non-profit like NEEA) on a regular basis to evaluate market trends around alternative fuel and low-carbon technology cost and availability and to analyze Pacific Northwest market adoption of decarbonization technologies that are central to any utilities' CPP compliance pathway.
- Staff to treat CPP compliance as an acknowledgeable element of any future gas IRP or IRP update.
- Staff recommends exploring in the future the use of the IRP guidance found in Appendix B. Staff will seek a waiver to adopt this new guidance where it conflicts with existing IRP guidance in Order Nos. 07-002 and 07-047 or existing GHG planning guidance in Order No. 08-339.
- In IRPs gas utilities should include or conduct similar analysis to that directed in Order No. 22-388 regarding two items. First, new customer addition costs and risks to existing customers for CPP compliance. Second, supply analysis regarding new and existing customer retention and how changing policy dynamics are factored in.

4.5 Robust Compliance Monitoring, Tracking, and Reporting

Each utilities' base case CPP compliance modeling relied on decarbonizing the fuel they provide through large amounts of RNG, green hydrogen, and/or synthetic gas. These supply-side alternatives to natural gas currently represent a significant part of each companies' compliance strategy. Notably, large-scale hydrogen availability at a reasonable price is necessary in less than 15 years.

Table 9: Alternative Supply Projections

Utility	RNG Supply Penetration by 2025[36]		RNG Supply Penetration by 2035	
	Volume (Dth/year)	% Of Deliveries	Volume (Dth/year)	% Of Deliveries
Avista	317,875	2%	2,932,134	40%[37]
Cascade Natural Gas	1,544,229	10%	6,673,003	26%
NW Natural	4,842,842	4%	8,399,503 (bio) 13,551,224 (H2)	23%

Many stakeholders believed the quantities and the timeline of availability put forth by the companies were not realistic. Further, they made the case that relying on these natural gas alternatives placed a tremendous amount of compliance and financial risk on the companies, and thus ratepayers. It allows for the continued expansion of the gas system with the promise of future low-to-zero GHG fuel supplies. To inform risk assessments robust monitoring, tracking, and reporting of trends from Oregon activities and the broader market will be necessary to inform compliance risk in planning dockets and rate cases.

Strategies reliant on solutions with high levels of uncertainty (*i.e.*, abundant, carbon-neutral, and low-cost synthetic methane) function amidst a backdrop of uncertainty: the risk of non-compliance with the CPP. The compliance regime for the CPP has already begun. In just over three years, the DEQ will close the first compliance demonstration window and assess fuel supplier performance, including the gas utilities.

CPP rules grant the DEQ broad discretion to impose penalties for enforcement.[38] While the DEQ has not yet announced how it will apply penalties, Staff's operating assumption is that the floor of any non-compliance penalty should be at least the cost of a CCI on a per metric ton basis. For the current three-year compliance period, the average cost of a CCI as an alternative compliance mechanism will be approximately $108/metric ton, unadjusted for inflation. However, stakeholders argued the cost of non-compliance should be double or triple the price of a CCI.

Regardless, imposing a penalty at the CCI price on a per metric ton basis poses a potentially sizeable, near-term, financial risk to the gas utilities. The table below attempts to characterize this financial impact should the utilities exceed their three-year emissions allowance by just 1.5 percent.

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[36] RNG Supply Penetration refers to all renewable supply options, including biofuel, hydrogen, and synthetic gas.
[37] Avista noted in comments that it believes this value should 19.5 percent of deliveries. However, Staff notes that the value provided by Avista appears to be its 2030 value, not 2035, which is what the above table is intended to capture.
[38] OAR 340-271-0010.

Table 10: Potential Impact of Missed Compliance

Utility	3-Year, CPP Emissions Allowance[39] (Metric Tons)	1.5% CPP Exceedance (Metric Tons)	1.5% Exceedance in Gas Sales (Therms)	Potential 2025 Fine @ Avg. CCI $/Metric Ton		Comparator: *2020 Operating Expenses*
AVA	2,028,960	30,434	5,636,000	$3,286,915		$96,658,000
CNG	2,145,309	32,180	5,959,192	$3,475,401		$48,930,000
NWN	16,615,303	249,230	46,153,619	$26,916,791		$402,484,000

With this in mind it is worth noting that persuasive arguments could be made that avoidable fines should not be paid by ratepayers.

The resulting uncertainty and possible financial risk highlight the need for robust monitoring, tracking, and reporting of both the efficacy of compliance strategies and market developments informing the selected compliance strategy. For reference purposes, each gas utility put forth their preferred strategy to achieve compliance by 2025 in this docket. The table below summarizes each utility's preferred 2022 through 2024 compliance strategy by element.

Table 11: Total Aggregate Reduction for 2022 through 2024 Period by Strategy

Utility	Aggregate 3-Year, CPP Emissions Reduction Goal *(Tons Reduced From Baseline)*		Additional EE/DR			RNG			CCI		Other			Total
			%	Dth	Tons	%	Dth	Tons	%	Tons*	%	Dth	Tons	Tons*1
AVA	188,282		7%	251,710	13,985	12%	-	23,095	81%	153,521	2%	75,148	3,973	190,601
CNG	249,567		14%	164,500	34,801	9%	403,350	21,402	77%	193,364				249,567
NWN	759,354		14%	2,007,951	106,542	51%	3,657,331	386,279	35%	264,718				757,539
	Totals			2,424,160			4,060,681			611,603		75,148		

** - ton equivalent for CCIs*

**1 - Modeled totals may not equal the Aggregate 3-Year CPP Emission Reduction Goal.*

The emissions levels set for the first compliance window (2022 through 2024) require that the gas utilities accomplish what appear to be achievable emission reductions with all three companies making use of allowed CCIs to aid overall company compliance. Perhaps the two biggest near-term challenges will be their reliance on RNG and building the compliance-related infrastructure for the 2025-2027 time period. To this end, NWN is actively pursuing RNG projects, and both Cascade and Avista have indicated in their most recent IRPs that RNG is a resource they have begun pursuing and that the PUC should expect to see it in their forthcoming IRPs.

By comparison, the GHG emission reducing resources required by the end of the second compliance window (2025 through 2027) are substantially larger than the first compliance window.

As shown in Table 12, collectively Oregon's gas utilities will need by 2027:

[39] Calculated using the numbers in OAR 340-271-9000. Table 4.

- 61.6 million Dekatherms of additional avoided demand with energy efficiency and demand reduction,
- 30 million Dekatherms of biogenic RNG,
- 1.7 million CCI credits,
- 920,000 Dekatherms of hydrogen, and
- 300,000 Dekatherms of avoided demand with other programs.

Table 12: Total Aggregate Reduction for 2022 through 2027 by Strategy

Utility	Aggregate 6-Year, CPP Emissions Reduction Goal	Additional EE/DR			RNG			Hydrogen			CCI		Other			Total
	(Tons Reduced From Baseline)	%	Dth	Tons	%	Dth	Tons	%	Dth	Tons	%	Tons*	%	Dth	Tons	Tons
AVA	630,153	7%	835,252	44,156	19%	2,780,979	119,785	8%	919,771	48,624	64%	410,229	3%	377,496	19,956	642,751
CNG	812,939	12%	1,816,124	96,364	43%	6,600,449	350,220	0%	-	-	45%	366,356	0%			812,939
NWN	3,537,123	20%	79,987,893	701,017	38%	25,264,527	1,340,536	0%	-	-	42%	1,483,624	0%			3,525,177
	Totals		82,639,268			34,645,955			919,771			2,260,210		302,348		
	Additional from first compliance window		61,639,346			30,148,407			919,771			1,648,606				

With less than six years before the first GHG reduction requirements in the CPP must be met, the gas utilities and markets will need to move at an unprecedented scale and speed. To manage and mitigate ratepayer risk, the PUC will need to regularly assess and validate performance of the utilities' preferred compliance strategies so course corrections can be made quickly, if necessary.

While each utility is unique and must be afforded the space to choose how they meet CPP compliance, they all function within the same set of market and regulatory constraints. Staff found the divergent forecasts of technology progress and the market availability of alternatives in the utilities' compliance strategies somewhat perplexing and unhelpful overall given the market they share. This highlights the uncertainty that remains around utility compliance across three different companies with a rapidly evolving set of markets and technology. Given the time constraints of the CPP goals, Staff believes the IRP process of each utility individually assessing technology progress and forecasting alternative fuel availability may be inefficient and lead to counterproductive outcomes in planning to meet compliance needs.

4.5.1 Actions

To inform risk assessments, Staff believes the following tools would help the PUC and stakeholders monitor, track, and incorporate market trends and forecasts for alternative gas availability and costs.

Planning

- Host an annual presentation to Commissioners on CPP compliance, comparing forecasted versus actual emission reductions and CPP costs.

Rates

- Submit through the Purchased Gas Adjustment process, or other annual docket, an annual report on full CPP compliance costs.
- Explore linking the amortization of CPP compliance costs from deferrals to actual CPP performance. Should gas companies selected CPP compliance activities fall short of meeting a DEQ, 3-year CPP compliance demonstration window, PUC Staff should investigate the extent to which deferred CPP costs should be amortized in subsequent years.

4.6 Actively Incentivize or Facilitate GHG Emission Reduction Pathways

Gas utilities need to develop and deploy strategies to meet CPP compliance obligations. During the Fact Finding, stakeholders explored how the PUC processes could facilitate the deployment of nascent technologies to decarbonize fuels and improve energy efficiency, as well as exercising new policy direction to promote fuel switching to reduce natural gas use.

The PUC has existing tools at its disposal, like SB 844, which allows gas companies to receive financial incentives for GHG emission reductions activity costs that are outside their normal course of business. Other tools may need to be revisited to explore the boundaries of what is possible within them (*e.g.*, ETO energy efficiency programs).

Incentives and Pilots

The base case long-term compliance strategies of the utilities all rely on growing amounts of RNG, green hydrogen, synthetic biofuels, and new energy efficient gas equipment technologies. By doing so, these strategies mitigate the need for electrification and placing any limits on new customer hook-ups. However, the potential variance around the future cost, availability, and market adoption of new technology makes the efficacy of these compliance strategies uncertain.

Further, while every pathway – from renewable hydrogen to aggressive electrification – most likely requires piloting to achieve broad implementation, Staff cautions that any gas companies' pilots should avoid excessive financial risks to customers. Pilot projects – like Energy Trust's proposed Dual Fuel[40] pilot – require significant coordination across organizations but stand to benefit ratepayers from understanding the extent to which this strategy achieves cost-effective emission reductions.

[40] *See* Energy Trust 2023 Budget and 2023-2024 Action Plan, Dec. 16, 2022, mentioned in each utility action plan.

STAKEHOLDER INSIGHTS

PILOTS

H2 / CCSU pilots may be beneficial, but program costs should be fairly allocated between shareholders and rate payers – traditional ratemaking might not work – *AWEC*

Ratepayers should not pay for alternative gas pilots at the expense of leveraging proven technologies and innovation should be funded by investors, not ratepayers – *JC-CS et al.*

Pilots should not be used for gas heat pumps as doing so interferes with Energy Trust's analysis on potential, and NEEA is already doing work in this space – *CUB*

Gas utilities should fund ETO to conduct conservation potential study on how CPP emission reductions and costs of RNG affect cost effectiveness of energy efficiency; this would help inform whether NG heat pump pilots are appropriate at this time – *CUB*

Supports ETO training on gas and electric heat pumps – *NWN and CNG*

Public funds should not be used to promote gas heat pumps because of their relatively low commercial and technology readiness as compared to electric heat pumps - *CUB, JC - EC et al., JC - CS et al., JC - MCAT, NRDC, TNC*

STAKEHOLDER INSIGHTS

ROLE OF INCENTIVES

Eliminate subsidies or incentives that promote or support gas system expansion, gas heat pumps, or RNG - *JC - EC et al., JC - CS et al., Multnomah County, Zero Coalition and JC – Mayoral*

The role of PUC is to ensure compliance and protect customers, not provide incentives for utilities to comply with the law – *NWEC*

PUC should encourage gas companies to innovate to reduce emissions - *NWN, CNG, AWEC, and JC - NWGA et al.*

Support for innovation should only be for hard to decarbonize end uses *JC - CS et al.*

PUC has long history of not supporting customer-funded R&D, there is sufficient federal and private support for Green H2, and PUC should focus on directing utilities to do things they would not otherwise do, like electrification and limiting new hook ups – *NWEC*

Utilities drive market trends and the Commission should strongly encourage near-term investments in promising new decarbonization strategies - NWN

4.6.1 Actions

Staff finds the PUC's existing tools provide the flexibility to explore a range of CPP compliance strategies. Feedback from these projects – and from DEQ annual compliance reporting – will help inform planning and prudency determinations in the future.

The PUC remains open to new investments and pilots under SB 98 and SB 844. They provide space for experimentation and evaluation and, when paired with market research and regular evaluation, support the PUC's heighten awareness of and responsiveness to CPP compliance investments.

Planning

- Continue the use of SB 844 to as a tool for exploring emerging technologies that could be important to reaching 2050 targets, but that currently do not demonstrate cost-effectiveness because of their early-stage commercial or technological readiness.

Programs[41]

- Request the gas and electric utilities explore studying – between themselves and with organizations such as Energy Trust – the development of joint pilots where the coordination between the two utilities might result in better outcomes for customers (*e.g.*, for such things as Green Hydrogen production and Demand Side Management options such as dual-fuel heat pump deployment) and present their findings to the PUC before January 2025.

[41] The Draft Report previously included the following recommendation, "Direct Energy Trust to expand training vendors on heat pump technology through education and pilots and increase the marketing of heat pump technology on its website." Based on stakeholder comments and further research, this recommendation was deemed unnecessary.

4.7 Roadmap Summarizing Staff's Near-Term Recommendations

The regulatory actions identified through our Fact Finding effort may not reflect all the potential actions raised by stakeholders and available to the PUC. Stakeholders responded to Staff's list of near-term actions in the Draft Report and provided guidance about additional tools that are available to the PUC and regulatory tools they had hoped to have discussed as part of this docket.[42]

These included: a more explicit conversation about phasing out gas LEAs; more attention to Energy Trust policies to identify and remove barriers to gas and bulk fuel customers choosing to transition to more-efficient electric options; expanding low-income weatherization programs to allow for funds to be used for low-income electrification options and/or create a pilot program to encourage equitable electrification for LMI households; continuing and expanding current efforts to ensure robust low-income ratepayer protections; and exploring the value of pruning to strategically resize the gas system where it is aging, inefficient, or requiring significant and expensive upgrades.

CUB, in particular stated the docket should have included investigation of: "no pipes solutions; line extension reform; useful lives and depreciation curves; discouraging incentives to switch from electricity to gas; reallocating investment risk; and fuel switching."

These additional regulatory tools and issues are reflected above to help inform future investigations and to inform the PUC's work in relevant dockets. In particular, in

- IRPs, where Staff asks whether the company's resource strategy least-cost, least-risk in light of the obligations of the CPP;
- General Rate Cases, where Staff asks whether rates reflect prudent and reasonable costs, balance of risks and incentives, proportional allocation of costs and benefits of CPP compliance; and
- PUC oversight of Energy Trust of Oregon to ensure energy efficiency is fully leveraged as a significant part of every utility's emission reduction pathway.

STAKEHOLDER INSIGHTS

NEAR TERM ACTIONS

Phase out gas Line Extension Allowances - *JC - CS et al.*

Update Energy Trust policies to facilitate access to electric options – *JC-CS et al.*

Expand low-income weatherization programs to include electrification options - *JC - CS et al.*

Explore gas system pruning to strategically resize the gas system where it is aging, inefficient, or requiring significant and expensive upgrades - *JC - CS et al.*

Differentiate ratepayer bill impacts by LMI – *JC – CS et al.*

[42] Please see Section 2.4 and Appendix E for more details

Given this and the PUC's decisions and activities undertaken during the last half of 2022 (*e.g.,* UG 435 Order No. 22-388, LC 76 acknowledgement, and the Energy Trust 2023 budget) Staff's list of NGFF recommendations has evolved since the Draft Report was published in April 2022. The revised list is as follows.

Table 13: Roadmap of Near-Term Actions

Section 5 Analysis	**Recommendation**	**Regulatory Tool**		
		Planning	Programs	Ratemaking
Protecting Customers	Estimated Ratepayer Bill impact	X		
	Direct ETO to target programs to LI and EJ		X	
	Target IRA Incentives		X	
	EE programs to include transport		X	
	Assess CPP compliance risk in distribution system investments	X		X
	Explore rate impacts of accelerated depreciation in rate cases			X
	Transport customer cost of compliance in rate cases			X
Access and Info	Quarterly stakeholder Communications in UM 2178	X		
	RFA docket engagement through PUC AHD			X
Full Cost	Compliance costs into EE AC			X
	Develop marginal abatement cost curve	X		
	Utilities articulate electrification assumption in IRPs	X		
	Electrification info and data from DSP	X		
Decarbonization Planning & Cost-Recovery	Gas system maps with infrastructure age and depreciation information	X		
	IRPs include growth-related DSP investments details from Appendix F and provide analysis of demand-side options and non-pipe alternatives	X		
	Independent 3rd party analysis of key tech and market assumptions used utilities	X		
	CPP as an acknowledgeable item in IRPs	X		
	Exploring IRP guidance from UM 2178	X		
	Follow Order No. 22-388 guidance regarding customer growth and compliance costs	X		X
Monitoring, Tracking, and Reporting	Utilities host annual presentation to PUC on CPP compliance filings	X		
	Purchased Gas Adjustment includes full CPP compliance costs			X
	Explore linking CPP amortization to CPP performance			X
Incentivize GHG Reductions	Explore use of SB 844 for emerging technologies	X		
	Pilot or Joint pilots with electric utilities proposals by 2025			X

5 CONCLUSION

This investigation sought to establish an initial understanding of the impact of the CPP on the gas utilities and their customers and explore the regulatory tools available to achieve compliance while mitigating certain cost impacts. The timely modeling completed by each gas utility and the constructive engagement by dozens of stakeholders resulted in an initial analytic foundation from which to guide PUC activities, analysis, and decision making in both the near- and long- term.

Meeting the emissions targets in the CPP is the energy policy of the state. Collectively, Oregon's three gas utilities must find and secure approximately 1.2 million metric tons of GHG emission reductions by 2025. Further, the pressure for near-term emissions reductions increases greatly after 2025. By 2028, in less than six years, an additional 3.8 million metric tons of new GHG emission reductions must be secured. Solutions – be they supply oriented or demand reducing – must scale quickly in the near-term.

Modeling done by the gas utilities in this docket provided our first insights into the nature of the impacts of compliance with the CPP and existing barriers to assessing and mitigating energy decarbonization risk in planning more broadly. It is highly likely that most if not all CPP compliance strategies will come with increased costs and risks that must be monitored and tracked, and when appropriate, mitigated. If thoughtfully done, the transition to a decarbonized gas sector can create benefits and long-term cost savings for customers and the Oregon economy.

The issues identified by stakeholders and Staff and the suggested next steps are driven by the urgent need for action. Despite uncertainty around the efficacy and long-term cost trends of compliance tools, the pace of necessary emission reductions will likely require utilities and customers to assume increased levels of risk over the next ten years.

Feedback from both the utilities and other stakeholders throughout the process made it clear that this urgency is understood. Stakeholders agreed that regulatory tools should facilitate strategies that result in real reductions in GHG emissions and that they should do so in ways that seek to minimize costs and risks to protect customers. All stakeholders supported compliance strategies and associated regulatory tools that reduced gas use per customer. Staff believes that customers, especially low-income customers, are best protected with compliance strategies and regulatory tools that reduce compliance uncertainty at relatively low-cost in the near-term and maintain compliance flexibility.

Further strategy-specific regulatory tools that attempt to address uncertainty, costs, and risks associated with compliance also bring their own risks. As the utilities, stakeholders, and the PUC gain experience from implementation of tools and strategies for compliance in individual utility dockets over the next few years, it will also be important for Staff and/or the PUC to identify a future docket where a comprehensive dialogue can occur among all stakeholders around the collective efficacy of CPP compliance. A notable juncture to bring all stakeholders and utilities together for a group conversation on joint planning would be after 2023, when the first round of IRPs since the CPP adoption and HB 2021's passage are complete.

This report captures some of the regulatory tools that hold gas utilities accountable as they plan and pursue least-cost, least-risk options to reduce their GHG emissions by: increasing transparency, maintaining optionality, and enhancing engagement. Staff intends to apply these principles as it considers which tools to bring forward as it develops recommendations in IRPs and rate cases.

Appendices

6 APPENDIX A: SCENARIO DESCRIPTIONS

6.1 MODELING DIRECTION: DELIVERABLES, SENSITIVITIES, AND ALTERNATIVE SCENARIOS

A key component of the PUC's Natural Gas Fact Finding (NGFF, Fact Finding, or UM 2178) was the development of Compliance Models to establish a range of potential costs associated with achieving the goals of DEQ's Climate Protection Program (CPP). The development of this data served as the foundation for identifying and assessing which regulatory tools may be needed in the future by the utilities and the PUC to support the CPP and natural gas utility decarbonization.

The launch and completion of the utility Fact Finding modeling occurred before two key events: each utility's Integrated Resource Plan (IRP) and the finalization of DEQ's CPP in rules. Because of this, the utilities lacked the latest IRP information, the time and resources to run full IRP models, and complete certainty of important operational details. Thus, Staff informed all Fact Finding participants that while the accuracy of any modeling cost estimates would be limited, the information would be valuable going into 2022. In that year, CPP compliance would begin, and each utility would begin development – and for NW Natural, completion – of their next IRPs. The information from the Fact Finding would serve to foreshadow utility compliance strategy and the direction and magnitude of compliance potential costs, in addition to starting an important dialogue among all stakeholders about the application and efficacy of regulatory tools needed to achieve the state's GHG reduction goals.

Prior to any utility modeling, Staff created a summary of key utility data that could help stakeholders with their analysis of utility compliance modeling. Titled "Foundational Data," these documents comprise two Excel workbooks using data from multiple public sources and can be found online at this link.

The utilities were asked to deliver two large sets of deliverables in a very short time. The first was a presentation and underlying data to their initial NGFF model runs with selected sensitivities. The second was a presentation using alternative scenarios, which were shaped by participant input in the form of written and verbal comments. The table below captures the major milestones in the NGFF compliance modeling activities, with links to key documents.

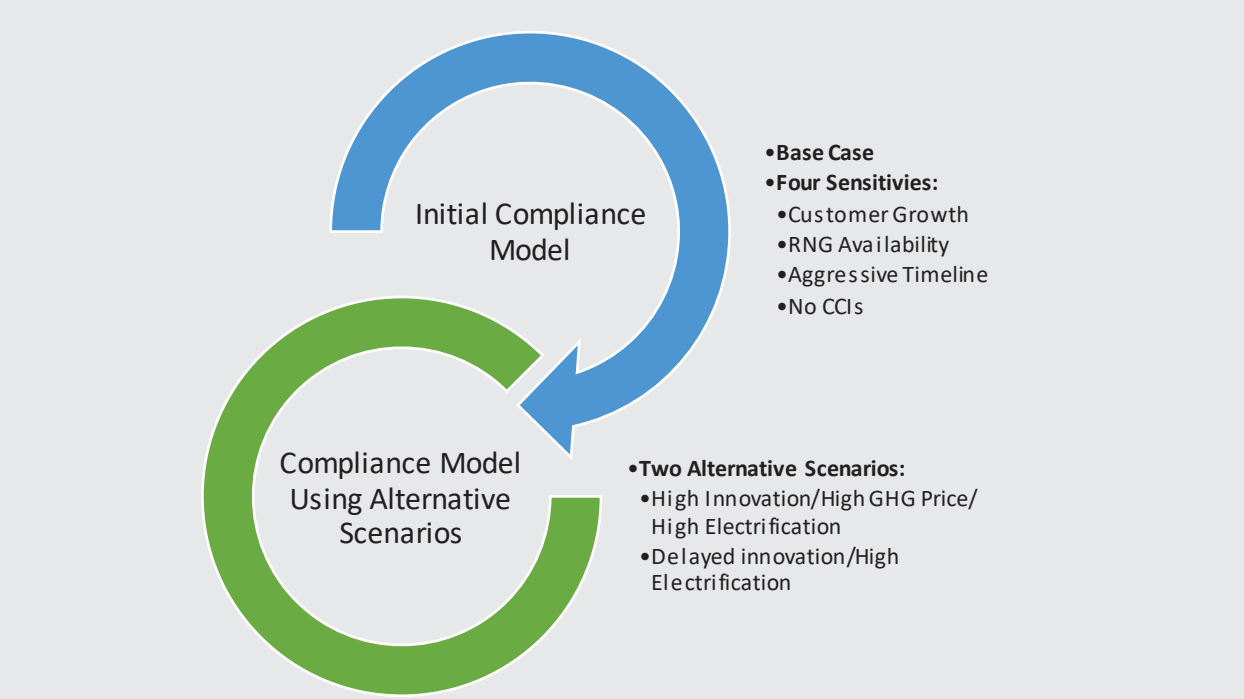
Table A1: Major Milestones in NGFF Modeling Activities

Date	Deliverable/Item	Additional information
July 8, 2021	Staff's initial compliance modeling proposal	Initial expectations for data to be used (inputs) by utilities in their analysis, the key deliverables to be shared (outputs). Modeling sensitivity selection occurs after input from stakeholders.
July 26 -30, 2021	Stakeholder comments on modeling proposal and suggestions for potential sensitivities	*See docket for more information.*
Aug. 4, 2021	Modeling sensitivities to inform initial model	Four sensitives selected by Staff after stakeholder input.

Date	Deliverable/Item	Additional information
Sept. 7-24, 2021	Utilities' initial modeling results	Initial modeling results provided on Sept. 7 with some supplemental and revised filings through Sept. 24. *See docket for more information.*
Sept. 24-27, 2021	Stakeholder comments on utility modeling results	Alliance of Western Energy Consumers Sierra Club Joint Parties, including Climate Solutions Citizens' Utility Board NW Natural Wendy Woods RNG Coalition Metro Climate Action #1 & #2
Oct. 1, 2021	Staff's alternative modeling scenarios	Alternative scenarios differ from sensitivities in that the scenarios alter the underlying assumptions, and in some cases, the data used by the initial model. Two alternate scenarios were selected based on participant feedback in NGFF workshops and from comments.
Nov. 17, 2021	Utilities' alternative modeling scenario runs	Avista's presentation of results CNG's presentation of results NW Natural's presentation of results

Given the timing and short turnaround time for the initial model runs, the natural gas companies were asked to use past IRP data, the most current version of CPP rules, and to model a base case of CPP compliance strategies they envisioned worked best for their company. They were also asked to consider a set of sensitivities, which were intended to stress test the company's proposed pathway. The selected alternative modeling scenarios attempted to show the impact of CPP compliance in two possible futures, combining multiple sensitivities within the initial model: one in which there was aggressive electrification of gas loads, and one in which efforts were directed to accelerate innovation in decarbonizing gas. Figure A1 provides a graphic representation of the scenarios and sensitivities the utilities modeled.

Figure A1: Scenarios and Sensitivities for NGFF Utility Modeling



6.1.1 Key Deliverables from initial modeling

Each utility delivered a presentation and underlying data as part of the model runs. Specified outputs to be shared included the following:

1. Forecast of emissions (weather adjusted):
    a. Graphic of million metric tons CO2e per year
        i. Stacked Area chart
        ii. Estimates of avoided emissions by compliance strategy and technology
    b. Supporting table capturing underlying data used in graphic by year
    c. Annual emissions reduction by compliance strategy, technology, and portfolio of technologies
    d. Annual emissions reduction in metric tons by technology by year
    e. Annual emissions above or below annual DEQ CPP threshold

2. Data supporting the development of emissions forecasts, including but not limited to:
    a. Load forecast and growth assumptions
    b. Use per customer estimates
    c. Compliance strategy assumptions
        i. Demand, supply, and capture assumptions
        ii. Sector/customer class reduction assumptions
        iii. Technology assumptions
            1. Cost trajectory curves over time for each technology
            2. Tons of emissions avoided per therm for each technology
            3. Variable costs per therm for each technology
    d. Any major distribution or transmission system upgrades or changes

e. In addition to the above data, all model inputs, outputs, and workpapers provided in electronic format with all references and formulae intact.

3. Description of approach and/or assumptions, including but not limited to:
   a. Values and terms selected for DEQ key assumptions
   b. Model methodology
   c. Description of weather pattern forecasts impacting load forecast
   d. Avoided costs assumptions, such as peak day usage and savings ratios

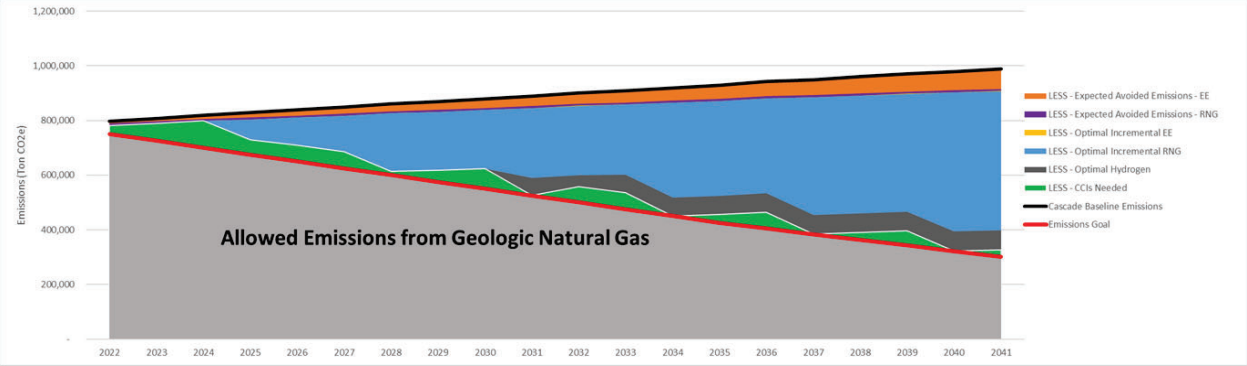
4. Estimated Net Present Revenue Requirement of Compliance Model and Comparison Across Selected Sensitivities:
   a. Twenty year time horizon minimum
   b. Annual and total Revenue Requirement difference between Compliance Model and most recent IRP's preferred portfolio
   c. Annual and total Revenue Requirement difference between Compliance Model and selected sensitivities.

6.1.2 Results of Base Case Compliance Strategies

The base case strategies for CPP compliance varied across utilities. Figures A2-A4 below summarize the compliance strategies each utility presented in UM 2178 workshops.

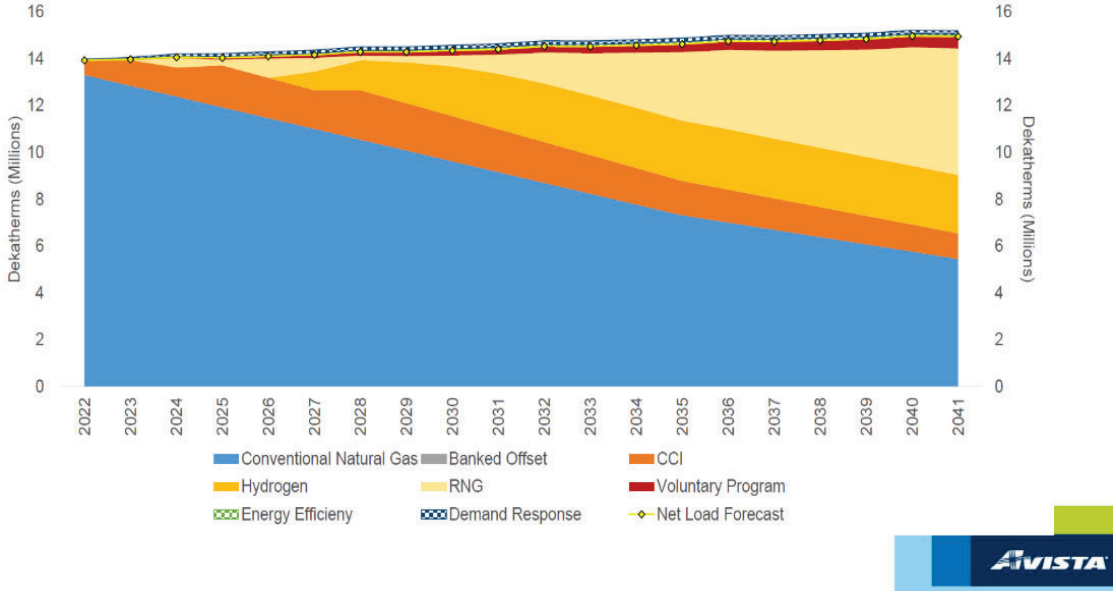
Cascade relied on CCIs in the near term and then heavily on incremental RNG (blue sliver in Figure A2) beyond what it planned for with SB 98 RNG (purple sliver in Figure A2).

Figure A2: Cascade CPP Base Case Compliance Strategies



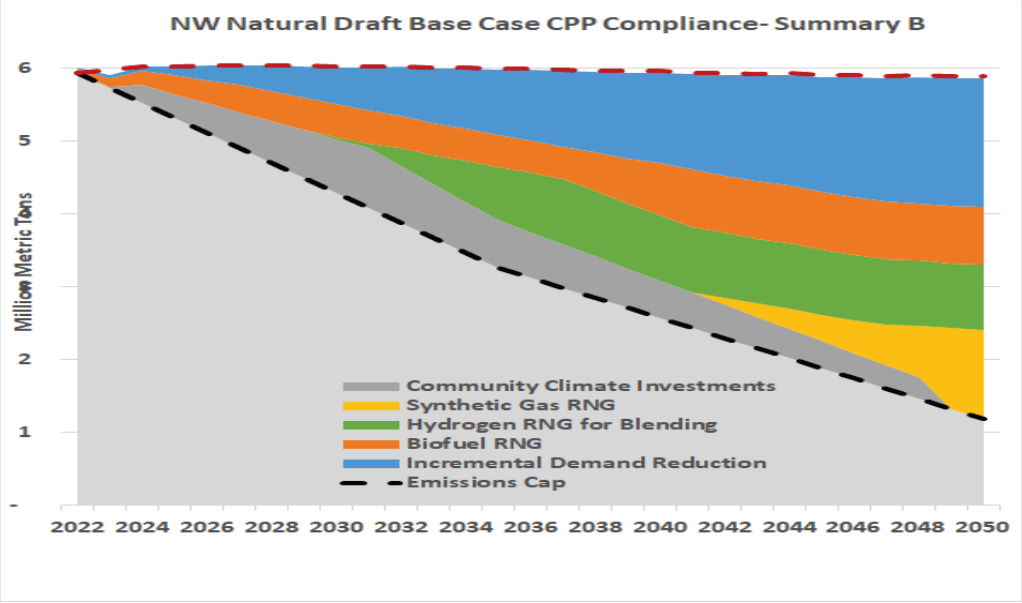
Avista also relied on CCIs in the near term and biofuel RNG throughout, but brings in hydrogen in 2026.

Figure A3: Avista Base Case CPP Compliance Strategies



NW Natural increasingly relies on demand reduction/EE over the course of the compliance timeframe. Its use of biofuel RNG and CCIs start in the near term and play a moderate role throughout, with CCI's decreasing and RNG increasing. By 2031 it introduces hydrogen and by about 2040, begins to envision the inclusion of synthetic gas RNG.

Figure A4: NW Natural Base Case CPP Compliance Strategies



6.1.3 Sensitivities

Below is a description of each of the four sensitivities to accompany the initial model run's base case. Each sensitivity was run in isolation from the other. A comparison of the results for each sensitivity are included in Figures A5-A8.

6.1.3.1 Customer Decline

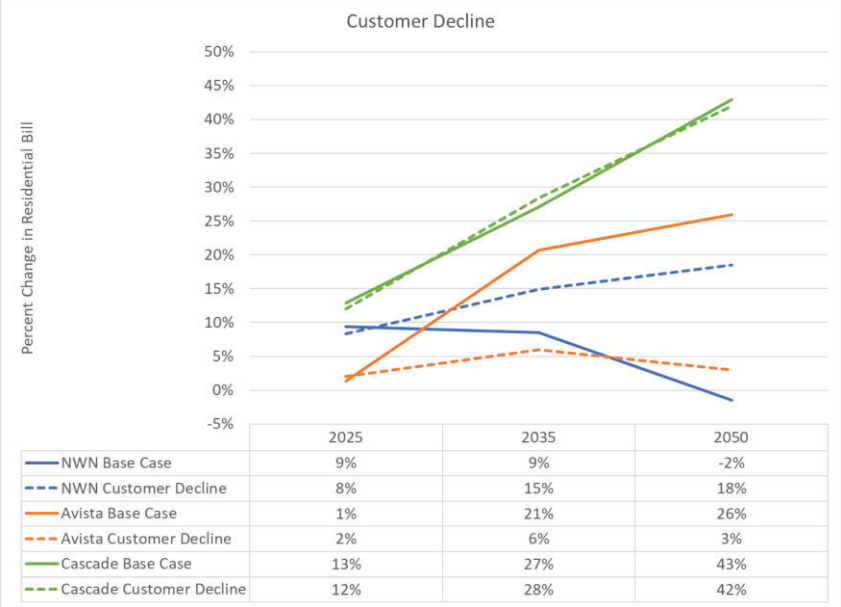
Issue: How might policies limiting customer growth and associated GHG emissions inform regulatory tools to consider?

Approach: Model sensitivities that consider zero and negative customer growth.

Sensitivity: Current IRP forecasted load growth through 2025; no new customers beginning from 2025 through 2030; -0.75 percent customer growth beginning in 2031 through the end of model's time horizon.

Results: NWN modeling showed customer declines result in increased compliance costs above those of its base case as the years progressed. Avista compliance costs decreased with declining customers and Cascade saw costs remain almost identical to its base case.[43]

Figure A5: Customer Decline Sensitivity Comparison



	2025	2035	2050
NWN Base Case	9%	9%	-2%
NWN Customer Decline	8%	15%	18%
Avista Base Case	1%	21%	26%
Avista Customer Decline	2%	6%	3%
Cascade Base Case	13%	27%	43%
Cascade Customer Decline	12%	28%	42%

6.1.3.2 RNG Availability

Issue: Uncertainty about availability of RNG.

[43] Avista noted that its modeling did not accurately reflect the increase in cost per customer that would result from customer declines because of the need to spread fixed costs over fewer customers. This omission, it says, makes all its electrification and ratepayer decline scenario bill impacts lower than they should be.

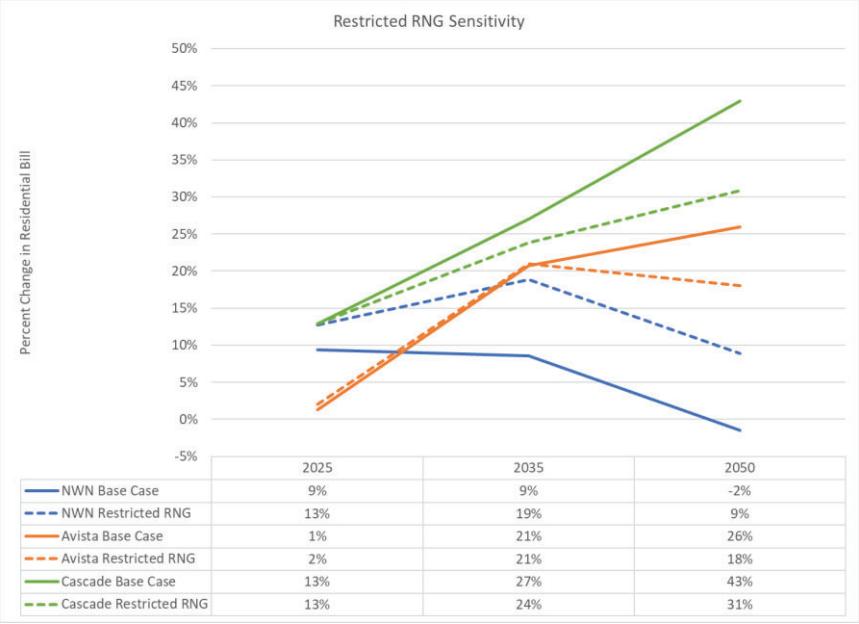
Approach: Apply constraints on assumptions about the availability of RNG to meet emission reduction goals.

Sensitivity: Limit RNG availability to the annual percentages set by SB 98 and found in ORS 757.396(1).

(a) In each of the calendar years 2020 through 2024, five percent may be renewable natural gas;
(b) In each of the calendar years 2025 through 2029, 10 percent may be renewable natural gas;
(c) In each of the calendar years 2030 through 2034, 15 percent may be renewable natural gas;
(d) In each of the calendar years 2035 through 2039, 20 percent may be renewable natural gas;
(e) In each of the calendar years 2040 through 2044, 25 percent may be renewable natural gas; and
(f) In each of the calendar years 2045 through 2050, 30 percent may be renewable natural gas.

Results: Restricting RNG had mixed results – NWN modeled increased RNG prices with the restriction, resulting in higher costs compared to base case. Avista and Cascade reduced how much RNG was used for compliance, which reduced the overall cost of compliance compared to their base case scenarios. This generally increased cost of compliance for NWN, but Cascade and Avista saw decreased compliance costs in the later years of the model run when compared to their base cases.

Figure A6: Restricted RNG Sensitivity Comparison



	2025	2035	2050
NWN Base Case	9%	9%	-2%
NWN Restricted RNG	13%	19%	9%
Avista Base Case	1%	21%	26%
Avista Restricted RNG	2%	21%	18%
Cascade Base Case	13%	27%	43%
Cascade Restricted RNG	13%	24%	31%

6.1.3.3 More Aggressive Timeline on Climate Policy

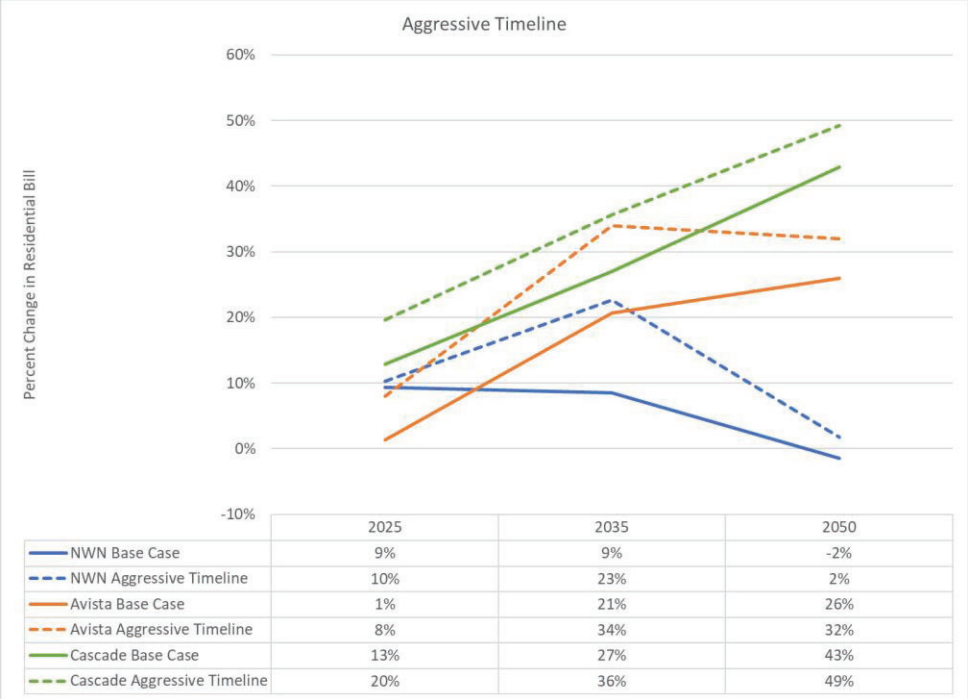
Issue: The Governor's Executive Order set state emission reduction targets of at least 45 percent below 1990 levels by 2035 and at least 80 percent below 1990 levels by 2050. The DEQ Climate Protection Program is poised to make progress towards these state emission reduction targets. However, there is the potential for future policy to have more aggressive targets.

Approach: Using the same target reduction emissions currently contemplated by DEQ for 2035 and 2050, advance the dates to align with the date bookends (2030 and 2040) of the recently passed Oregon legislation for electric utilities (HB 2021).

Sensitivity: CPP targets of 45 percent below baseline by 2030, 80 percent below baseline by 2040.

Results: NWN costs increased in the middle years of the model run but the difference between this sensitivity and the base case shrank as they approached 2050. Avista and Cascade's aggressive timeline model runs showed compliance costs consistently higher than in their base cases for all customer types.

Figure A7: Aggressive Timeline Sensitivity Comparison



	2025	2035	2050
NWN Base Case	9%	9%	-2%
NWN Aggressive Timeline	10%	23%	2%
Avista Base Case	1%	21%	26%
Avista Aggressive Timeline	8%	34%	32%
Cascade Base Case	13%	27%	43%
Cascade Aggressive Timeline	20%	36%	49%

6.1.3.4 No CCI

Issue: Community Climate Investments (CCI) are a CPP compliance instrument. However, it is not currently clear to the PUC how the emissions associated with these projects will be quantified and verified. PUC Staff would like to understand the role CCIs play in accomplishing compliance with emission reductions and what emission reduction options become more viable if they are not part of a solution set.

Approach: Remove the availability of CCIs.

Results: All companies showed that the inability to use CCI's would result in higher compliance cost than in their base cases in the early years. But by 2050 the three utilities' modeling runs arrived at different conclusions with NWN's annual compliance costs continuing to outpace compliance costs in its base case, while Avista's cost differential was shrinking and Cascade's annual compliance costs were the same as in its base case.

Figure A8: No CCI Sensitivity Comparison

	2025	2035	2050
NWN Base Case	9%	9%	-2%
NWN No CCIs	11%	13%	3%
Avista Base Case	1%	21%	26%
Avista No CCIs	8%	25%	29%
Cascade Base Case	13%	27%	43%
Cascade No CCIs	16%	28%	43%

6.1.4 Alternative Scenarios

The alternative scenarios were run after the initial compliance models were completed and shared. They were greatly shaped by participant feedback. They combined multiple sensitivities from the previous model run, in some cases with new data. These two scenarios were designed to characterize possible futures that explored potential impacts, suggesting different policy and planning approaches.

6.1.4.1 Alt. Scenario 1: Accelerated Innovation / Electrification / High Social Cost of Greenhouse Gas

Approach:

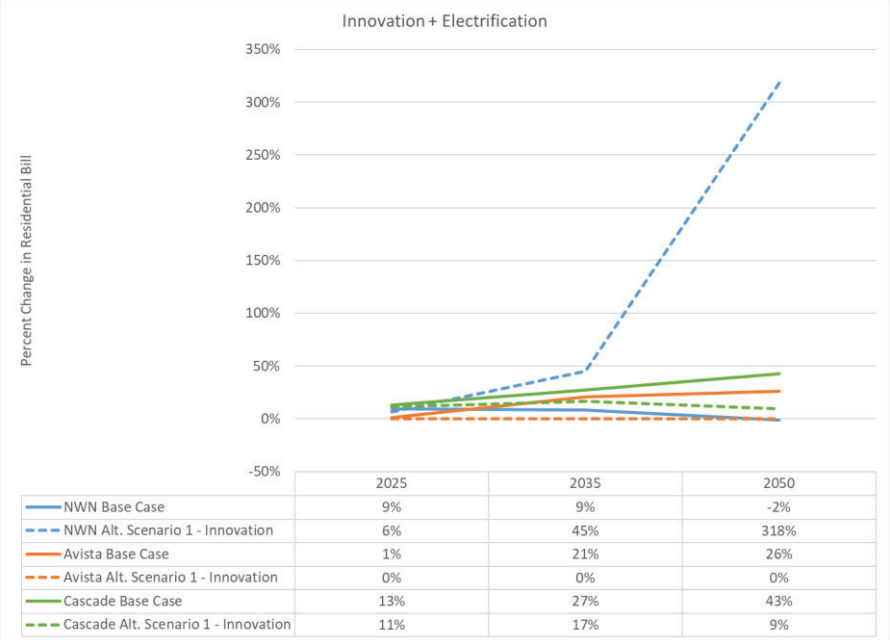
- **Accelerated Innovation:** Assume a 30 percent six-year production tax credit for the production of green hydrogen and syngas for which construction begins before 2026.[44] It is anticipated that projects may be outside the ordinary course of business and would result in near-term and aggressive emission reductions.
- **Higher Cost of GHG**: Assume updates to the social cost of carbon. Beginning in 2026, adjust the CCI price to align with the Social Cost of Carbon's 95th percentile with a three percent discount.[45] For example, starting in 2026 use the starting value of $173.

[44] *See* page 49 of the Department of the Treasury, General Explanations of the Administration's Fiscal Year 2022 Revenue Proposals https://home.treasury.gov/system/files/131/General-Explanations-FY2022.pdf.
[45] *See* Social Cost of Carbon table A-1 in Appendix – Annual SC-CO2, SC-CH4, and SC-N2O Values, in 2020-2050. Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide – Interim Estimates under Executive Order 13990. Interagency Working Group on Social Cost of Greenhouse Gases, United States Government. https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf.

- **Electrification:**
  - Fraction of new buildings (residential and commercial) using gas goes from its present share to zero in 2030 and stays zero thereafter.
  - Existing buildings converting to electricity goes from its present share to 90 percent in 2050.
  - Light industry converts to 90 percent electricity by 2050.

Results: Cascade's model resulted in ratepayer bill impacts that were lower than in their base case.[46] Avista's modeling summary showed zero change in ratepayer bill impacts, but the workbooks showed negative ratepayer bill impacts for all customers except transport, and then compliance cost increases similar to those found in their base case. NWN's ratepayer bill impacts for the scenario increased significantly due to high electrification-related customer declines, which resulted in costs not tied to energy use being spread over many fewer customers (a 318 percent increase in non-energy charges in 2050). There was no increase in hydrogen usage on NWN's or Avista's system because the high electrification rates reduced or eliminated the need for fuel 'innovation.' Hydrogen usage was significantly decreased as a solution for Cascade when compared to its base case. For Avista, this scenario saw its transport customers pay an increasing share of the utility's compliance costs as the utility's retail customer count declined.

Figure A9: High Innovation + Electrification + High SCC Scenario Comparison



	2025	2035	2050
NWN Base Case	9%	9%	-2%
NWN Alt. Scenario 1 - Innovation	6%	45%	318%
Avista Base Case	1%	21%	26%
Avista Alt. Scenario 1 - Innovation	0%	0%	0%
Cascade Base Case	13%	27%	43%
Cascade Alt. Scenario 1 - Innovation	11%	17%	9%

[46] CNG noted that differences in electrification modeling may have been due to differing interpretations of the guidance from Staff.

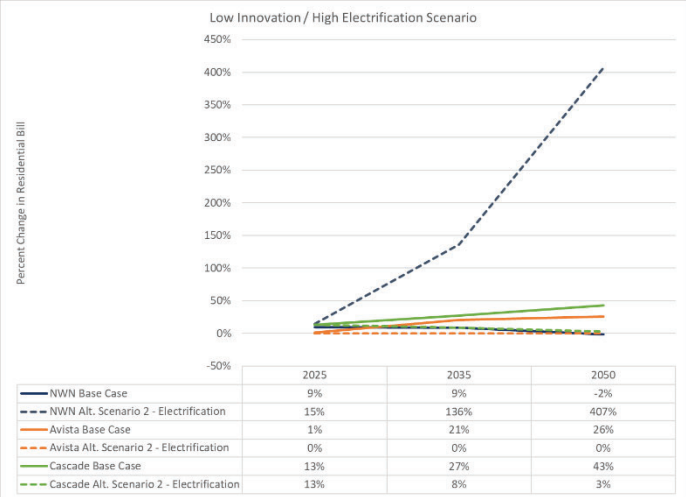
6.1.4.2 Alt. Scenario 2: Delayed Innovation / Accelerated Electrification

Approach:

- **Delayed Innovation:** Use a slower energy efficiency technology adoption curve. Gas heat pump water heaters come to market, but there are no gas heat pumps until after 2030 and they assume a traditional s-curve adoption pattern.[47]
- **Supply Competition:** RNG availability is limited to the percentage of the national RNG resource equal to the company's throughput share of total gas use in the U.S., including power sector use. National RNG resource is ICF's Low Resource Potential for RNG in 2040, namely 1,660 trillion Btu (tBtu) of RNG produced annually for pipeline injection by 2040.[48]
- **Very Rapid Electrification:**
  - The fraction of new buildings (residential and commercial) using gas goes from its present share to zero in 2025 and stays zero thereafter.
  - Fraction of existing buildings converting to electricity goes from its present share to 90 percent by 2040.

Results: Like the Accelerated Innovation and Electrification w/High SCC Scenario, Cascade modeled ratepayer bill impacts that were lower than their base case. Avista's summary showed zero ratepayer bill impacts, but the workbooks showed negative impacts in 2025 and then similar increases to the base case by 2035. NWN modeled the most aggressive electrification assumptions, resulting in a scenario that showed a significant drop in customers on the system and a 405% increase in residential bills by 2050. NWN also showed a moderate amount of industrial EE around 2035 and the use of banked allowance credits collected before 2042 for CPP compliance in the 2040s.

Figure A10: Delayed Innovation/High Electrification Scenario Comparison



	2025	2035	2050
NWN Base Case	9%	9%	-2%
NWN Alt. Scenario 2 - Electrification	15%	136%	407%
Avista Base Case	1%	21%	26%
Avista Alt. Scenario 2 - Electrification	0%	0%	0%
Cascade Base Case	13%	27%	43%
Cascade Alt. Scenario 2 - Electrification	13%	8%	3%

[47] *See* Comments of the Oregon Citizens' Utility Board on Modeling and Alternative Scenarios. Filed September 24, 2021. https://edocs.puc.state.or.us/efdocs/HAH/um2178hah163235.pdf.

[48] *See* American Gas Foundation Study Prepared by ICF. Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment. December 2019. https://gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdf.

6.1.4.3 Modeling Parameters for Alternative Scenarios

Companies were instructed to use existing models and data to create the alterative scenarios with the following deliverables:

- Updated graphics and tables comparable in format to those submitted for the base case and associated sensitivities.
- To the extent possible and applicable, Staff asked that Avista and Cascade replicate the Scenario Comparison table created and shared by NW Natural, and that all companies use this format to include the alternative scenarios described above.
- **Data for Electrification:**
    - Where a load currently served by gas is not eliminated, but rather served by another resource, total annual MMBtu transferred to the alternative source must be identified for each year.
    - Staff will calculate estimated costs of the transferred load and associated emissions, taking into consideration the electrification cost elements proposed by stakeholders in comments.
- **Low and Moderate Income Customers**: Indicate the assumed or known percentage of low and moderate income residential customers.
- **Ratepayer Bill Impacts**: Report ratepayer bill impacts in terms of $/therm.

Table A2. Summary of Compliance Base Case, Sensitivities, and Scenarios Impacts

	Sensitivities/ Scenarios	Renewable Supply Penetration (% of Deliveries)			Biofuel RNG Penetration (% of Current Deliveries)			Renewable Supply Portfolio Cost (2020$/Dth)			Total Incremental Cost of CPP Program (Million 2020$/Year)[49]			Community Climate Investments (% of Emissions)			Annual Residential Bill Impact (% Impact of CPP)			Annual Industrial Sales Bill Impact (% Impact of CPP)		
		2025	2035	2050	2025	2035	2050	2025	2035	2050	2025	2035	2050	2025	2035	2050	2025	2035	2050	2025	2035	2050
Northwest Natural	Base Case	*4%*	*23%*	*72%*	*4%*	*8%*	*14%*	*$12.25*	*$11.85*	*$11.77*	*$142*	*$256*	*$242*	*6%*	*20%*	*0%*	*9%*	*9%*	*-2%*	*22%*	*35%*	*39%*
	Restricted RNG	4%	23%	72%	4%	9%	11%	$18.75	$18.26	$16.90	$142	$317	$324	6%	20%	0%	13%	19%	9%	30%	59%	68%
	Customer Decline	4%	17%	65%	4%	9%	15%	$12.25	$11.93	$11.59	**$118**	**$181**	**$186**	6%	20%	0%	8%	15%	18%	18%	27%	37%
	Aggressive Timeline	4%	47%	65%	4%	16%	20%	$12.25	$13.15	$11.74	$168	$493	$360	13%	20%	20%	10%	23%	2%	27%	73%	58%
	No CCIs	10%	36%	72%	10%	15%	18%	$12.25	$12.64	$12.89	$167	$313	$296	0%	0%	0%	11%	13%	3%	26%	45%	51%
	Fed RNG Support	4%	23%	72%	4%	8%	14%	$8.58	$8.76	$8.80	$142	$239	$160	6%	20%	0%	7%	4%	-9%	18%	26%	17%
	Vol Comm Support	4%	16%	48%	4%	8%	9%	$12.25	$11.85	$11.25	$124	$214	$160	2%	20%	20%	8%	6%	-6%	19%	30%	25%
	Alt. Scn. #1	4%	12%	23%	4%	6%	6%	$12.25	$12.13	$12.13	**$0**	**$0**	**$0**	0%	0%	0%	6%	45%	318%	Unknown		
	Alt. Scn. #2	4%	9%	14%	4%	5%	5%	$12.25	$12.25	$12.25	**$0**	**$6**	**$13**	0%	0%	0%	15%	136%	407%			
Avista	*Base Case*	*2%*	*40%*	*54%*	*2%*	*20%*	*34%*	*$12.23*	*$9.71*	*$8.95*	*$2*	*$19*	*$26*	*13%*	*17%*	*17%*	*1%*	*21%*	*26%*	*14%*	*60%*	*72%*
	Restricted RNG	2%	40%	49%	2%	20%	27%	$12.23	$9.69	$8.54	$2	$19	$24	13%	17%	17%	2%	21%	18%	16%	62%	54%
	Customer Decline	2%	35%	47%	2%	15%	27%	$12.23	$9.31	$8.64	$2	$13	$15	13%	17%	17%	2%	6%	3%	16%	52%	59%
	Aggressive Timeline	9%	59%	76%	9%	39%	54%	$12.23	$10.55	$9.40	$6	$38	$46	13%	17%	17%	8%	34%	32%	33%	99%	93%
	No CCIs	15%	50%	61%	15%	30%	41%	$12.23	$10.23	$9.22	$7	$28	$35	0%	0%	0%	8%	25%	29%	34%	72%	80%
	Alt. Scn. #1	0%	26%	32%	0%	0%	0%	$0.00	$7.08	$5.44	$0	$0	$0	7%	0%	0%	0%	0%	0%	0%	0%	0%
	Alt. Scn. #2	0%	28%	49%	0%	0%	0%	$0.00	$7.08	$5.44	$0	$0	$0	5%	0%	0%	0%	0%	0%	0%	0%	0%
Cascade	*Base Case*	*10%*	*26%*	*65%*	*10%*	*26%*	*57%*	*$5.86*	*$4.94*	*$3.01*	*$12*	*$25*	*$33*	*6%*	*8%*	*0%*	*13%*	*27%*	*43%*	*16%*	*32%*	*50%*
	Restricted RNG	10%	25%	54%	10%	25%	46%	$5.86	$4.91	$2.75	$12	$21	$20	6%	6%	0%	13%	24%	31%	16%	29%	37%
	Customer Decline	6%	17%	28%	6%	15%	27%	$5.86	$4.91	$3.05	$11	$27	$32	10%	9%	10%	12%	28%	42%	15%	34%	49%
	Aggressive Timeline	17%	43%	83%	17%	37%	75%	$5.86	$4.78	$2.97	$20	$37	$43	6%	6%	0%	20%	36%	49%	24%	42%	56%
	No CCIs	16%	35%	65%	16%	27%	57%	$5.86	$4.59	$2.91	$16	$26	$33	0%	0%	0%	16%	28%	43%	20%	33%	49%
	Alt. Scn. #1	11%	33%	45%	11%	33%	44%	$5.86	$4.81	$2.39	$13	$24	$12	6%	0%	0%	11%	17%	9%	14%	21%	12%
	Alt. Scn. #2	6%	8%	13%	2%	3%	5%	$11.76	$4.66	$1.70	$16	$9	$2	9%	9%	3%	13%	8%	3%	16%	11%	4%

[49] Red figures indicate that the cost of compliance to NW Natural is offset by assumed electrification, where the cost of this e lectrification needs to be assessed on the electric rather than gas grid

7 APPENDIX B: IRP GUIDANCE

Throughout the Fact Finding workshops and comments, Staff heard feedback from stakeholders about ways to leverage and improve upon the existing gas utility integrated resource planning process. Staff, with support from the Regulatory Assistance Project, attempted to capture and categorize this feedback in Table B1 to help inform future IRPs. This table serves as a reference and compendium for ideas received as part of UM 2178 and to be considered potentially in the future when the Commission embarks on revising IRP guidance.

TABLE B1: IRP-RELATED FEEDBACK

Category	Addition to IRP
Expand Public Access & Equity	Expand communications about IRP - basics, process and outcomes/implications, start to expand customer understanding of impacts of new policies (CPP)
	Utilities should record and post workshops on website
	Capture additional customer information, create a baseline of customer statistics (energy burden, participation in programs - e.g. EE and LI) by location (e.g. zip code)
Load Forecast – Improvements	Consider and reflect potential impacts of local policies to limit gas in new construction.
	Provide data on customer trend gas and electric usage assumed for space and water heating, (gas furnaces/electric heat pumps/gas domestic hot water heaters/heat pump water heaters) across service territory population, by county or zip code, # of customers and share of electric utility overlap (*recent history and current state*)
	Provide transparent assumptions and data about customer technology adoption and behavior, including end use fuel splits between electric and gas over time and justification for technology adoption assumptions (e.g. relying on technology adoption modeling? Does modeling approach assess/compare all customer options?) (*forward looking*)
	Identify transportation load - industry types/end uses and explore H2 potential for these customers. Characterize how this load is currently served to understand new liability for compliance – include seasonality and daily nature of emissions
	Conduct sensitivities to load forecast around customer adoption of emerging EE technologies
RNG	Quantify the near- and long-term geographic availability of RNG potential, updated regularly. Provide detailed discussion/description with supporting workpapers for assumptions used to model RNG resources and market. Develop Base/Low/High cases of resource costs. Base/accelerated/delayed cases for availability and base/low/high volumes. Essentially creating a resource potential assessment for RNG. Be explicit about total RNG resource potential and justify assumptions about what will be available to Oregon gas utilities.
	Provide Bundled vs unbundled RNG assumptions
	Discussion of RNG affiliate plans

H2	Provide detailed discussion/description with supporting workpapers for assumptions used to model H2 resources. Develop Base/Low/High cases of resource costs. Base/accelerated/delayed cases for availability and base/low/high volumes. Essentially creating a resource potential assessment for H2 designed around end uses that can feasibly use H2. Be explicit about total H2 resource potential and justify assumptions about what will be available to Oregon gas utilities. Assumptions should include whether sited with energy user or if transport from production to end user required and costs/risks of new pipeline delivery infrastructure or storage needed.
EE and Beneficial Electrification	Review cost effective EE potential
	Develop Beneficial Electrification assumptions in coordination with electric utility
System Mapping / Infrastructure	Include planned infrastructure costs identified as new customer vs. maintenance of existing system. Identify high priority projects and 5 year planned investments with non-pipeline alternatives considered.
	Identify areas of new development / system expansion - with as much granularity as possible
	Scenarios of load decline should include assessment of stranded asset risk
	Include current rate base depreciation assumptions, list of assets and amortization schedules
Scenarios	H2 and RNG delayed growth vs. base case assumptions
	CPP compliance requirements more stringent than current (as modeled in UM 2178 scenario)
	Decline in load starting in 2030, after 2025-2030 no growth (as modeled in UM 2178)
Transparency and Clarity	Provide input data and results in a clear and transparent manner. Including such things as units, methodologies, assumptions, sources, and application.
Emissions	All portfolios should be designed to meet CPP, include discussion around risk of noncompliance costs
Cost and Risks	Account for biogenic CO_2 from RNG

8 APPENDIX C: RMI BUILDING ELECTRIFICATION POLICY PRESSURES

This table is an excerpt from materials provided by the Rocky Mountain Institute to PUC Staff via email on November 2, 2022.

- It is an informal landscape scan of the future of gas proceedings across the country.
- - While RMI intends to keep it updated, it is a work in progress and not intended to be comprehensive or up-to-the-minute. Some states may have more details than others.
- - For the most accurate information, refer to the state PUC dockets, many of which are linked in the "proceedings" tab
- - If you have questions, corrections, or additions, please contact Sherri Billimoria (sbillimoria@rmi.org) or Abby Alter (aalter@rmi.org)

State	Docket #	Title/link	Key filings to date	State-wide energy strategies, plans, or studies	Any state commitments / indications around electrification?
California	R1807006	Order Instituting Rulemaking to Establish a Framework and Processes for Assessing the Affordability of Utility Service	Fourth Amended Scoping Memo and Ruling from 9.15.21		SB 1477 (2018) funded and required CPUC to develop BUILD and TECH programs to reduce GHG from buildings AB 3232 (2018) required CEC to release an assessment of "the feasibility of reducing [GHG] emissions of California's buildings 40 percent below 1990 levels by 2030" link
	R1901011	Order Instituting Rulemaking Regarding Building Decarbonization			
	R2001007	Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning	10/14/21 Amended scoping memo outlines tracks 2a, 2b, and 2c scope and timeline. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M415/K275/415275138.PDF		
	R1202008	Order Instituting Rulemaking To Adopt Biomethane Standards And Requirements, Pipeline Open Access Rules, And Related Enforcement Provisions.	Staff published proposal.		
	CEC 21-IEPR-05	Natural Gas Outlook and Assessments -- IEPR (Integrated Energy Policy Report)			

Colorado	21M-0395G	Commission Review of the Regulation of Gas Utilities	Opening order C21-0516 (lists of questions for comment periods, plus procedural/leg background)	Colorado Greenhouse Gas Pollution Reduction Roadmap (Jan. 2021)	Roadmap shows significant electrification is needed AQCC says building reductions will be 100%
	21R-0449G	Proposed Amendments to the Commission's Rules Regulating Gas Utilities, 4 Code of Colorado Regulations 723-4, Relating to Gas Utility Planning and Implementing SB 21-264 Regarding Clean Heat Plans and HB 21-1238 Regarding Demand Side Management	NOPR filed 10/1/2021		
	20M-0439G	Investigation Into Retail Natural Gas for GHG Emissions			
Massachusetts	20-80	Investigation by the DPU on its own Motion into the role of gas local distribution companies as the Commonwealth achieves its target 2050 climate goals		Massachusetts 2050 Decarbonization Roadmap (Dec 2020) 2030 Clean Energy and Climate Plan (Dec 2020)	2050 Roadmap ID's high-electrification as the least-cost pathway 2030 CECP states that Mass Save will work to phase out incentives for fossil fuel appliances by 2025

Minnesota	21-566	In the Matter of Establishing Frameworks to Compare Lifecycle Greenhouse Gas Emissions Intensities of Various Resources, and to Measure Cost-Effectiveness of Individual Resources and of Overall Innovative Plans	Notice of comment issued 9/3/21	Decarbonizing Minnesota's Natural Gas End Uses: Stakeholder Process Summary and Consensus Recommendations (July 2021)	
	21-565	In The Matter Of A Commission Evaluation Of Changes To Natural Gas Utility Regulatory And Policy Structures To Meet State Greenhouse Gas Reduction Goals	7/28: Centerpoint, CEE, Fresh Energy made a procedural proposal (which was filed in both 566 and 565) suggesting to suspend the 21-324 (where Centerpoint was applying for approval of RNG tariffs) proceeding in order to address the carbon accounting (for NGIA technologies) through public process		
Nevada	21-05002	Investigation Regarding Long-Term Planning For Natural Gas Utility Service In Nevada.	Procedural order filed 9/24/21	Pathways and Policies to Achieve Nevada's Climate Goals: An Emissions, Equity, and Economic Analysis (Oct 2020)	

New Jersey	GO20010033	In the Matter of New Jersey Natural Gas Commodity and Delivery Capacities in the State of New Jersey - Investigation of the Current and Mid-Term Future Supply and Demand	Opening order/notice of hearing filed April 20, 2021		
New York	20-G-0131	Proceeding on Motion of the Commission in Regard to Gas Planning Procedures	3.19.20 Opening order 8.10.20 Preliminary comments of Renewable Heat Now 2.12.21 Staff proposals on gas system planning and moratorium management 5.4.21 RHN Gas Planning Comments		No sector-specific ghg target; significant heat pump targets within efficiency programs
Philadelphia		PGW Diversification Study			
Washington	UG-210729	Consideration of whether to continue to use the Perpetual Net Present Value Methodology to calculate natural gas line extension allowances	Notice of item to be considered… filed 9/21/21	2021 State Energy Strategy	

Washington, D.C.	U-210553	Examination of energy decarbonization impacts and pathways for electric and gas utilities to meet state emissions targets		2021 State Energy Strategy	
	FC1167	In the Matter of the Implementation of the Climate Business Plan	WGL's compliance filing 9.1.21 (comments due within 60 days) Pepco's electrification study 8.27.21 (comments due within 60 days) Commission order No. 20754 lays out next steps		Carbon Free DC has identified the need to eliminate fossil fuel use in buildings, primarily via electrification (link)
Wisconsin	5-FE-104	Focus on Energy Quadrennial Planning Process IV	EE Potential Study filed 9.10.21		

9 APPENDIX D: ELASTICITY

The Fact Finding modeling suggests that under most scenarios all customers (residential, commercial, and industrial) will see cost increases in the near term. NWN modeling suggests that by 2040, under some scenarios, some customers would see a cost *decline*. However, given how far out in the future those cost declines are projected and the disagreement between NWN and the other gas utilities' models, Staff believes it is appropriate to plan for cost increases to customers under all scenarios proposed by utilities.

Part of what initiated the Fact Finding was the concern that as the energy system decarbonizes, low income customers would not only experience increases in fuel costs, but also be saddled with increasing costs associated infrastructure costs being spread over a smaller customer base. This, it was assumed, could be the result of decarbonization efforts that motivated more affluent customers to leave the gas system entirely and to switch to all electric homes. Staff conducted its own analysis of ratepayer bill impacts of natural gas decarbonization to better understand the extent to which this might warrant the use of policy intervention. That analysis follows.

10.1 STAFF's ELASTICITY ANALYSIS

Staff notes that if a natural gas utility raises its rates, natural gas customers are likely to change their behavior accordingly. These behavior changes can come in two possible forms:

- Changes in natural gas consumption
- Deciding whether to remain on the natural gas grid or seek alternative energy sources

The elasticity of natural gas consumption has been well studied in academic literature, particularly in the last few years. Using data from over 300 million household natural gas ratepayer bills in California and rigorous econometrics, Auffhammer and Rubin 2018 estimate that the residential natural gas consumption elasticity is between -0.17 and -0.23. Staff created its own econometric model using data aggregated to the state-year level and found an elasticity that is also near this range.

Aufhammer and Rubin break down the elasticity by season and by income and notes that low income households exhibit higher elasticity than high income households, and households in the winter exhibit higher elasticity than in the summer. These elasticity estimates vary from -.05 for high-income households in summer to -.52 for low-income households in the winter. This implies that should natural gas prices rise in response to decarbonization, low-income households in the winter are most likely to change their consumption patterns.

Staff conducted preliminary empirical modeling to investigate residential customers' propensity to connect or disconnect from the natural gas grid. Staff created an econometric model using annual data on state-level natural gas connections, residential natural prices, population and economic activity and various sets of controls. The econometric model assumes that residential consumers would not immediately change their equipment in response to a change in natural gas price, but instead do so after observing sustained price changes for multiple years. While Staff's results are preliminary and not corroborated by any known literature, they are suggestive of the following things:

- At an aggregate level, residential customers' natural gas connection decisions only react to a price change after at least 2-3 years. Absent outside pressures to connect or disconnect, it is unclear whether this reaction comes through existing customers switching natural gas connections to electric connections or new residential structures selecting non-gas heat sources.

- Regardless of the time lag, residential natural gas connection or disconnection appears to be highly price inelastic. Staff's preliminary model suggests that the price elasticity is approximately -.10. However, Staff reiterates that this value is preliminary and does not account for endogeneity of variables that likely biases the estimate in an indeterminant manner.

Due to data limitations, Staff's estimates do not account for any changes in technology or financial incentives that may reduce the costs to switch from natural gas to electricity. However, Staff's estimated negative elasticity implies that there will be some, albeit small, natural attrition from the natural gas system or slowdown in new connections if the push to decarbonize results in higher prices even without added incentives.

There is unfortunately also a gap in the academic literature regarding the elasticity of natural gas connections and disconnections, which makes it difficult to precisely determine the rate at which customers defect from the natural gas system. However, there has been recent research investigating the effects of the switch away from natural gas. Lucas and Hausman 2021 investigates who bears the cost of a declining utility and notes that a ten percent decrease in residential utility customers leads to only a five percent decrease in revenues, implying that the remaining utility residential customers bear a higher burden in costs. This is to say that should there be a large defection from natural gas utilities due to decarbonization, the remaining infrastructure costs will not scale down and will be paid by those remaining on the system.

What this suggests is that any cost increase is felt more acutely by customers that are already facing energy burden. Energy burdened customers' ability to respond to price signals appears to be limited to reduction in use, which in the case of gas used for heating, may result in a decrease in home comfort felt more by these customers than those who can maintain home heating expectations by either absorbing the cost increase, or ultimately changing heating sources.

10 APPENDIX E: SUMMARY OF STAKEHOLDER COMMENTS

UM 2178 Comment Summary for October 26, 2021, December 3, 2021, and June 3, 2022, Comment Periods

The following material attempts to summarize comments received in UM 2178 regarding the Report Draft, docket scope, and general policy positions. It generally does not capture the feedback received regarding the modeling and associated scenarios.

Table 14: Abbreviations – Organizations that submitted comments and that were referenced in the Comment Summary

Abbreviation	Organization
A Sherrett	Arlene Sherrett, Oregon Native and Climate Advocate
Avista	Avista Corporation
AWEC	Alliance of Western Energy Consumers
BE	Better Energy LLC
C Reed	Carly Reed
Climate Reality	Climate Reality Project, Portland Chapter
CNG	Cascade Natural Gas Company
CUB	Oregon Citizens' Utility Board
EDF	Environmental Defense Fund
JC - Mayoral	Joint Mayor City Official Letter
JC - CS et al.	Joint Comments - Climate Solutions et al. (29 Organizations)
JC - EC et al.	Joint Comments - Electrify Coalition et al. (41 Organizations)
JC - NWGA et al.	Joint Comments - NWGA et al. (17 Organizations)
LWVO	League of Women Voters of Oregon
JC - MCAT	Joint Comments - Metro Climate Action Team et al. (3 Organizations)
Multnomah County	Multnomah County Office of Sustainability
NRDC	Natural Resources Defense Council
NWEC	NW Energy Coalition
NWN	Northwest Natural
OPSR	Oregon Physicians for Social Responsibility
RNW	Renewable Northwest

SC	Sierra Club
TNC	The Nature Conservancy
Zero Coalition	Zero Coalition

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
1	Decarbonization	Decarbonize Planning	Study	NWN, RNW, and EDF discuss the importance of relying on economy wide decarbonization studies. RNW and EDF cite that an existing decarbonization study conducted by Evolved Energy support the role electrification plays in decarbonization in the Northwest. NWN states that such a study is still needed, and should be sponsored by the Commission, because the existing studies reference to date are not specific to the Northwest or are lacking in sufficient detail to fully understand the impacts of load shifting from electrification and goes on to describe what the study should include.
2	Decarbonization	EITE - Leakage		AWEC and JC - NWGA et al. expressed concerns about Emission Intensive Trade Exposed (EITE) leakage and impacts to the economy.
3	Decarbonization	Fuel-Neutrality	No fuel switch	NWN, JC - NWGA et al., and CNG all indicate that the PUC should remain fuel neutral. AWEC says decarbonization should be fuel neutral, based on facts and studies and consistent with state law; and NWN further states that the Executive Order (EO) 20-04 further establishes fuel neutral GHG reduction goals and calls out Renewable Natural Gas (RNG) as beneficial for Oregonians.
4	Decarbonization	Fugitive Emissions		BE and Climate Reality PDX state that the PUC should include life cycle emissions and capture fugitive emissions in its decision making. NWN states that is has one of the most modern pipeline systems in the US, that leaks are not an issue, and that its system is well prepared for hydrogen (H_2).
5	Decarbonization	Reliability		AWEC, NWN, and JC - NWGA et al. state that natural gas provides reliable, affordable, safe energy services for customers, including during peak loads and extreme weather. NWN cites the E3 decarbonization report stating that it concludes that natural gas companies serving existing and new customers while decarbonizing "is a cost-effective strategy to meet the region's climate goals while also reliably serving winter peak demands."

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
6	Direction/PUC Role	Commission Authorities / Responsibilities	Broader decarb authority	Environmental and climate advocates also assert that it is the responsibility of the PUC to protect customers, but that doing so necessarily means protecting customers from expensive or high-risk strategies taken by gas companies to meet climate policy obligations. They state that it is the responsibility of the PUC to ensure gas companies consider and deploy existing, proven technologies and strategies for reducing emissions, including supporting strategies such as fuel switching from gas to electric and ceasing socialization of gas line extension costs. They further state that the PUC has an obligation to protect customers, not maintain particular utility business models or protect gas company market share. (TNC, NWEC, CUB, JC - MCAT)
7	Direction/PUC Role	Commission Authorities / Responsibilities	Decision making/direction	Stakeholders opined on both the topics on which the commission should provide direction and the issues that should be considered in decision-making. Commenters generally agree that decisions should be based on the best available science, should be fact based, lawful, and within existing authority, although as mentioned above, there were differing opinions about how broad that authority is. Some stakeholders indicated that it was important that the PUC include public health and climate impacts in decision making. (See Comment Regulatory Tools – Beneficial Electrification 4). Commenters expressed frustration that the report did not provide more explicit direction to influence current IRPs and other PUC proceedings or future investigations. They argued that the PUC should be "decisive and proactive in implementing decarbonization policy and provide unambiguous direction based in climate science, available technology, and economic data (TNC). JC - CS et al. expressed concern that by allowing gas companies to continue to expand and allowing for consideration of alternative fuels to be used where electrification alternatives exist, the report puts a premium on flexibility that "abdicates the commission's responsibility to regulate." (See Direction/PUC Role Optionality 339).

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
8	Direction/PUC Role	Commission Authorities / Responsibilities	Limited decarb authority	Many commenters opined on the authority and responsibilities of the PUC, including regarding its general statutory obligations, its role with regard to policy implementation and leadership, its obligations to customers and utilities and associated least-cost, least-risk planning, PUC actions in relation to state climate policies, fuel neutrality, and obligations to public processes. NWN and Avista state that the PUC's authority is to ensure safe, reliable and affordable natural gas service and to remain fuel neutral. They explain that attempts to establish decarbonization mandates in the form of either reducing access to natural gas or effectuating declines in gas customers via electrification as means to achieving climate action goals is an overreach. They indicate that this falls into policy direction and that that is the purview of the legislature, not the PUC. Similarly, the JC - NWGA et al. further state that forced electrification and policies that phase out natural gas violate the regulatory compact and increase costs of energy for individuals and businesses.
9	Direction/PUC Role	CPP		LWVO suggests the PUC request that DEQ modify CPP for transport gas so that regulation lives with the party that can control the emissions
10	Direction/PUC Role	Customer count	Do not prohibit growth	NWN states that proposals that seek to reduce emissions by decreasing customers counts by prohibiting new hook ups go against the commission mandate to ensure safe, reliable utility services and that the Commission should focus on emission reductions specifically rather than on customer count limitations. It further states that the modeling demonstrated that there are cost effective compliance strategies that do not rely on prohibiting new customer hook ups.
11	Direction/PUC Role	Customer count	No growth	Multiple commenters expressed concerns about Staff seeking regulatory tools that allow for continued customer growth. They indicate that it was reasonable to assume that customer counts would decrease because the "market response to economic, climate and associated policy pressures" make for reasonable assumptions about consumer decisions to move away from gas" (CUB), that studies show electrification of space and water heating is a cost-effective emission reduction solution that is available today, that allowing for growth

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
				increases risk to gas customers both because it makes it more difficult and expensive to meet emission reduction targets, and increases infrastructure costs that they argue will inevitably be borne by fewer customers, who also will likely be Low-Moderate Income (LMI) customers less able to transition to electric options (JC - CS et al., CUB, NWEC, JC - EC et al., TNC,). Rather, they argue that at a minimum the Commission should not get in the way of customers that may want to fuel switch by limiting incentives to that could allow a switch, and that regulatory tools should be focused on how to manage declining customer counts.
12	Direction/PUC Role	Decarbonize Supply - general		NWN suggests that EO 20-04, 2019's Senate Bill (SB) 98 and 2013's SB 844 all demonstrate support for efforts to decarbonize supply.
13	Direction/PUC Role	Joint Planning		Many stakeholders commented on the need to perform some kind of joint utility planning or system-wide analysis and evaluation of GHG emission reduction approaches and the collaborative assessment of the impacts of electrification (Multnomah County, NWN, Avista, CNG, TNC, NWEC, NRDC, LWVO, JC - MCAT, Climate Solutions Joint Commenters pre-June 6, and BE).
14	Direction/PUC Role	Joint Planning		Some stakeholders provided additional guidance about what joint planning ought to include. JC - MCAT state it should include a timeline for building electrification, targeting of incentives for phased electrification, and phase decommissioning of gas. TNC notes that there should be a more formal coordinated planning process, beyond just shared assumptions and data. NRDC notes the process should develop "a combined "IRP" that begins with how loads can be met most effectively and cost-efficiently rather than how existing companies can best meet them for their customers." NWN and CNG both note support for collaborating with current electric Distribution System Planning filings on joint planning efforts. JC - CS et al. notes the Commission should task a third party to oversee a new joint planning process. NWN further notes that the scope of joint utility planning should closely engage with electric utilities to understand cost and reliability information to holistically understand costs of gas decarbonization efforts.

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
15	Direction/PUC Role	Optionality		NWN stresses the importance of optionality and not taking "premature" actions that could limit the development of nascent technologies, especially with regard to building electrification, noting that the E3 study demonstrates that "any rush to judgement on the future of gas is misguided and that rapid, wholesale electrification of building load is neither economical nor necessary for meeting Oregon's decarbonization targets." JC - CS et al. express concern that the Report's "premium on flexibility" abdicates the Commission's responsibility to regulate.
16	Direction/PUC Role	Prioritization	Focus on EE and Electrification	Stakeholders offered direction regarding how the Final Report and the Commission should prioritize its efforts. All commenters who spoke to this issue note the need to prioritize near term GHG emission reductions and the need to provide clear direction on ways to protect customers. TNC, NRDC, Multnomah County, JC - CS et al., and BE say the Final Report should focus on supporting low-risk solutions that result in near term emission reductions via regulatory tools that support the deployment of existing, proven, established, and cost-effective tools, citing energy efficiency, weatherization, and electric heat pumps targeted to LMI customers. JC - CS et al. additionally note that given limited Staff resources that the Commission should not use Staff time developing pilots that focus on hydrogen or other nascent technologies. TNC notes that EE and non-pipe alternative programs should prioritize GHG emission reductions by being fuel neutral and accommodating consideration of beneficial electrification. NWN states that regulatory tools should prioritize near term natural gas decarbonization efforts to meet CPP targets.
17	Direction/PUC Role	Prioritization		JC - CS et al. notes that all solutions should be CPP compliant, realistically available to achieve GHG reductions in the short term, and geared toward their best use
18	Direction/PUC Role	Protecting Customers	Flexibility & $	JC - NWGA et al. note heighten uncertainty during this time of transition and that this is "not the time for hurried decisions that could cost Oregonians for decades." CNG notes that programs to help customers should be flexible, be allocated funds, and focus on low income and energy burdened customers. And while NWN

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
				supports programs to protect customers, including implementation of HB 2475, it notes that its modeling showed it could comply with CPP without significant cost impacts to customers.
19	Direction/PUC Role	Protecting Customers	Implement tools to help customers	NWEC notes that UM 2178 should continue with an updated purpose on how to use tools identified to manage customer risk.
20	Direction/PUC Role	Protecting Customers	Protect customers, not gas utilities	NWEC, TNC, and JC - EC et al. state that the regulatory tools that the Commission considers should focus on protecting customers rather than what they perceive as protecting utilities by preserving gas customers and allowing for system growth. JC - EC et al. express concern that the report closely aligns with gas industry positions, and in doing so fails to protect customer interests. NWEC notes that the report devoted too much time to how to help gas companies reduce GHG emissions and not enough time considering the interests of customers. TNC notes that all commenters need to acknowledge that continued growth of gas customers is unsustainable and align incentives accordingly to protect customers associated with a gas customer declines. Further, Multnomah County and JC - Mayoral comments recommends considering the targeted resiliency co-benefit of cooling associated with programs that support the deployment of electric heat pump technologies to LMI customers. NWN's comments do not counter the need to protect customers, but they do point to the importance of protecting the viability of gas utilities to accomplish other GHG emission reduction goals. They state, "HB 2021 relies on the financial health of gas companies: Commission action that minimizes the number of customers who help pay for the state's gas infrastructure could inadvertently impact the financial health of gas utilities, irreversibly damaging the statewide benefits provide by OR gas system."
21	Direction/PUC Role	Regulatory tools		NWEC supports tools that can be implemented in the near term to protect customers.

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
22	Direction/PUC Role	Report Changes - Direction		Some stakeholders said that the Final Report needs to result in tangible direction from the Commission to the utilities, in many instances citing specific regulatory tools. NWEC notes that a key path to avoid customer risk is by providing guidance as soon as possible and note that the lack of guidance leaves customers at risk to either gas companies' failure to meet CPP targets or paying much more than necessary for energy services. JC - CS et al. note that where possible the Commission should not delay providing direction in the name of planning, but in doing so should be careful of stranded assets. NWN states that the modeling results were limited, which reinforces the need to stay with the existing regulatory process of "modeling, reporting, and follow-through."
23	Direction/PUC Role	Scope	Too broad	Throughout the docket, stakeholder discussed and challenged the proposed scope of the NGFF. Stakeholders continued to comment on the scope in response to the Draft Report. JC - NWGA et al., AWEC, and Avista state that electrification was beyond the scope of this docket and should not have been considered. Avista states the report takes an "anti-natural gas perspective" by including tools geared toward winding down natural gas business on the path to electrification. CUB, notes that the original objective as stated in the PUC's EO 20-04 workplan was not accomplished. They state the "EO 20-04 workplan includes ..."determine whether utility portfolios and customer programs reduce risks and costs by making rapid progress toward reducing GHG emissions" and prioritized proceedings and activities that advance decarbonization in utility sector to reduce GHG emissions." They further note the initial request from CUB for the NGFF was that it "provide guidance to IRPs about how to consider options for emissions reductions and the need to investigate how to minimize customer risk, including with stranded costs associated with impacts of policies that require GHG emissions reductions and further state the NGFF has not accomplished this. Rather, they state the NGFF has focused on gas company's ability to comply with CPP, where it should have included "...analysis of the future of natural gas within the PUC's proposed pathways to compliance with the EO directives, including

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
				utility planning framework (IRPs)." NWEC comments that it believed the Draft Report generally meets the state outcomes of the NGFF, but that exploring the optimal pathway for natural gas decarbonization is important, but secondary to protecting customers as we decrease GHG emissions.
24	Direction/PUC Role	UM 2178 Process	Next Step	TNC recommends opening an investigation for additional revenue decoupling and Performance Based Regulation (PBR) options to "reduce tension between policy goals and growth-oriented utility business models."
25	Direction/PUC Role	UM 2178 Process		CUB and NWN suggest the UM 2178 process needed additional opportunities for stakeholder engagement. CUB wants Staff to host the final workshop before the July 12 SPM so Staff can consider feedback from that workshop in the Final Report. NWN suggested that Staff add another comment period after the July 12 SPM.
26	Direction/PUC Role	UM 2178 Process		CUB comments that the final workshop, as noted in previous docket schedules, should be expedited and be held prior to the July 12, 2022, SPM.
27	Direction/PUC Role	UM 2178 Process		NWEC states that the next phase of UM 2178 should include "more robust independent analysis, active effort to overcome business as usual, and be laser focused on protecting customers in GHG constrained world."
28	Modeling	CCI Penalty		JC - CS et al. state that Staff's assumptions about cost of non-compliance should be increased. The CPP provides limited access to the use of CCI for compliance, so if the cost of non-compliance was just the cost of the CCI, that effectively permits unlimited purchases of CCIs. They argue the cost of non-compliance should be doubled or tripled.
29	Modeling	Decarbonize Supply - general		AWEC, NWN, and JC - NWGA et al. state that the modeling shows that gas companies can meet CPP targets by decarbonizing their fuel supply without electrification and that they should be given an opportunity to demonstrate compliance with this strategy. However, many stakeholders expressed concern that the utility assumptions were not adequately scrutinized by Staff and that analysis on RNG, and gas heat pump should come from a party other than the utilities. (See Regulatory Tools: Decarbonize Supply – RNG line #40)

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
30	Modeling	Electrification - Costs		Avista and CNG note that they did not report electrification bill impacts associated with reduced numbers of customers. Avista replied in comments that it should have included these impacts.
31	Modeling	Modeling	Unsupported claims / assumptions	Stakeholders identified issues regarding the modeling used for the Draft Report, including concerns about utility assumptions, concerns about inconsistencies in modeling and application of direction provided by Staff, and various weaknesses of the modeling itself. Many commenters stated that Staff did an inadequate job challenging the claims and assumptions associated with utility modeling and indicated that utilities played an outsized role in the process, and the utilities need to better support their claims (JC - CS et al., SC, CUB). Gas utilities noted that the process was rushed and that results should not be relied upon for decision-making, but NWN noted that of the modeling, the base case scenarios were most heavily scrutinized and should be relied upon over the alternatives. In particular, the electrification modeling was considered to be missing important information about load shift impacts, costs, and resulting impacts on the number of customers. Avista and NWN provide additional information about how to model electrification in future IRPs and stressed the importance of using more sophisticated modeling techniques (Plexos), and the need for data and information consistency. CNG notes that differences in electrification modeling may have been due to differing interpretations of the guidance from Staff and recommends Staff capture more detail about how electrification was modeled by the utilities. JC - CS et al. recommends moving more of the modeling findings from the Appendix to the body of the text.
32	Next Steps	CPP Compliance & Cost Allocation	Next Steps	NWN recommends and CNG stress the Commission open a docket to address CPP compliance and cost allocation. CNG states the investigation should carefully consider the role of sending appropriate price signals. AWEC adds that the principles of cost causation should be maintained in rate spread approaches.

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
33	Next Steps	Electrification Study		Avista, AWEC, NWN and JC - CS et al. describe the need to conduct an Oregon specific electrification study and provided details about what the study should include. This has also been referenced by other commenters as a beneficial electrification study.
34	Other	Business model		JC - CS et al. suggest that the regulatory tools presented in the report protected the gas utility business model and stated that the PUC should prioritize the public over protecting the existing, "unsustainable" gas utility business model. Others suggested the gas utilities should pursue other business models (e.g., carbon-free energy for industrial customers or green hydrogen for seasonal storage), but did not provide additional feedback on the role of the PUC in consideration or development of alternative business models (JC - MCAT, and A. Sherret).
35	Regulatory Tools	Beneficial Electrification		Many stakeholders stated that beneficial electrification was inadequately addressed in the report. Supporters of beneficial electrification would like the Final Report to address this topic in more detail and earlier in the document, and state that it should include a discussion about the direct and co-benefits of electrification as a decarbonization pathway, including public health benefits (JC - CS et al.). Whereas NWN indicates that beneficial electrification was presented as a viable solution without the inclusion of the full cost and implications to customers and stated that the report should "unambiguously" indicate that the full cost burden borne by energy customers was not considered.
36	Regulatory Tools	Decarb Planning & Cost Recovery		JC – MCAT et al. recommend the commission deny cost recovery for high-cost and high-risk investments in unproven technologies.
37	Regulatory Tools	Decarb Planning & Cost Recovery		The issue of cost recovery associated with CPP compliance was raised by a number of stakeholders. NWN, CNG and AWEC expressed concern about limiting cost recovery options for CPP compliance and stated that ensuring adequate cost recovery was critical to maintain safety and reliability, and the ability to bring lower carbon fuels on to the system, like H_2. They also expressed concern about connecting cost recovery with CPP compliance.
38	Regulatory Tools	Decarb Planning & Cost Recovery - Accelerated Depreciation		AWEC states that depreciation of assets should reflect the useful life of the asset and that inappropriately increasing or decreasing the time period over which costs are recovered is not in the best interest of customers. It says this assumes electrification as a future path without studying whether this is an appropriate

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
				assumption. CNG raise additional concerns, citing that changing asset depreciation timelines with anticipated use over a decarbonization timeline may be problematic for accounting purposes and may violate the matching principle. But it alternatively indicated support for "regulatory approval to accelerate depreciation expense since the assumption implies these assets will face obsolesce in the near future and the company would be faced with recovering fixed costs with smaller customer base."
39	Regulatory Tools	Decarbonize Supply - H_2		JC – MCAT et al., JC - CS et al., Multnomah County, NRDC, and NWEC expressed concerns about the role of H_2 in meeting CPP targets. They note that only Green H_2 should be modeled as a resource option, that the report erroneously assumes cost-effective availability of this resources for use in building heating applications, and does not adequately take into consideration a variety of risks, such as competition, redesign and replacement of pipelines and appliances, and stranded asset risks. Further, many stakeholders indicate that RNG and H_2 should be reserved for hard-to-electrify end uses. NRDC further notes that leveraging RNG and H_2 for home heating brings opportunity costs, because in an emergency, if a system fails, it is most likely replaced with the same, thus eliminating an opportunity to switch to electrification.
40	Regulatory Tools	Decarbonize Supply - RNG		There were disagreements about the assumptions of availability and cost of RNG as modeled by the gas utilities. CNG states the underlying market assumptions were consistent across all gas utilities, but that Staff should seek to understand differences in market adoption across different locations and demographics. However, other Stakeholders note discrepancies between the availability cited by the gas companies and that provided in a recent ODOE report, and further question the availability assumptions used by the gas companies. They indicate that biomass sources will be difficult to access and costly. Many of these stakeholders indicate that Staff needs to provide more scrutiny to the modeling done by utilities.

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
41	Regulatory Tools	Decarbonize Supply - RNG		If RNG and H_2 are to be used, stakeholders provided additional backstops and guardrails to help protect customers, including information about current and future development sites, confirmation that Renewable Thermal Credits can be used for CPP compliance, and close tracking of RNG market potential. Further Multnomah County states that the PUC should not allow expansion of the gas system unless utilities can demonstrate their ability to acquire RNG and Green H_2 in a cost competitive manner, and that they can demonstrate the safe use of H_2 before approval of any rate-based incentives. Additionally, in an effort to value RNG produced in OR, assessments should capture local benefits in Cost-Effectiveness calculations.
42	Regulatory Tools	Decarbonize Supply - RNG		NWN argues that utility activity is a driver of markets, so we should be careful to assume that general market reports reflect what is possible in the region. Further, both NWN and CNG support use of SB 844 to incentivize H_2 deployment. Avista notes that if SB 844 is to be used that the requirements need to be reevaluated to make it easier for gas companies to leverage.
43	Regulatory Tools	Decoupling / PBR		AWEC does not support PBR if what Staff means is crafting revenue stability for NG utilities that increases cost to ratepayers to encourage electrification.
44	Regulatory Tools	EE Avoided Cost (AC)		CNG and NWN support that CPP compliance costs should be reflected in energy efficiency avoided cost and align with CPP cost alternatives. NWN further states that the AC it will use in the current IRP and AC filings will be based upon CPP GHG costs. TNC adds that avoided gas infrastructure renewal costs should also be captured in EE AC. Multnomah County indicates that cost effectiveness "calculations should include AC of climate impacts and reducing emissions, and EE and non-energy benefits."
45	Regulatory Tools	Electrification - Choice		JC - NWGA et al. and NWN state that electrification policies eliminate customer choice and do not agree with Staff that electrification should be considered a compliance pathway.
46	Regulatory Tools	Electrification - Costs		There was substantial disagreement about the consideration of electrification costs in the modeling. NWN, JC - NWGA et al. state the high cost of electrification was not included and is currently unknown. NWN further indicates the need for further study and provides examples of what assumptions need to be considered, and states that its modeling shows compliance without electrification.

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
47	Regulatory Tools	Electrification - Costs		JC - EC et al. cites a Rocky Mountain Institute (RMI) report that studied electrification in Seattle that shows lower upfront costs for all electric homes but slightly higher annual utility ratepayer bills.
48	Regulatory Tools	Electrification - Fuel Switching		JC - CS et al., Multnomah County, and SC state the Commission needs to revisit fuel switching policies to allow Energy Trust and Community Action Agencies (CAAs) to engage in fuel switching, especially for Low Income (LI) and rural communities, and that fuel switching needs to be revisited in IRP Guideline Order (07-002).
49	Regulatory Tools	Electrification - General	Against	AWEC, NWN, and Avista were generally unsupportive of including electrification as a regulatory tool to be considered in the Final Report. NWN argues that the sources cited to support electrification were too generalized or based on states with very different attributes and should not be relied upon for assessing electrification impacts and costs. NWN further argues that because the case for electrification is unsupported, that inclusion as an option sends 'calamitous' market signals. They argue that the biggest risk of potential customer decreases and associated rate pressure increase are not from gas company compliance costs, but rather from policies that would drive customer defection.
50	Regulatory Tools	Electrification - General	For	Multiple stakeholders stated that the Draft Report does not adequately capture the role electrification can play in near term emission reductions, the likelihood of future electrification policies and actions, or the stakeholder comments addressing equitable transitions via building electrification and associated indoor air quality co-benefits with direct impacts to Black, Indigenous, and other Environmental Justice (EJ) communities. Further, some argue that while electrification is a preferred strategy for building decarbonization, the Commission should be prepared to protect LMI gas customers from anticipated negative cost impacts. (SC, NWEC, Multnomah County, JC - CS et al., and CUB).
51	Regulatory Tools	Electrification - Reliability		Avista is concerned about risks associated with load shifts from gas to electric but said both that electrification might take longer than stakeholders who support it realize, and that load shifts could make the electric system unreliable in peak times. Alternatively, JC - CS et al. and JC - MCAT believe arguments against electrification

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
				based on "reliability" are unsupported. They argue that switching resistance heating to electric heat pumps will largely address load concerns, and that even swift moves toward electrification will take time to implement, and reliability concerns can be addressed in long-term planning.
52	Regulatory Tools	Energy Trust Heat Pump		CUB states that funds coming from gas companies to Energy Trust should be used to conduct a conservation potential study focusing on how CPP emission requirements and costs of RNG affect cost effectiveness of energy efficiency. They indicate that it would include potential of NG heat pumps and would inform whether NG heat pump pilots are appropriate at this time.
53	Regulatory Tools	Energy Trust Heat Pump		NWN states the Commission will need to do more than direct Energy Trust. "The Commission and utilities will first need to address ETO budget development, as well as funding and delivery mechanisms for program expansion" e.g., expanded expertise may be needed.
54	Regulatory Tools	Energy Trust Heat Pump		NWN and CNG support Energy Trust training for both gas and electric heat pump technology. Joint commenters oppose the use of public funds for gas heat pump technologies, and many other commenters objected to public funds for gas heat pump technology promotion because of its relatively low commercial and technology readiness as compared to electric heat pumps. (See Regulatory Tools Technology Readiness line #83).
55	Regulatory Tools	Gas Infrastructure	Against	CUB, JC - EC et al., MCAT joint, and OPSR recommend an immediate halt of gas system expansion. Some specify that this just be the case for residential and commercial buildings. JC - EC et al. add that gas Line Extension Allowances (LEAs) should be eliminated immediately, and that the PUC should investigate the opportunity to "branch prune" sections of the existing gas system and replace those portions with electric heating. CUB states that the Report's suggestions that gas system expansion is necessary to protect customers should not be treated as fact. CUB further provides a cost comparison showing that reducing customer count reduces utility revenue by about $70-100/year, but that it is offset by reducing capital investment of about $2500. It would take more than 20 years for the additional customer charge to pay for the cost of the capital investment, creating a stranded cost risk if that customer later converts to an electric heat pump.

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
56	Regulatory Tools	Gas Infrastructure	For	NWN disputes the claim that investments in gas infrastructure will lead to stranded assets, and JC - NWGA et al. support decarbonization polices that embrace innovation and make use of existing energy delivery infrastructure.
57	Regulatory Tools	GHG Emission Reductions		NWN argues that a rush to electrification could increase emissions in the short run because of the current mix of electric generation and inhibit large-scale emission reductions in the long run. They cite an E3 Study - Pacific Northwest Pathways to 2050 the company commissioned in 2018. The company also notes that electrifying all natural gas high efficiency heat pumps would reduce OR emissions by less than 1 percent while increasing customer heating bills.
58	Regulatory Tools	Incentives - eliminate gas incentives		JC - EC et al., JC - CS et al., Multnomah County, Zero Coalition and JC - Mayoral comments indicate that the report should include the elimination of subsidies or incentives associated with the development or promotion of gas system expansion, gas heat pumps, or renewable natural gas. NWEC further states that the PUC does not need to incentivize anything because CPP is law and that the role of the PUC is to ensure compliance and make sure customers pay fair, just, and reasonable rates.
59	Regulatory Tools	Increase access to information		Comments regarding increased access to information were all generally supportive, the primary exception was with regard to mapping (see Regulatory Tools – Mapping lines #66 and #70). NWN notes that notices and quarterly update requirements should apply equally to gas and electric companies. JC - CS et al. notes that the Commission should direct utilities to host public workshops for lay audiences including explanations of the planning process, how the models work, and how to understand utility investments. They further note that staff should produce manuals on how to effectively participate in various proceedings, particularly IRPs.
60	Regulatory Tools	Innovation	For	NWN, CNG, AWEC, and JC - NWGA et al. believe the PUC should encourage gas companies to innovate to reduce emissions. AWEC notes pilot programs could be beneficial for hydrogen and CCSU but cautions that pilot programs costs should be fairly allocated between shareholders and rate payers, noting that traditional ratemaking paradigms might not work. JC - CS et al. indicate support for innovation only for hard to decarbonize end uses, not on residential or commercial heat. NWN notes that the Commission would need to provide

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
				additional clarity on goals of the pilot to ensure benefits to both gas and electric are explored.
61	Regulatory Tools	Innovation - Green H_2	Against	CUB, JC - CS et al., and NWEC were generally not supportive of incentivizing Green H_2 pilots and cautions against other pilots. JC - CS et al. indicate that ratepayers should not pay for alternative gas pilots at the expense of leveraging proven technologies, that new technologies take time to commercialize and scale to be effective, and that innovation should be funded by investors, not ratepayers. CUB argues that pilots should not be used for gas heat pumps and that doing so interferes with Energy Trust's analysis on potential, that NEEA is already conducting analysis in this space, but has not yet run a pilot, and that because there are no commercially available natural gas heat pumps for the residential market, that it does not make sense to run pilots with them. NWEC notes that the Commission has a long history of not supporting customer funded R&D, and this should continue as there is sufficient federal and private support for Green H_2 research. Further, the Commission should focus on directing the utilities to do things they would not otherwise do, such as implementing electrification and placing limits on new customer hook ups.
62	Regulatory Tools	IRP	Appendix B	NWN and Avista recommend against implementing IRP recommendations included in Appendix B in current IRPs via a waiver. NWN states that the IRP process has been vetted and that adding elements via a waiver risks adding unclear and unvetted requirements into an established process, which may produce flawed results. Additionally, NWN notes that allowing waivers might undermine the validity of the IRP guidelines and circumvent the public process. JC - CS et al. suggests that Appendix B should feature more prominently in the report, highlighting the need for tangible near term direction from the Commission regarding IRP analysis.

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
63	Regulatory Tools	IRP	Appendix B	Some commenters note concerns about the fact that all three gas utilities are in the process of developing their IRPs and recommend elements of Appendix B and any other applicable IRP related recommendation be implemented in the current IRPs (NWEC, LWVO, SC, CUB). NWN and Avista note that some of the changes proposed for IRPs in Appendix B are likely non-controversial, but they should not be applied to the current IRPs because there has not been a public process to discuss these changes and, in NWN's case, the IRP is too far along to make some of the changes requested. NWN also states that it is premature to take any action from UM 2178 that might undermine NWN's IRP action plan.
64	Regulatory Tools	IRP	CPP Acknowledgement	Regarding CPP compliance being acknowledgeable in IRPs, CNG and NWN agree that it should be acknowledgeable. JC - CS et al. however say CPP compliance should be mandatory, not just acknowledgeable.
65	Regulatory Tools	IRP	Elements	Many stakeholders convey differing positions regarding particular elements being included in the next round of IRPs. CNG notes that CPP compliance bill impacts should be included but should include uncertainly levels and a focus on near term action items and to the extent possible, CPP compliance costs should carry over into electric IRPs. Avista notes that demographic information should not be part of the IRP but should be with EE and energy assistance discussions and reporting. Avista also notes that gas companies would not know information about space and water heating across its territory, but that a consultant could be hired to find this information. It also notes that it would not know new technology adoption rates. NWN states that Marginal Abatement Cost curves should not be required in IRPs because they are not "sufficiently detailed to make accurate determinations about relative cost effectiveness of specific investments or actions."
66	Regulatory Tools	IRP	Proceeding	NWN, CNG and AWEC state that to consider changes proposed in Appendix B regarding IRPs that the Commission should open a proceeding on IRP guideline changes, pertaining to both gas and electrics. NWN notes that companies need to work with the Commission and stakeholders to develop a uniform methodology for converting IRP investments into ratepayer bill estimated impacts. NWN notes that the consideration of marginal abatement cost curves should be discussed in

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
				this broader IRP proceeding. CNG notes that modeling assumptions should be a topic when considering modifications to the current IRP process. Joint Climate Solutions comments prior to June 3 note that the IRP guidelines need to be updated to better capture emerging risk and uncertainty and that IRPs should require an analysis of fuel switching.
67	Regulatory Tools	IRP - Electrification	Electrification	JC - CS et al. state that that the Commission should develop and provide more direction about how gas companies should consider electrification in IRPs, including requiring that IRPs have realistic electrification scenarios and the ability to analyze stranded asset risk. They state the Commission should at least direct gas companies to conduct low, medium, and high electrification scenarios and identify cost impacts.
68	Regulatory Tools	Line extension allowances	Change/Eliminate	JC - CS et al. and NWN note that the Line Extension Allowance recommendation provided in the Draft Report needs clarification. JC - CS et al., TNC, and JC - EC et al. state that LEAs for gas companies need to be phased out immediately and that those for electric utilities should be revisited to consider behind the meter upgrades that support electrification. CNG and AWEC note that LEAs should be based in sound economic, and rate making principles (equity among rate payers and cost causation) and not be used to effectuate electrification without further conversation about decarbonization strategies. Regarding the process proposed by Staff in the recommendation, NWN says the Commission should refrain from making 'interim' changes, and TNC notes that discussions about LEA changes should allow stakeholder input.
69	Regulatory Tools	Mapping		NWN and Avista do not support providing infrastructure maps, stating that it is a security issue, the information Staff is seeking is not available, and that utilities use “group method” accounting and depreciation, so they do not track every asset or depreciable life. Avista also notes that the mapping information about depreciation would not be consistent with publicly available data from the Company's depreciation studies, which are provided every 5 years. NWN further notes that if maps are required that Staff should explain the goals of the mapping

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
				to enable constructive discussion and that requirements should apply equally to gas and electric utilities. CNG states that it does not believe additional mapping proposed by Staff provides value, given the effort required and notes that Staff should clarify the value of the mapping proposed.
70	Regulatory Tools	Mapping		JC - CS et al. states that maps of the gas system should help inform opportunities to prune the system with electrification.
71	Regulatory Tools	Monitoring, Tracking and Reporting	CPP Reports	Regarding monitoring, tracking and reporting, stakeholders commented on the urgent need for rulemaking to determine the cadence, form, and data required for CPP reporting and alternative fuel related reporting (RNG/ H_2). CNG indicates a preference for leveraging existing platforms such as IRPs and Purchased Gas Adjustments. NWN further comments on the need for "well-designed measures to monitor utility compliance" that should be accompanied by cost recovery that enables compliance. It states that lacking clear standards for cost recovery for investments makes compliance more challenging because it sends negative signals to "much-needed investors in Oregon's energy future...". NWN also stresses the urgency of initiating CPP reporting rulemaking. JC - CS et al. supports monitoring, tracking, and reporting, but cautions against prioritizing this such that it delays action.
72	Regulatory Tools	Programs		Climate Solutions Joint comments submitted prior to the Draft Report recommend a series of program related tools. They include: promote shell and weatherization improvements; eliminate incentives for methane gas measures; prioritize LMI, EJ - rural opportunities, rental units; heat pumps for LMI; include public health and climate impacts program/measure design; align funding for EE with least-cost decarb pathways; and remove barriers to Energy Trust conducting beneficial electrification.
73	Regulatory Tools	Programs		NWN, Avista, and CNG support the expansion of EE programs to assist in least-cost, least-risk CPP compliance. Avista notes that this will require a review of EE cost effectiveness assumptions for avoided cost calculations.

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
74	Regulatory Tools	Programs		JC - CS et al. comment that 2/3 of the program recommendations encourage gas system growth, namely EE measures that allow for customer hook-ups and EE programs for transport customers.
75	Regulatory Tools	Protecting Customers	Recommended tools	JC - EC et al. suggest specific actions and tools to be considered to protect customers, including accelerating amortization schedules, denying rate recovery for investments in unproven technologies, and implementing rate class policies (HB 2475). However, Multnomah County notes that HB 2475 has limitations and is not sufficient protection for vulnerable customers from upward rate pressure.
76	Regulatory Tools	Protecting Customers - participation	Outreach	Zero Coalition recommends expanded outreach and reduced administrative burden for BIPOC, tenants, and LMI populations to facilitate participation in incentive programs.
77	Regulatory Tools	Rate Spread/design		CNG and NWN note the need to consider rate design and rate spread in a near term proceeding on CPP compliance and that it should include consideration of how to handle transport customers. CNG notes it is supportive of alternative rate design mechanisms if they promote positive outcomes and maintain safe and reliable service while protecting customers. CNG notes it prefers voluntary conservation based on price signals and enrollment in conservation programs provided by the company.
78	Regulatory Tools	Rates		NWEC and JC - CS et al. indicate support for the rate tools being considered. Climate Solutions joint comments prior to the Draft Report suggest the Commission should consider Multi-year Rate Plans, Performance Incentive Mechanisms, securitization, as well as heightened scrutiny of the impact of new infrastructure investments. However, JC - CS et al. note that the Commission should not let ratepayer risk "slow energy transition progress."
79	Regulatory Tools	Reduce Demand - EE	Expand EE Offerings	Expanded EE offerings was consistently supported by stakeholders who commented on the topic and expanded support for Energy Trust was regularly cited as a path by which this should be accomplished. Avista notes that Energy Trust does not provide LI weatherization, that CAAs do, but that they have been limited in their ability to meet demand for weatherization. They note that expanded outreach will not address this, rather that new solutions are needed to serve LI customers with weatherization. JC - CS et al. note that EE program spending should only be for insulation, shell improvements, and electrification.

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
80	Regulatory Tools	Reduce Demand - Electrification	More focus on electrification	Multiple stakeholders note that the Final Report should more thoughtfully address electrification as a core decarbonization strategy (Zero Coalition, TNC, JC - NWGA et al., Multnomah County, MCAT Joint, and BE). However, JC - NWGA et al. state that electrification does not equate to decarbonization. Several stakeholders cited multiple sources and studies that show that electrification of water and space heating is the most cost-effective way to decarbonize buildings (MCAT joint, Zero Coalition, and BE). SC notes that utility planning related to electrification is within the sphere of influence of the PUC, whereas guaranteeing an affordable and available supply of RNG is not.
81	Regulatory Tools	Regulatory tools		JC - CS et al. provide a list of tools that should be captured in the Final Report, including: phase out gas LEAs; update Energy Trust policy to remove artificial barriers so gas and bulk fuel customers can choose to transition to more-efficient electric options; Expand low-income weatherization programs to allow for funds to be used for low-income electrification options and/or create a pilot program to encourage equitable electrification for LMI households; Continue and expand current efforts to ensure robust low-income ratepayer protections; and explore the value of pruning to strategically resize the gas system where it is aging, inefficient, or requiring significant and expensive upgrades. They further note that ratepayer bill impacts should be differentiated by LMI.
82	Regulatory Tools	Report Changes - Direction		CUB states the docket should have included investigation of: "no pipes solutions; line extension reform; useful lives and depreciation curves; discouraging incentives to switch from electricity to gas; reallocating investment risk; and fuel switching."
83	Regulatory Tools	Technology Readiness		Many stakeholders commented that the Final Report recommendations should rely on proven technologies that exist in the market today, which are more readily available to reduce GHG emissions, are less costly, and less risky. Staff should also consider ways to further incentivize use of existing GHG emission reduction technologies, namely energy efficiency, weatherization, electrification. (CUB, JC - EC et al., JC - CS et al., JC - MCAT, NRDC, TNC). Alternatively, NWN notes that

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
				utilities like NWN drive market trends and that the Commission should strongly encourage near-term investments in promising new decarbonization strategies.
84	Regulatory Tools	Third Party Support		AWEC, CNG, and NWN provided comments regarding the use of third-party consultants to inform technical and market assumptions. AWEC notes that said party should be unbiased and fuel neutral. CNG notes said party should be selected via a transparent process with stakeholder participation, and that results should be informational, not prescriptive. NWN seeks clarification from Staff on how the findings would be used and expressed concerns about generic reports not being representative of what is possible via utility driven investments and that such an analysis could hinder encouragement of reasonable investments in nascent technologies.
85	Regulatory Tools	Transport - EE		AWEC, Avista, CNG, and NWN commented on the need for EE programs for transport customers and highlighted some of the challenges that will need to be considered. NWN notes that the challenges and regulatory considerations warrant opening an "industry-wide" proceeding on EE programs for transport customers and the PUC's regulatory authority over this customer class. The issues include how to fund, implement, and administer such a program and how to address associated compliance costs and rate spread. AWEC further provides suggestions for a "Large Customer Carbon Reduction" program (AWEC pg. 3-5)
86	Report	Analysis and Conclusion		CUB states the report lacked analysis and scrutiny of utility modeling or assumptions; it did not include any findings on the modeling or provide ratepayer bill impacts; it did not include consideration of feedback and data from stakeholders; nor did it provide conclusions regarding appropriate tools to mitigate potential customer impacts.
87	Report	Climate and health risks	Public health	JC - CS et al., OPSR, and TNC want the Final Report to include more information about the public health harms of methane gas use.
88	Report	Climate and health risks	Urgency	JC - CS et al. and JC - Mayoral comments indicated that the Final Report should better reflect climate urgency and the science supporting the need to rapidly, substantially, and continually reduce methane emissions. They indicate that the Final Report should better reflect climate urgency in its justification and prioritization of regulatory tools.

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
89	Report	Costs		Regarding CPP costs, AWEC indicates that decarbonization goals should consider the cost of compliance for consumers in Oregon. However, NWEC and JC - CS et al. express concern that this investigation's focus on compliance costs, and less on the benefits of CPP compliance, might be used as an attempt to challenge the CPP rules. They caution the PUC about making statements about cost without knowing overall energy costs, energy burden, and tradeoffs. Additionally, many commenters indicate that it was important that the Final Report couch CPP compliance cost in the context of the benefits provided by the CPP.
90	Report	Elasticity		CNG and JC – CS et al. wants Staff to share its econometric model on elasticity or move the elasticity report to the body of the text.
91	Report	GHG Emission Reductions		BE, Climate Reality PDX, and Multnomah County state that the climate crisis requires that the Commission focus decision making on emission reductions. CUB states that gas companies have yet to demonstrate their ability to reduce emissions with existing customers "let alone accommodate growth and increase load." And JC - MCAT state that the Draft Report's "all of the above" approach is contrary to OR statewide energy policy, citing CPP rules and further notes that Staff's recommendations fail to facilitate GHG emission reductions. JC - EC et al. note that actions proven to reduce emission from gas utilities and protect ratepayers are: 1. Eliminate further expansion of the gas system; 2. Reduce the quantities of gas that are consumed by existing gas customers; and 3. Replace methane combustion with less polluting, high efficiency electric heating wherever possible.
92	Report	Reduce Demand - Electrification: Trends		Multnomah County and JC - EC et al. note that policy and customer choice will increasing lead to electrification of end uses. JC - EC et al. cites cities, counties, and states enacting building codes supporting a move to electrification.
93	Report	Report Changes	Clarify	NWN, Avista, and CNG request clarification on select recommendations and other aspects of the report and indicate that Staff should allow commenters to respond to clarifications before any PM addressing the Draft Report. Recommendations that need clarification include: - Rates 5.1.1(6): Align near-term investment levels with annual progress in CPP compliance in order to limit uncertainty around accumulation of long-term capital assets.

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
				- Rates 5.4(3): Explore linking the amortization of CPP compliance costs from deferrals to actual CPP performance. TNC indicates that Staff's recommendation regarding cost recovery associated with CPP compliance and CPP amortization links to CPP performance was unclear.
94	Report	Report Changes	Clarify	CNG notes section 3.2.2 regarding transport customers should explicitly exclude electric generation customers and be indicated as such.
95	Report	Report Changes	Clarify	CNG notes the Final Report should clarify whether the elasticity relationship is evaluated relative to gas prices, ratepayer bills or utility rates.
96	Report	Report Changes	Clarify	For section 4.3, fifth bullet – Avista notes it is unclear what is meant by "business model motivation" and aligning utility behavior with transition targets. Additional detail should be provided to articulate what this bullet is attempting to portray.
97	Report	Report Changes	Correction	Avista notes that in Table 5 - alternative Supply Projections the RNG Supply Penetration by 2035 - the Avista column incorrectly states 40 percent of overall deliveries – it should state 19.5 percent.
98	Report	Report Changes	Correction	Avista notes that Avista's general rate revision proposal does not include a differential rate proposal. Avista is proposing to implement a ratepayer bill discount program pursuant to HB 2475, but it is outside of its general rate case.
99	Report	Report Changes	Correction	Avista notes that it is not necessarily true that compliance with the CPP will likely increase costs to all customers in the near-term.
100	Report	Report Changes	Correction	Avista notes that its compliance cost had been added to the price per dekatherm of natural gas available as supply into the Company's system and may not be indicative of actual rate spread.
101	Report	Report Changes	Fact Check	Avista notes that the Draft Report incorrectly states the CPP lays out framework that "prohibits supply of natural gas."
102	Report	Report Changes		JC - CS et al. state that the background section should include how other states (MA and CA) are addressing future of gas.
103	Report	Report changes - momentum		Avista and JC - CS et al. noted they both disagreed with the language characterizing natural gas 'momentum'.

Ln	Feedback Issue	*Topic*	*Subtopic*	Summary
104	Report	Report Changes - Stakeholder Feedback		Many stakeholders commented that the Draft Report disregards stakeholder feedback and data and does not provide justification for Staff positions with regard to stakeholder feedback and data. This includes, but it not limited to modeling, electrification, RNG/ H_2 assumptions, and natural gas heat pumps. (CUB, JC – EC et al., JC – CS et al., TNC, Avista)
105	Report	Report Changes - Unsupported claims		Multiple stakeholders note that the Draft Report contained unsupported or unsubstantiated claims and challenged whether the report accomplished its goal of fact finding. JC - CS et al. notes that the Report fails to "meaningfully parse through the discord between gas utilities' analysis and recommendations, and those of third-party experts and community stakeholder to come up with actual facts." NWN comments that its decarbonization pathways are credible and supported by facts. CUB notes that the Final Report should detail and weigh in on compliance scenarios informed by utilities, but also market and industry data, science-based information, stakeholder input, and PUC experience. CUB further notes that the Final Report should clearly indicate where issues were in dispute and/or explain the basis for Staff conclusions where issues were in dispute.
106	Report	Risk		Multnomah County, JC - CS et al., JC - EC et al., and Avista commented that the Report inadequately addressed various risks. JC - CS et al. notes the report should better capture uncertainty regarding various CPP compliance strategies and that the Report inaccurately reflects the risks of electrification as being on par with the risks of decarbonizing gas; Multnomah County says the Report should better reflect environmental and financial risk of failing to decarbonize the gas sector; and JC - EC et al. state the PUC should address emerging risks of CPP non-compliance by adopting least-cost, least-risk strategies proposed by stakeholders and RAP. Avista notes that the risks associated with electrification as a CPP compliance strategy has not be adequately addressed in the Report.

11 APPENDIX F: DISTRIBUTION SYSTEM PROJECT INFORMATION IN FUTURE GAS IRPS

Staff seeks the analysis and information on proposed distribution system upgrades to determine rationale and thus inform acknowledgability under the CPP. Specifically, Staff seeks:

- An understanding of the model parameters used to identify and justify an upgrade.
- Information to assess model performance against observed conditions at the proposed upgrade location, including scenarios and probability of those scenarios, e.g., Number of Heating Degree Day in targeted years at the investment location
- Minimum standards for operation around the proposed upgrades
- Alternative activities or investments analyzed or already enacted, particularly focused on minimizing growth of overall throughput of the network
- If a distribution system project was selected over an alternative investment, the rationale supporting the selection

Staff has developed a set of questions, akin to standard data requests, divided into four categories, with the goal of helping to guide the information submitted about distribution system projects and clarify expectations. To the extent that any gas company's IRP omits this analysis and information, Staff may ask for it in Information Requests.

Distribution System Upgrade, Model Basics

Goal: To help Staff and stakeholders understand fundamental modeling assumptions used by the Company to assess distribution system upgrades and the logic used to model a system, identify upgrades, and assess alternatives to upgrades.

1. For any proposed distribution system project provide the following in Excel format with formulas intact:
    a. Model parameters,
    b. Customer-temperature correlation and confidence, particularly focusing on those customers for whom correlation is not high (e.g., non-temperature dependent use types),
    c. HDD scenarios considered and the influence of more extreme use cases,
    d. Minimum delivery pressures, and
    e. Correlation and confidence of location-specific temperature cases.

Distribution System Upgrade, Ground Truthing

Goal: To help Staff and stakeholders understand how well a model reflects actual conditions observed at the location of a proposed distribution upgrade. This helps to establish confidence in the need for a project.

2. Describe **how** the Company assessed model accuracy for pressure recordings and weather data against actual observations.

3. Provide data demonstrating how modeled conditions appeared in observations. This should include:
    a. A description of when they happened;
    b. Locally measured temperatures and other relevant weather parameters;
    c. How often they happened;
    d. How long they were observed for; and
    e. Clarification about whether during the observations any contingency actions were deployed, including but not limited to curtailing interruptible customers, effecting cold weather actions (i.e. bypassing regulator stations), local injection of gas, or the use of any energy efficiency or demand side management approaches.

4. Provide data supporting where in the system the largest line losses occurred to determine the best mitigation for the reduced delivery pressure cases.

Distribution System Upgrade, Minimum Standards

Goal: To help Staff and stakeholders gain insights into the engineering and operational standards under which a utility seeks to operate its distribution system. These standards provide a better understanding of the extent to which the current system falls outside of those standards and how the proposed upgrades address those issues.

5. Provide the following information for each category of a utility's system
    a. High pressure distribution system:
        i. Maximum allowable operating pressure (MAOP)
            1. Limiting component(s)
        ii. Specified minimum yield strength (SMYS)
        iii. Normal operating pressure
        iv. Minimum operating pressure
        v. Standard pipe sizes, materials, and grades
        vi. Minimum cover depth
        vii. Main pipeline leaks by grade
        viii. How many leaks are carried over from prior calendar year by grade
    b. Intermediate pressure distribution system:
        i. Maximum allowable operating pressure
            1. Limiting components
        ii. Normal operating pressure
        iii. Minimum operating pressure
        iv. Standard pipe sizes, materials, and grades
        v. Minimum cover depth

vi. Main pipeline leaks by grade
vii. How many leaks are carried over from prior calendar year by grade

c. Industrial services:
i. Maximum allowable operating pressure
ii. Normal operating pressure
iii. Minimum operating pressure
iv. Standard pipe sizes, materials, and grades
v. Minimum cover by grade
vi. Service line leaks by grade
vii. How many leaks are carried over from prior calendar year by grade

d. Residential and commercial services:
i. Maximum allowable operating pressure
ii. Normal operating pressure
iii. Minimum operating pressure
iv. Standard pipe sizes, materials, and grades
v. Minimum cover depth by grade
vi. Service line leaks by grade
vii. How many leaks are carried over from prior calendar year by grade

6. For each project identified outline:
a. Existing maximum allowable operating pressure.
b. Proposed maximum allowable operating pressure.
c. Normal operating pressure.
d. Design day (hour) minimum pressure and related HDD.
e. All data supporting the validation of the local network model, including pressure recording charts.
f. The model under the variety of cases with various thematics, including delivery pressures and line losses.
g. Cathodic protection records demonstrating the effectiveness of the program for this corridor.
h. Leak history for transmission, distribution mains and service lines by grade.
i. If cover or other safety or reliability concern is relevant to the project's completion, please identify the data supporting that concern. For instance, in the case of insufficient cover, provide evidence of how pervasive the cover limitations are, e.g., pothole history or other supporting material. If any metal coupons of the pipeline have been tested, please provide such information.

Distribution System Upgrade, Cost Effective Alternatives

Distribution system upgrades that can increase emissions put financial pressure on ratepayers and the Company to reduce emissions elsewhere on the system. Thus, resource planning in Oregon must now explore the extent to which upgrade alternatives that forestall or even avoid expanding distribution system capacity were explored. The questions below seek to establish the alternatives explored, how they were identified, and, if applicable, why distribution system upgrades were selected over the explored alternatives.

1. Describe the alternatives to distribution system investments that were explored as part of the Company's research.

2. Identify the frequency with which the Company has performed contingency actions to ensure proper system delivery, such as bypassing regulator stations, injecting CNG or other measures. For each time such actions were taken, provide all supporting records about the actions taken.

3. List the number of interruptible customers and their hourly maximum demand, as well as any curtailments conducted during peak events. Additionally, describe how much each interruptible customer is estimated to use at peak and how the model used for distribution system upgrades incorporates the interaction with interruptible customers when assessing the size and timing of a distribution system upgrade, especially a gate upgrade.

4. Identify the extent to which the Company analyzed the potential for large loads in the area of the upgrades to either shift or be shed during peak events to avoid upgrades.

5. Identify the extent to which the Company analyzed the use of energy efficiency and/or demand response (e.g., thermostat pre-heating or reducing peak demand) programs to forestall or avoid the proposed upgrades. If such analysis was conducted, please summarize the impact on the size and timing of any of the proposed upgrades and why such energy efficiency and/or demand response was not pursued.

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TO: puc.publiccomments@puc.oregon.gov

SUBJ: Public Comment Regarding UG 527, UG 528, and UM 2419 - Coos County Pipeline

Chair Tawney and Commissioners Perkins and Powers,

Thank you for the opportunity to comment on UM 2419 in regards to the gas pipeline sale to NW Natural in Coos County. Rogue Climate serves and works alongside Southern Oregon and South Coast communities most impacted by climate change, including low-income, rural, youth, and communities of color, by organizing for clean energy, sustainable jobs, and a healthy environment. We do so through leadership development, political education, and campaigns for policies that benefit our communities.

For the past 7 years Rogue Climate's South Coast team has been organizing with Coos County community members to build a vision of a thriving and resilient future for the South Coast. Through listening sessions, gatherings and surveys, we heard that community members envision a future in which people, the economy and the ecosystems that sustain them are cared for. They envision affordable and abundant housing, clean air and water, and resilience in the face of rising sea levels, temperatures, fires and floods. Community members want reliable, affordable and renewable energy.

The Coos County Pipeline sale is an opportunity to gradually decommission this faulty infrastructure while investing in solutions that would increase energy efficiency and cost savings for coastal Oregonians. The history of this pipeline proves it is a poor investment that has lacked community support from the beginning. The pipeline poses a substantial safety and economic risk, threatening leaks that could cause substantial damage to the community and fragile coastal ecosystems – especially in a region that is expected to be severely impacted by natural disasters such as a Cascadian subduction zone earthquake event and/or tsunami. Already, Coos County taxpayers have been investing in this failing infrastructure without much benefit. The cost of further upgrades to the pipeline would pose an additional burden on NW Natural's customers across the state who have already seen exorbitant rate increases in past years. Coos County deserves investment in energy resilience through robust transmission upgrades and energy efficient electrification, rather than locking in fossil fuel infrastructure that pollutes the air and takes Oregon further away from our climate goals.

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The average household income in Coos Bay is $55,292, highlighting the need for affordable sources of energy that can keep homes safe during any weather. 30-39% of households in Coos county are facing severe energy burdens while also earning less than $15,060 per year.
As extreme weather events become more common, from heat waves to ice storms, families on the South Coast are increasingly burdened by high energy costs and power outages, highlighting the urgent need for affordable, climate-resilient solutions. As more and more customers across the state move off gas and choose more affordable and efficient energy sources, rural communities locked in to natural gas reliance will be forced to pick up the cost, resulting in skyrocketing bills.

Now is the time to invest in energy resiliency for the South Coast. In alignment with the Oregon Energy Strategy and Governor Kotek's recent Executive Order 25-29, communities across the state are shifting away from fossil fuels towards renewable, reliable, and affordable electricity. Expanding access to heat pumps, solar generation and storage, and home generation are essential steps to ease the transition. Investing in microgrids would help to prepare Coos County for disasters and workforce development programs would support projects that bring sustainable, high-paying jobs to the region. The Oregon Energy Strategy underscores that the cost of the energy transition will only increase with further delay.

Rogue Climate has seen firsthand how ductless heating and cooling pumps reduce energy use, lower utility bills, and support our communities to be safe and healthy. Heat pumps can provide pollution-free cooling during more frequent extreme heat on the coast, transition households away from reliance on bulk fuels, create jobs for local HVAC installers, and reduce rural energy burden. Rogue Climate's Energize programs in Coos, Douglas, Jackson, Josephine, and Klamath counties over the past 10 years demonstrated the high demand for efficient heat pumps and the great benefit to community members when this technology is accessible to low-income and rural households. Over the course of the Energize South Coast program, we trained more than 300 South Coast residents and installed affordable DHP's in 75 households in Coos County. The program was so popular, we had to hire a second contracted installer to meet the demand. The average participant experienced reductions of 50-75% in their utility bills. Plus, dozens of family-wage jobs were created with local installers.

The maintenance and repair costs of this pipeline would fall unfairly on residential rate-payers. The Coos County Pipeline currently serves around 1,700 residential customers, however, the

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largest users are commercial: the essential but underfunded Bay Area Hospital and Rosburg Forest Products, a failing timber business that ceased operations in Weed, CA and Dillard, OR in 2025. Industrial customers using gas will be subject to Oregon's climate policies like the Climate Protection Program, which calls for a reduction of "90% of carbon emissions from diesel, gasoline and natural gas companies by 2050." This is a prime opportunity to support commercial customers to transition away from gas.

As the Commission considers NW Natural's proposed purchase of the pipeline, we urge you to thoughtfully decommission the pipeline and prioritize energy efficient electric alternatives. This is a critical opportunity to invest in energy resilience and cost savings for South Coast communities, while mitigating the dangers of a failing gas pipeline. Coos County deserves forward-looking solutions, rather than locking our rural communities into further fossil fuel reliance.

Sincerely,

Ashley Audycki, South Coast Coordinator, Rogue Climate
Zoe Serrano, Legislative Coordinator, Rogue Climate
Jess Grady-Benson, Organizing Director, Rogue Climate

SIERRA CLUB

January 23, 2026

Via electronic filing to puc.filingcenter@puc.oregon.gov

Oregon Public Utility Commission
201 High Street SE, Suite 100
Salem, Oregon 97301-3398

RE: Coos County Pipeline - UG 527, 528, and UM 2417

Dear Chair Tawney, and Commissioners Perkins and Power:

I am writing to voice the Sierra Club's concerns about NW Natural's proposal to purchase the Coos County Pipeline, and to use millions of ratepayer dollars to repair this aging gas infrastructure. The Commission should reject this proposal, and instead use this opportunity to explore non-pipe alternatives that will reduce emissions and build community resilience.

The Coos County Pipeline has been controversial since it was first proposed in the late 1990s, with opponents, including the Sierra Club filing multiple lawsuits citing the impacts of the project to the environment, private property and public safety. Now, as the state is working to meet its climate goals, and is increasingly pursuing building and industrial electrification, we must consider alternatives to maintaining and replacing fossil fuel infrastructure, and pursue opportunities for zonal electrification.

Governor Kotek has directed the PUC to "adopt and implement greenhouse gas reduction strategies and align their decisions, activities, and investments as appropriate to advance the five least-cost pathways identified in the Oregon Energy Strategy."[1] That includes taking "appropriate actions necessary within their existing authorities to align programs, decisions, and investments to advance the state's interest in increasing cost-effective, strategic electrification of . . . buildings, and water heating systems while also supporting affordable and reliable energy for Oregon ratepayers."[2] We encourage the Commission, pursuant to EO 25-29, to take this opportunity to eliminate the significant greenhouse gas emissions from this natural gas pipeline.

As the Coos County Pipeline only serves a little over 2,000 customers, and as there are viable alternatives to the gas use, decommissioning the pipeline offers an excellent chance to electrify one of the largest communities on the coast in Oregon, reducing harmful air pollution and greenhouse gas emissions. As NW Natural notes in its application, Coos County qualifies as an environmental justice community per ORS 756.010(5), which includes "coastal communities," "rural communities," "communities with limited infrastructure," and "communities experiencing

[1] Exec. Order 25-29, page 2, I.1.
[2] *Id.* at I.1.c.

lower incomes" in its definition of environmental justice communities. As such, it is critical that we are making investments in the Coos County community to reduce climate and air pollution, outcomes which decommissioning this pipeline would achieve.

The reports from various commenters about the extent of repairs needed,[3] combined with the past history of pipeline failures,[4] suggests careful scrutiny of the workplan is necessary to determine whether any of NW Natural's ratepayers should be responsible for this poor investment. Gas utilities in a variety of dockets have repeatedly reported facing rising construction costs. Additionally, as the Energy Strategy points out, "[s]cenarios that delayed action on energy efficiency and building electrification . . . led to higher overall costs to the economy."[5] Of course, the cost of inaction cannot be overstated.

It is important for the Commission to question whether a smaller and smaller pool of customers will use gas from this pipeline over time, as furnaces and boilers are replaced with electric versions, further driving up costs. And finally, we must question whether the larger commercial and industrial customers will remain gas customers, with the volatile gas market and impacts from the Climate Protection Program, not to mention the challenges at least one timber products company faces for reasons unrelated to energy prices. Specifically, Roseburg Forest Products has not been a stable economic partner for rural communities. In the last year alone, they have ceased operations in Weed, CA[6] and Dillard, OR,[7] decisions which have significantly impacted the stability for environmental justice communities. The instability of industrial partners does not make the economic feasibility case to invest into a pipeline that would be on the shoulders of ratepayers to cover the costs.

Coos County rate-payers and residents deserve solutions and investments that make the region more economic, climate, and energy resilient. Investments can be made into microgrid planning especially for preparing for natural disasters, expanding programs to make heat pumps, solar panels, and home weatherization materials more accessible, and workforce development programs to support projects that bring sustainable, high-paying jobs to the region.

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[3] City of North Bend comment (Jan. 16, 2026) ("significant repair demands associated with landslides and riverbank failures"); Coos Bay Public Schools' comment (Jan. 21, 2026 ("significant financial and operational challenges Coos County faces as the current owner") South Coast Development Council comment (Jan. 2026) ("pipeline faces significant risks related to landslides and riverbank instability, requiring substantial remediation and ongoing investment").

[4] Dylan Rivera, The Oregonian, *Contractor loses suit over Coos County gas pipeline* (Feb. 24, 2009) (pipeline built over "terrain that contractors described as some of the most rugged in the West;" Clean Water Act violations resulted in a $1.5 million penalty); Amy Moss Strong, The World, *Residents file pipeline suit against Coos County* (Dec. 10, 2003) ("while drilling underneath stream beds, MasTec employees caused the ground to fracture and drilling lubricants to ooze into at least five local streams").

[5] Or. Dept. of Energy, Oregon Energy Strategy Executive Summary, 3-4 (Nov. 2025), https://www.oregon.gov/energy/Data-and-Reports/Documents/Oregon-Energy-Strategy-Summary.pdf.

[6]https://www.roseburg.com/news-corporate/roseburg-consolidates-veneer-production-to-strengthen-long-term-competitiveness/

[7]https://www.roseburg.com/news-corporate/roseburg-forest-products-to-cease-hardwood-plywood-production/

Please deny NW Natural's requests to put ratepayers on the hook to repair this unnecessary pipeline and instead consider non-pipeline alternatives to build community resilience and electrify the end users in Coos County.

Thank you for your consideration.

Dylan Plummer
Acting Deputy Director, Clean Heat Campaign
The Sierra Club

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January 23, 2026

Via electronic filing to puc.filingcenter@puc.oregon.gov

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[2] *Id.* at I.1.c.

lower incomes" in its definition of environmental justice communities. As such, it is critical that we are making investments in the Coos County community to reduce climate and air pollution, outcomes which decommissioning this pipeline would achieve.

The reports from various commenters about the extent of repairs needed,[3] combined with the past history of pipeline failures,[4] suggests careful scrutiny of the workplan is necessary to determine whether any of NW Natural's ratepayers should be responsible for this poor investment. Gas utilities in a variety of dockets have repeatedly reported facing rising construction costs. Additionally, as the Energy Strategy points out, "[s]cenarios that delayed action on energy efficiency and building electrification . . . led to higher overall costs to the economy."[5] Of course, the cost of inaction cannot be overstated.

It is important for the Commission to question whether a smaller and smaller pool of customers will use gas from this pipeline over time, as furnaces and boilers are replaced with electric versions, further driving up costs. And finally, we must question whether the larger commercial and industrial customers will remain gas customers, with the volatile gas market and impacts from the Climate Protection Program, not to mention the challenges at least one timber products company faces for reasons unrelated to energy prices. Specifically, Roseburg Forest Products has not been a stable economic partner for rural communities. In the last year alone, they have ceased operations in Weed, CA[6] and Dillard, OR,[7] decisions which have significantly impacted the stability for environmental justice communities. The instability of industrial partners does not make the economic feasibility case to invest into a pipeline that would be on the shoulders of ratepayers to cover the costs.

Coos County rate-payers and residents deserve solutions and investments that make the region more economic, climate, and energy resilient. Investments can be made into microgrid planning especially for preparing for natural disasters, expanding programs to make heat pumps, solar panels, and home weatherization materials more accessible, and workforce development programs to support projects that bring sustainable, high-paying jobs to the region.

---

[3] City of North Bend comment (Jan. 16, 2026) ("significant repair demands associated with landslides and riverbank failures"); Coos Bay Public Schools' comment (Jan. 21, 2026 ("significant financial and operational challenges Coos County faces as the current owner") South Coast Development Council comment (Jan. 2026) ("pipeline faces significant risks related to landslides and riverbank instability, requiring substantial remediation and ongoing investment").

[4] Dylan Rivera, The Oregonian, *Contractor loses suit over Coos County gas pipeline* (Feb. 24, 2009) (pipeline built over "terrain that contractors described as some of the most rugged in the West;" Clean Water Act violations resulted in a $1.5 million penalty); Amy Moss Strong, The World, *Residents file pipeline suit against Coos County* (Dec. 10, 2003) ("while drilling underneath stream beds, MasTec employees caused the ground to fracture and drilling lubricants to ooze into at least five local streams").

[5] Or. Dept. of Energy, Oregon Energy Strategy Executive Summary, 3-4 (Nov. 2025), https://www.oregon.gov/energy/Data-and-Reports/Documents/Oregon-Energy-Strategy-Summary.pdf.

[6]https://www.roseburg.com/news-corporate/roseburg-consolidates-veneer-production-to-strengthen-long-term-competitiveness/

[7]https://www.roseburg.com/news-corporate/roseburg-forest-products-to-cease-hardwood-plywood-production/

Please deny NW Natural's requests to put ratepayers on the hook to repair this unnecessary pipeline and instead consider non-pipeline alternatives to build community resilience and electrify the end users in Coos County.

Thank you for your consideration.

Dylan Plummer
Acting Deputy Director, Clean Heat Campaign
The Sierra Club

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January 23, 2026

Via electronic filing to puc.filingcenter@puc.oregon.gov

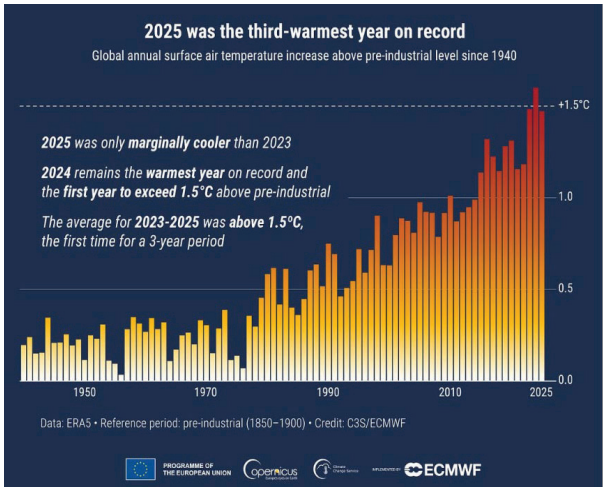
Oregon Public Utility Commission
201 High Street SE, Suite 100
Salem, Oregon 97301-3398

RE: Coos County Pipeline - UG 527, 528, and UM 2417

Dear Chair Tawney, and Commissioners Perkins and Power:

This is an unusual time in Oregon's climate policy history; we are close to standing up an entity to issue community climate investments, we are implementing rules for large buildings to decrease energy use, we are approaching a time when we will adopt rules requiring energy intensive trade exposed entities to reduce carbon emissions, and we have a brand new Energy Strategy setting out five pathways to meet our climate and energy goals. The timing for considering an alternative future for the communities served by the publicly owned Coos County pipeline is either terrible or ideal. Either way, it offers a great opportunity to assess where we are now and how we can best achieve Oregon's climate and energy goals.

NW Natural's request to cancel Schedule 160, facilitating its purchase of the county-owned pipeline for $1.00, and use deferred accounting to track the *at least* $10 million to undertake landslide prevention work, doubling down on a future locked into fossil fuel use, comes at a time of reckoning for climate action.



Credit: C3S/ECMWF The period of 2015 through 2025 has been the hottest ever recorded, with each of those eleven years being among the 11 warmest years yet.

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Are we serious about implementing an energy transition? If so, this seems like a good time to invest in an under-invested community, apply solutions that we've wanted to implement, and stop throwing good money after bad.

In considering NW Natural's vision for the future, set out in this request, we should account for the Governor's Executive Orders, the Energy Strategy, the opportunity cost of accepting the status quo, and the real opportunity presented to improve residents' lives.

I. Energy Strategy and Executive Order 25-29

Governor Kotek has directed the PUC to "adopt and implement greenhouse gas reduction strategies and align their decisions, activities, and investments as appropriate to advance the five least-cost pathways identified in the Oregon Energy Strategy."[1] That includes taking "appropriate actions necessary within their existing authorities to align programs, decisions, and investments to advance the state's interest in increasing cost-effective, strategic electrification of . . . buildings, and water heating systems while also supporting affordable and reliable energy for Oregon ratepayers."[2]

If the Commission considers this an inappropriate time or context, pursuant to EO 25-29, to eliminate GHG emissions from a natural gas pipeline delivering natural gas to 2,000 customers, it should explain why.

II. Estimated cost of the pipeline repairs versus actual cost of pipeline repairs

The reports from various commenters about the extent of repairs needed,[3] combined with the past history of pipeline failures,[4] suggests careful scrutiny of the workplan is necessary to determine whether any of NW Natural's ratepayers should be responsible for this poor

[1] Exec. Order 25-29, page 2, I.1.
[2] *Id.* at I.1.c.
[3] City of North Bend comment (Jan. 16, 2026) ("significant repair demands associated with landslides and riverbank failures"); Coos Bay Public Schools' comment (Jan. 21, 2026 ("significant financial and operational challenges Coos County faces as the current owner") South Coast Development Council comment (Jan. 2026) ("pipeline faces significant risks related to landslides and riverbank instability, requiring substantial remediation and ongoing investment").
[4] Dylan Rivera, The Oregonian, *Contractor loses suit over Coos County gas pipeline* (Feb. 24, 2009) (pipeline built over "terrain that contractors described as some of the most rugged in the West;" Clean Water Act violations resulted in a $1.5 million penalty); Amy Moss Strong, The World, *Residents file pipeline suit against Coos County* (Dec. 10, 2003) ("while drilling underneath stream beds, MasTec employees caused the ground to fracture and drilling lubricants to ooze into at least five local streams").

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investment. Gas utilities in a variety of dockets have repeatedly reported facing rising construction costs. Additionally, as the Energy Strategy points out, "[s]cenarios that delayed action on energy efficiency and building electrification . . . led to higher overall costs to the economy."[5] Of course, the cost of inaction cannot be overstated. It is important for the Commission to question whether a smaller and smaller pool of customers will use gas from this pipeline over time, as furnaces and boilers are replaced with electric versions, further driving up costs. And finally, we must question whether the larger commercial and industrial customers will remain gas customers, with the volatile gas market and impacts from the Climate Protection Program, not to mention the challenges at least one timber products company faces for reasons unrelated to energy prices. Specifically, Roseburg Forest Products has not been a stable economic partner for rural communities. In the last year alone, they have ceased operations in Weed, CA[6] and Dillard, OR,[7] decisions which have significantly impacted the stability for environmental justice communities. The instability of industrial partners does not make the economic feasibility case to invest in a pipeline that would be on the shoulders of ratepayers to cover the costs.

III. Forward-thinking solutions could improve lives and pocket books

Entities that have submitted comments in the docket are right to be concerned about what happens in the near term. Their businesses and homes rely on natural gas right now. But opportunities to bring resilience, cooling, and lower costs warrant consideration of electrification in order to future-proof the community.

For example, PacifiCorp has an obligation to provide at least 10 percent of its aggregate electrical capacity using electricity generated by small-scale renewable energy projects by 2030. At least two companies operating in the County are producing wood pellets for overseas markets.[8] Local use of this resource, in partnership with PacifiCorp, could keep limited dollars in the hands of local companies and residents while bringing resilience to the community.

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[5] Or. Dept. of Energy, Oregon Energy Strategy Executive Summary, 3-4 (Nov. 2025), https://www.oregon.gov/energy/Data-and-Reports/Documents/Oregon-Energy-Strategy-Summary.pdf.
[6] https://www.roseburg.com/news-corporate/roseburg-consolidates-veneer-production-to-strengthen-long-term-competitiveness/
[7] https://www.roseburg.com/news-corporate/roseburg-forest-products-to-cease-hardwood-plywood-production/
[8] https://forestnet.com/oregon-company-starts-up-new-wood-pellet-operations/

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Organic West Creamery relies on a boiler to operate its facility, but could consider electrification and thermal energy storage to reduce its energy needs.[9] We understand from conversations with green building sustainability managers that it is possible to electrify wood products/lumber operations, and that it is an especially good opportunity for smaller and more rural operations.

Switchbox has just developed a new nonpipeline alternatives tool[10] that, in the hands of Staff with access to the relevant information, might offer more information about the costs and benefits of decommissioning this pipeline.

Thank you for the opportunity to offer thoughts on this proposal.

Sincerely,

Carra Sahler
Director, Staff Attorney
Green Energy Institute at Lewis & Clark Law School

[9] Future CleanTech Architects, Case Study: Electrification and Thermal Energy Storage in Dairy Industry (Nov. 2025), https://fcarchitects.org/content/case-study-thermal-energy-storage-dairy-industry/.
[10] https://switchbox.shinyapps.io/npa_how_to_pay_app/

75th OREGON LEGISLATIVE ASSEMBLY--2009 Regular Session

B-Engrossed
Senate Bill 76

Ordered by the House June 3
Including Senate Amendments dated February 13 and House Amendments dated June 3

Printed pursuant to Senate Interim Rule 213.28 by order of the President of the Senate in conformance with pre-session filing rules, indicating neither advocacy nor opposition on the part of the President (at the request of Governor Theodore R. Kulongoski)

SUMMARY

The following summary is not prepared by the sponsors of the measure and is not a part of the body thereof subject to consideration by the Legislative Assembly. It is an editor's brief statement of the essential features of the measure.

Directs Public Utility Commission to determine depreciation schedules for Klamath River dams based on assumption that dams will be removed in 2020. Directs commission to allow affected public utility to recover undepreciated amounts by imposing rates and tariffs.

Directs Public Utility Commission to require affected public utility to collect surcharges from customers for purpose of recovering costs incurred by public utility for removal of Klamath River dams. Imposes limit on amounts collected as surcharges. Requires commission to hold public hearing on imposed surcharges. Provides for direct review by Supreme Court if person challenges order issued pursuant to public hearing. Provides that if commission determines that Klamath River dams will not be removed, commission may terminate collection of all or part of surcharges and direct refund of amounts collected or use of amounts collected for benefit of customers.

Directs Public Utility Commission to allow affected public utility to include in rates and tariffs costs that are prudently incurred by utility by reason of changes in operation of Klamath River dams before removal of dams, or for replacement power after dams are removed.

Declares emergency, effective on passage.

A BILL FOR AN ACT

Relating to Klamath River dams; and declaring an emergency.

Whereas the Klamath Agreement in Principle was signed November 13, 2008, by the states of Oregon and California, by the United States Department of the Interior and by PacifiCorp, and it is anticipated that a final agreement will be entered into by these and other parties; and

Whereas the Klamath Agreement in Principle states that it is the preliminary view of this state and the United States Department of the Interior that the potential benefits of the removal of dams on the Klamath River for fisheries, water and other resources outweigh the potential costs of that removal; and

Whereas it is anticipated that, subject to final analysis and confirmation by the Secretary of the Interior and review by the states of Oregon and California, the Klamath Agreement in Principle and the final agreement will together set forth a framework for action based on the preliminary view that removal of dams on the Klamath River is in the public interest; and

Whereas to facilitate the removal of the Klamath River dams, the Public Utility Commission must set rates that allow PacifiCorp to recover Oregon's fair share of PacifiCorp's undepreciated investment in the dams, to recover the funds necessary to pay additional costs that PacifiCorp may incur from changes in operation of the dams prior to removal and to pay for replacement resources following removal; and

Whereas to facilitate removal of the dams, the Public Utility Commission must establish a sur-

NOTE: Matter in **boldfaced** type in an amended section is new; matter [*italic and bracketed*] is existing law to be omitted. New sections are in **boldfaced** type.

charge to provide funds necessary to cover costs associated with removal of the dams; and

Whereas the public interest requires that the Public Utility Commission hold a hearing to determine whether the imposition of surcharges under the terms of the final agreement results in rates that are fair, just and reasonable; now, therefore,

Be It Enacted by the People of the State of Oregon:

SECTION 1. Sections 2 to 8 of this 2009 Act are added to and made a part of ORS chapter 757.

SECTION 2. Definitions. As used in sections 2 to 8 of this 2009 Act:

(1) "Agreement in principle" means the agreement signed November 13, 2008, by the states of Oregon and California, by the United States Department of the Interior and by PacifiCorp.

(2) "Allocated share" means the portion of PacifiCorp's costs assigned to this state under the interjurisdictional cost allocation methodology used by the Public Utility Commission for the purpose of establishing rates for PacifiCorp.

(3) "Customers" means the Oregon retail electricity customers of PacifiCorp.

(4) "Final agreement" means a successor agreement to the agreement in principle.

(5) "Klamath River dam" means the J.C. Boyle Dam located in Oregon, the Copco 1 Dam located in California, the Copco 2 Dam located in California or the Iron Gate Dam located in California.

SECTION 3. Recovery of investment in Klamath River dams. (1) Not more than six months after the execution of a final agreement, the Public Utility Commission shall determine a depreciation schedule under ORS 757.140 for each Klamath River dam based on the assumption that the dam will be removed in 2020. The commission may change a depreciation schedule determined under this section at any time if removal of a dam will occur during a year other than 2020.

(2) The commission shall use the depreciation schedules prepared under this section to establish rates and tariffs for the recovery of Oregon's allocated share of undepreciated amounts prudently invested by PacifiCorp in a Klamath River dam. Amounts recoverable under this section include, but are not limited to:

(a) Return of investment and return on investment;

(b) Capital improvements required by the United States or any state for continued operation of the dam until dam removal;

(c) Amounts spent by PacifiCorp in seeking relicensing of the dam before the effective date of this 2009 Act;

(d) Amounts spent by PacifiCorp for settlement of the issues of relicensing or removal of the dam; and

(e) Amounts spent by PacifiCorp for the decommissioning of the dam in anticipation of the dam's removal.

(3) If any amount specified under subsection (2) of this section has not been recovered by PacifiCorp before a dam is removed, the Public Utility Commission shall allow recovery of that amount by PacifiCorp in PacifiCorp's rates and tariffs. The commission shall allow the recovery without an amortization schedule if the impact of the recovery does not exceed one-half of one percent of PacifiCorp's annual revenue requirement. If the impact exceeds one-half of one percent of PacifiCorp's annual revenue requirement, the commission may establish an amortization schedule that limits the annual impact to one-half of one percent

of PacifiCorp's annual revenue requirement.

SECTION 4. Surcharges for funding costs of removing Klamath River dams. (1) Not more than 30 days after the execution of a final agreement, PacifiCorp must file a copy of the final agreement with the Public Utility Commission along with full and complete copies of all analyses or studies that relate to the rate-related costs, benefits and risks for customers of removing or relicensing Klamath River dams and that were reviewed by PacifiCorp during the decision-making process that led to PacifiCorp's entering into the final agreement.

(2) PacifiCorp must include with the filing made under subsection (1) of this section tariffs for the collection of two nonbypassable surcharges from its customers for the purpose of paying the costs of removing Klamath River dams as described in subsection (11) of this section. Notwithstanding the commission's findings and conclusions under subsection (4) of this section, the commission shall require PacifiCorp to begin collecting the surcharges on the date that the filing is made under subsection (1) of this section, or on January 1, 2010, whichever is later, and PacifiCorp shall continue to collect the surcharges pending a final decision on the commission's order under subsection (4) of this section. The surcharges imposed under this section shall be:

(a) A surcharge for the costs of removing the J.C. Boyle Dam; and

(b) A surcharge for the costs of removing the Copco 1 Dam, the Copco 2 Dam and the Iron Gate Dam.

(3) The surcharges imposed under this section may not exceed the amounts necessary to fund Oregon's share of the customer contribution of $200 million identified in the agreement in principle. In addition, the total amount collected in a calendar year under both surcharges may not exceed more than two percent of PacifiCorp's annual revenue requirement as determined in PacifiCorp's last case under ORS 757.210 decided by the commission before January 1, 2010.

(4) Not more than six months after a filing is made under subsection (1) of this section, the commission shall conduct a hearing under ORS 757.210 on the surcharges imposed under this section, and shall enter an order setting forth findings and conclusions as to whether the imposition of surcharges under the terms of the final agreement results in rates that are fair, just and reasonable.

(5) Notwithstanding ORS 183.482 (1), jurisdiction for judicial review of any appeal of an order entered under subsection (4) of this section is conferred on the Supreme Court, and a person seeking judicial review of the order must file a petition for review with the Supreme Court in the manner provided by ORS 183.482. ORS 183.482 (3) does not apply to an order entered under subsection (4) of this section. If a petition for review is filed, the surcharges imposed under the terms of the final agreement shall remain in effect pending a final decision on the petition, but shall be refunded if the rates resulting from the surcharges are finally determined not to be fair, just and reasonable. A petition filed under this subsection must indicate on its face that the petition is filed pursuant to this subsection.

(6) The commission may not use any commercially sensitive information provided to the commission in a filing made under subsection (1) of this section for any purpose other than determining whether the imposition of surcharges under the terms of the final agreement results in rates that are fair, just and reasonable. Notwithstanding ORS 192.410 to 192.505, the commission may not release commercially sensitive information provided to the commission under this section, and shall require any person participating in a proceeding relat-

ing to the surcharge to sign a protective order prepared by the commission before allowing the participant to obtain and use the information.

(7) The surcharges imposed under this section must be of a specified amount per kilowatt hour billed to retail customers, as determined by the commission. The amount of each surcharge shall be calculated based on a collection schedule that will fund, by December 31, 2019, Oregon's share of the customer contribution of $200 million identified in the agreement in principle. To the extent practicable, the commission shall set the surcharges so that total annual collections of the surcharges remain approximately the same during the collection period. The commission may change the collection schedule if a Klamath River dam will be removed during a year other than 2020.

(8) Except as provided in section 5 (2) of this 2009 Act, all amounts collected under the surcharges imposed under this section shall be paid into the appropriate trust account established under section 5 of this 2009 Act.

(9) If the commission determines at any time that amounts have been collected under this section in excess of those needed, or in excess of those allowed, the commission must:

(a) Direct the trustee of the appropriate trust account under section 5 of this 2009 Act to refund these excess amounts to customers or to otherwise use these amounts for the benefit of customers; or

(b) Adjust future surcharge amounts as necessary to offset the excess amounts.

(10) If one or more Klamath River dams will not be removed, the commission shall direct PacifiCorp to terminate collection of all or part of the surcharges imposed under this section. In addition, the commission shall direct the trustee of the appropriate trust account under section 5 of this 2009 Act to apply any excess balances in the accounts to Oregon's allocated share of prudently incurred costs to implement Federal Energy Regulatory Commission relicensing requirements. If any excess amounts remain in the trust accounts after that application, the Public Utility Commission shall order that the excess amounts be refunded to customers or otherwise be used for the benefit of customers in accordance with Public Utility Commission rules and policies.

(11) For the purposes of subsection (2) of this section, "the costs of removing Klamath River dams" includes costs of:

(a) Physical removal of the dams;

(b) Site remediation and restoration;

(c) Avoiding downstream impacts of dam removal;

(d) Downstream impacts of dam removal;

(e) Permits that are required for the removal;

(f) Removal and disposal of sediment, debris and other materials, if necessary; and

(g) Compliance with environmental laws.

SECTION 5. Surcharge trust accounts. (1) The Public Utility Commission shall establish a separate trust account for amounts generated by each of the two surcharges imposed under section 4 of this 2009 Act. The commission shall establish the trust accounts as interest-bearing accounts with an agency of the United States identified in the final agreement, or in a depository that is qualified under ORS 295.001 to 295.108 to receive public funds. The commission may authorize transfer of funds from one trust account to another as necessary to fund removal of the Klamath River dams.

(2) If an agreement is entered into under section 7 (2) of this 2009 Act, the parties to the

agreement may agree that a portion of the amounts collected under one surcharge may be deposited in the trust account established for amounts collected under the other surcharge.

(3) Upon request of an agency of the United States, or upon request of the designee of an agency of the United States, the commission shall require the trustee of the appropriate trust account established under this section to transfer to the agency or designee the amounts that are necessary to pay the costs of removing the Klamath River dams as described in section 4 (11) of this 2009 Act.

(4) If any amounts remain in a trust account established under this section after the trustee makes all payments necessary for the costs of removing the Klamath River dams as described in section 4 (11) of this 2009 Act, the commission shall direct the trustee of the account to refund those amounts to customers or to otherwise use the excess amounts for the benefit of customers.

SECTION 6. Recovery of other costs incurred by PacifiCorp. Pursuant to ORS 757.210, the Public Utility Commission shall allow PacifiCorp to include in its rates and tariffs this state's allocated share of any costs that are prudently incurred by PacifiCorp from changes in operation of Klamath River dams before removal of the dams, or that are prudently incurred for replacement power after the dams are removed, that are not otherwise recovered under sections 3 and 4 of this 2009 Act.

SECTION 7. Agreement to apportion costs and to establish and administer trust fund. (1) The State of Oregon may enter into an agreement with representatives of the State of California, either as part of a final agreement or by separate agreement, that establishes each state's share of the customer contribution of $200 million identified in the agreement in principle.

(2) The Public Utility Commission may enter into an agreement with representatives of the State of California to establish and administer the trust accounts authorized under section 5 of this 2009 Act and to ensure that trust account moneys are disbursed for dam removal costs that are necessary and appropriate.

SECTION 8. Disclaimers. (1) Sections 2 to 8 of this 2009 Act do not authorize the expenditure of any public moneys for removal of Klamath River dams.

(2) Sections 2 to 8 of this 2009 Act do not create a cause of action against the State of Oregon or against any of the officers, employees or agents of the state and may not be used as the basis for an assertion of liability on the part of the State of Oregon or of any officers, employees or agents of the state.

SECTION 9. The section captions used in this 2009 Act are provided only for the convenience of the reader and do not become part of the statutory law of this state or express any legislative intent in the enactment of this 2009 Act.

SECTION 10. This 2009 Act being necessary for the immediate preservation of the public peace, health and safety, an emergency is declared to exist, and this 2009 Act takes effect on its passage.

PAC/02
Hemstreet/1

KLAMATH HYDROELECTRIC SETTLEMENT AGREEMENT

February 18, 2010
as amended April 6, 2016
& November 30, 2016

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The KLAMATH HYDROELECTRIC SETTLEMENT AGREEMENT was made and entered into by and among the following entities:

Ady District Improvement Company;
American Rivers;
Bradley S. Luscombe;
California Department of Fish and Game ("CDFG");
California Natural Resources Agency ("CNRA");
California Trout;
Collins Products, LLC;
Don Johnston & Son;
Enterprise Irrigation District;
Humboldt County, California;
Institute for Fisheries Resources;
Inter-County Properties Co., which acquired title as Inter-County Title Co.;
Karuk Tribe;
Klamath Basin Improvement District;
Klamath County, Oregon;
Klamath Drainage District;
Klamath Irrigation District;
Klamath Tribes;
Klamath Water and Power Agency ("KWAPA");
Klamath Water Users Association ("KWUA");
Malin Irrigation District;
Midland District Improvement Company;
Northern California Council, Federation of Fly Fishers;
Oregon Department of Environmental Quality ("ODEQ");
Oregon Department of Fish and Wildlife ("ODFW");
Oregon Water Resources Department ("OWRD");
Pacific Coast Federation of Fishermen's Associations;
PacifiCorp;
Pioneer District Improvement Company;
Plevna District Improvement Company;
Randolph Walthall and Jane Walthall as trustees under declaration of trust dated November 28, 1995 (the "Randolph and Jane Walthall 1995 trust");
Reames Golf and Country Club;
Salmon River Restoration Council;
Shasta View Irrigation District;
Sunnyside Irrigation District;
Trout Unlimited;
Tulelake Irrigation District;
United States Department of Commerce's National Marine Fisheries Service ("NMFS");
United States Department of the Interior ("Interior");
Upper Klamath Water Users Association ("UKWUA");
Van Brimmer Ditch Company;
Westside Improvement District #4;

Winema Hunting Lodge, Inc.; and
Yurok Tribe;

This Klamath Hydroelectric Settlement Agreement, as amended, is entered into by and among the entities who sign the Settlement.

1. Introduction

1.1 Recitals

WHEREAS, the States, the United States and PacifiCorp entered into the 2008 Agreement in Principle that addressed issues pertaining to the resolution of certain litigation and other controversies in the Klamath Basin, including a path forward for possible Facilities Removal; and

WHEREAS, the 2008 AIP provided that the parties to the 2008 AIP would continue good-faith negotiations to reach a final settlement agreement in order to minimize adverse impacts of dam removal on affected communities, local property values and businesses and to specify substantive rights, obligations, procedures, timetables, agency and legislative actions, and other steps for Facilities Removal; and

WHEREAS, the other Parties to this Settlement desired to participate in the negotiations of a final settlement agreement in order to ensure that the interests of Indian tribes, environmental organizations, fishermen, water users, and local communities were addressed; and

WHEREAS, the Parties view this Settlement as an important part of the resolution of long-standing, complex, and intractable conflicts over resources in the Klamath Basin; and

WHEREAS, the 2008 AIP established a "commitment to negotiate" a settlement "based on existing information and the preliminary view of the governmental Parties (the United States, Oregon, and California) that the potential benefits for fisheries, water and other resources of removing the Facilities outweigh the potential costs, risks, liabilities or other adverse consequences of such removal"; and

WHEREAS, certain Parties believe that decommissioning and removal of the Facilities will help restore Basin natural resources, including anadromous fish, fisheries and water quality; and

WHEREAS, the Parties understand that the Project dams are currently the property of PacifiCorp, and that they are currently operated subject to applicable state and federal law and regulations. The other Parties understand that the decision before PacifiCorp is whether the decommissioning and removal of certain Facilities is appropriate and in the best interests of PacifiCorp and its customers. PacifiCorp asserts that prudent and reasonable long-term utility rates and protection from any liability for damages caused by Facilities Removal are central to its willingness to voluntarily transfer the dams and the low-carbon renewable energy they produce and to concur in the removal of the dams by the DRE; and

WHEREAS, the United States has devoted considerable funds and resources toresource enhancements, management actions, and compensation in the Klamath Basin, and various Parties believe that a broader and integrated approach is appropriate to realize Basin-wide objectives; and

WHEREAS, this Settlement contemplates a substantial non-federal contribution in support of said approach; and

WHEREAS, the Tribes and the Federal Parties agree that this Settlement advances the trust obligation of the United States to protect Basin Tribes' federally reserved fishing and water rights in the Klamath and Trinity River Basins; and

WHEREAS, in 2016, PacifiCorp, the United States, and the States signed the 2016 Agreement in Principle to signify their intent to negotiate an amended KHSA that would facilitate Facilities Removal through the existing authority of FERC under the Federal Power Act; and

WHEREAS, all of the Parties agree that this Settlement is in the public interest.

NOW, THEREFORE, the Parties agree as follows:

1.2 Purpose of Settlement

The Parties have entered into this Settlement for the purpose of resolving among them the pending FERC relicensing proceeding by establishing a process for potential Facilities Removal and operation of the Project until that time.

1.3 Parties Bound by Settlement

The Parties shall be bound by this Settlement for the term stated in Section 8.1 herein, unless terminated pursuant to Section 8.11.

1.4 Definitions

"2008 Agreement in Principle" or **"2008 AIP"** refers to the Agreement in Principle executed on November 13, 2008, by the states of Oregon and California, Interior, and PacifiCorp setting forth a framework for potential Facilities Removal.

"2016 Agreement in Principle" or **"2016 AIP"** refers to the Agreement in Principle executed on February 2, 2016, by the states of Oregon and California, Interior, the U.S. Department of Commerce, and PacifiCorp signifying their intent to negotiate an amended KHSA that would achieve Facilities Removal through the existing authority of FERC under the Federal Power Act.

"Amendment Effective Date" is defined in Section 8.2.

"Applicable Law" means general law that (1) exists outside of this Settlement, including, but not limited to a Constitution, statute, regulation, court decision, or common law, and (2) applies to obligations or activities of Parties contemplated by this Settlement. The use of this term is not intended to create a contractual obligation to comply with any law that would not otherwise apply.

"Authorizing Legislation" refers to the statutes enacted by the Oregon and California Legislatures, respectively, to authorize and implement certain aspects of this Settlement, if necessary.

"**CEQA**" refers to the California Environmental Quality Act, Cal. Pub. Res. Code § 21000 *et seq*.

"**CWA**" refers to the Clean Water Act, 33 U.S.C. § 1251 *et seq.*

"Coordination Process" for the Studies Supporting the Secretarial Determination means the process contained in Appendix A by which the United States will obtain input and assistance from the Parties to this Settlement, as governed by Applicable Law, regarding the studies and environmental compliance actions needed to inform and support the Secretarial Determination.

"**Counties**" refers to the counties that sign this Settlement.

"**Dam Removal Entity**" or "**DRE**" is the Klamath River Renewal Corporation, which will be the entity responsible for Facilities Removal under this Settlement.

"**Decommissioning**" means PacifiCorp's physical removal from a facility of any equipment and personal property that PacifiCorp determines has salvage value, and physical disconnection of the facility from PacifiCorp's transmission grid.

"**Definite Plan**" means a plan and timetable for Facilities Removal submitted by the DRE or any of its contractors or assigns under Section 7.2.1.

"**Detailed Plan**" means the plan dated July 2012 that includes elements described in Section 7.2.2.

"Dispute Resolution Procedures" means the procedures established by Section 8.6.

"Due Diligence" means a Party's taking all reasonable steps to implement its obligations under this Settlement.

"**Effective Date**" is defined in Section 8.2.

"**EPAct**" refers to the Energy Policy Act of 2005, Section 241, codified at 16 U.S.C. § 823d and amendments to 16 U.S.C. §§ 797(e) and 811.

"ESA" refers to the federal Endangered Species Act, 16 U.S.C. §§ 1531 *et seq*.

"**Facilities**" or "**Facility**" means the following specific hydropower facilities within the jurisdictional boundary of FERC Project No. 2082: Iron Gate Dam, Copco No. 1 Dam, Copco No. 2 Dam, J.C. Boyle Dam, and appurtenant works currently licensed to PacifiCorp.

"**Facilities Removal**" means physical removal of all or part of each of the Facilities to achieve at a minimum a free-flowing condition and volitional fish passage, site remediation and restoration, including previously inundated lands, measures to avoid or minimize adverse downstream impacts, and all associated permitting for such actions.

"**Federal Parties**" refers to Interior, including the component agencies and bureaus of Interior, and the NMFS.

"**FERC**" refers to the Federal Energy Regulatory Commission.

"**Interim Conservation Plan**" or "**ICP**" refers to the plan developed by PacifiCorp through technical discussions with NMFS and the U.S. Fish and Wildlife Service ("USFWS") regarding voluntary interim measures for the enhancement of coho salmon and suckers listed under the ESA, filed with FERC on November 25, 2008, or such plan as subsequently modified.

"**Interim Measures**" refers to those measures described in Appendices C and D to this Settlement.

"**Interim Period**" refers to the period between the Effective Date and Decommissioning.

"**Keno facility**" means Keno Dam, lands underlying Keno Dam, appurtenant works and PacifiCorp-owned property described as Klamath County Map Tax Lot R-3907-03600-00200-000 located in Klamath County, Oregon.

"Klamath Hydroelectric Settlement Agreement" or **"KHSA"** means the Klamath Hydroelectric Settlement Agreement executed February 18, 2010.

"**Meet and Confer**" procedures mean the procedures established by Section 8.7 of this Settlement.

"**NEPA**" refers to the National Environmental Policy Act, 42 U.S.C. §§ 4321 *et seq.*

"**Nominal dollars**" means dollars that are not adjusted for inflation at the time they are collected.

"**Non-bypassable surcharge**" means a monetary surcharge authorized by the appropriate state utility commission through a tariff schedule that applies to all retail customers who rely on PacifiCorp's transmission and distribution system for the delivery of electricity.

"Notice" means written notice pursuant to the requirements and procedures of Section 8.5.

"**Oregon Surcharge Act**" is defined in Section 2.2.

"**PacifiCorp's Economic Analysis**" means the primary economic analysis prepared by PacifiCorp and relied upon by PacifiCorp to compare the present value revenue requirement impact of the KHSA against the present value revenue requirement of relicensing of the Facilities under defined prescriptions generally based on the FERC Final Environmental Impact Statement dated November 2007, which analysis PacifiCorp filed with the Public Utility Commission of Oregon ("Oregon PUC") pursuant to Section 4(1) of the Oregon Surcharge Act and with the California Public Utilities Commission ("California PUC") in accordance with Section 4 of the KHSA. This analysis was used to compare the relative cost of relicensing with the relative cost of the KHSA.

"**Parties**" or "**Party**" means the signatories to this Amended KHSA collectively or a signatory individually.

"**Project**" refers to the Klamath Hydroelectric Project as licensed by FERC under Project No. 2082.

"Public Agency Party" means each Tribe, the Federal Parties, the agencies of each of the States, the Counties, and each other Party that is a public agency established under Applicable Law.

"Regulatory Approval" means each permit or other approval under a statute or regulation necessary or appropriate to implement any of the obligations or activities of Parties contemplated under this Settlement.

"Regulatory Obligation" means each of those obligations or activities of Parties contemplated by this Settlement that are subject to Regulatory Approval and, upon such approval, are enforceable under regulatory authority.

"**Secretarial Determination**" means the determination contemplated in Section 3.3 of the KHSA.

"**Secretary**" refers to the Secretary of the Interior.

"**Services**" means the National Marine Fisheries Service and the U.S. Fish and Wildlife Service.

"**Settlement**" means the entirety of the KHSA and Appendices A through L, as amended and applicable. "Settlement" does not include Exhibits 1 through 4, which are related documents attached for informational purposes.

"**States**" refers to the State of Oregon by and through the Oregon Department of Fish and Wildlife, Oregon Department of Environmental Quality, and Oregon Water Resources

Department, and the State of California by and through the California Department of Fish and Wildlife ("CDFW") and the California Natural Resources Agency.

"**State Cost Cap**" means the collective maximum monetary contribution from the states of California and Oregon as described in Section 4.1.3 of this Settlement.

"Timely" or **"Timeliness"** means performance of an obligation by the deadline established in the applicable provision of this Settlement or otherwise in a manner reasonably calculated to achieve the bargained-for benefits of this Settlement.

"**Tribes**" means the Yurok Tribe, the Karuk Tribe, the Hoopa Valley Tribe, and the Klamath Tribes, so long as such tribe is a signatory to the Settlement.

"**Value to Customers**" means potential cost reductions described in Section 7.3.8. These cost reductions would (1) decrease the Customer Contribution defined in Section 4.1.1.C, (2) decrease the costs of ongoing operations, or (3) decrease the costs of replacement power, as compared against the assumptions contained in PacifiCorp's Economic Analysis.

1.5 Compliance with Legal Responsibilities

In the implementation of this Settlement, Public Agency Parties shall comply with Applicable Law, including but not limited to the Authorizing Legislation, NEPA, ESA, CWA, the Wild and Scenic Rivers Act, and CEQA.

1.6 Reservations

1.6.1 Generally

Nothing in this Settlement is intended or shall be construed to affect or limit the authority or obligation of any Party to fulfill its constitutional, statutory, and regulatory responsibilities or comply with any judicial decision. Nothing in this Settlement shall be interpreted to require the Federal Parties, the States, or any other Party to implement any action which is not authorized by Applicable Law or where sufficient funds have not been appropriated for that purpose by Congress or the States. The Parties expressly reserve all rights not granted, recognized, or relinquished in this Settlement.

1.6.2 Reservations Regarding Federal Appropriations

All actions required of the Federal Parties in implementing this Settlement are subject to appropriations for that purpose by Congress. Nothing in this Settlement shall be interpreted as or constitute a commitment or requirement that any Federal agency obligate or pay funds in violation of the Anti-Deficiency Act, 31 U.S.C. § 1341, or other Applicable Law. Nothing in this Settlement is intended or shall be construed to commit a federal official to expend federal funds not appropriated

for that purpose by Congress. Nothing in this Settlement is intended to or shall be construed to require any official of the executive branch to seek or request appropriations from Congress to implement any provision of this Settlement.

1.6.3 Availability of Public Funds

Funding by any Public Agency Party under this Settlement is subject to the requirements of Applicable Law. Nothing in this Settlement is intended or shall be construed to require the obligation, appropriation, or expenditure of any funds by the States or a Public Agency Party except as otherwise permitted by Applicable Law.

1.6.4 Reservations Regarding Legislative Proposals

Nothing in this Settlement shall be deemed to limit the authority of the executive branch of the United States government to make recommendations to Congress on any particular proposed legislation.

1.6.5 Reservations Regarding Regulations

Nothing in this Settlement is intended or shall be construed to deprive any public official of the authority to revise, amend, or promulgate regulations.

1.6.6 No Pre-Decisional Commitment

Nothing in this Settlement is intended or shall be construed to be a pre-decisional commitment of funds or resources by a Public Agency Party. Nothing in this Settlement is intended or shall be construed to predetermine the outcome of any Regulatory Approval or other action by a Public Agency Party necessary under Applicable Law in order to implement this Settlement.

1.6.7 No Waiver of Sovereign Immunity

Nothing in this Settlement is intended or shall be construed as a waiver of sovereign immunity by the United States, the State of Oregon, the State of California, any other Public Agency Party, or the Tribes. This Settlement does not obligate the United States or any Federal Party to affirmatively support this Settlement regarding any state or local legislative, administrative, or judicial action before a state administrative agency or court.

1.6.8 No Argument, Admission, or Precedent

This Settlement shall not be offered for or against a Party as argument, admission, or precedent regarding any issue of fact or law in any mediation, arbitration, litigation, or other administrative or legal proceeding, except that this Settlement may be used in any future proceeding to interpret or enforce the terms of this

Settlement, consistent with Applicable Law. This Settlement may also be used by any Party in litigation by or against non-Parties to implement or defend this Settlement. This section shall survive any termination of this Settlement.

1.6.9 Protection of Interests

Each Party may, in a manner consistent with this Settlement, protect, defend, and discharge its interests and duties in any administrative, regulatory, legislative or judicial proceeding, including but not limited to the Secretarial Determination, FERC relicensing process, CWA 401 proceedings, or other proceedings related to potential Project relicensing, surrender, or Facilities Removal.

1.7 Trinity River

The Parties intend that this Settlement shall not adversely affect the Trinity River Restoration Program.

To reach that conclusion, the Tribes reaffirm and rely upon their view of the existing fishery restoration goals and principles for the Trinity River Fishery Restoration Program, as follows:

A. Restoration of the Trinity River fish populations to pre-Trinity Dam construction levels;

B. Fishery restoration shall be measured not only by returning anadromous fish spawners but also by the ability of dependent tribal and non-tribal fishers to participate fully in the benefits of restoration through meaningful subsistence and commercial harvest opportunities;

C. An appropriate balance between stocks of natural and hatchery origins shall be maintained to minimize negative interactions upon naturally produced fish by hatchery mitigation releases;

D. A collaborative working relationship between federal agencies and the above mentioned Tribes;

E. Portions of federal activities that are associated with fishery restoration programs are Indian Programs for the purposes of the Indian Self-Determination Act; and

F. The Tribes support full funding implementation of the Trinity River Record of Decision from funding sources outside of this Settlement.

Nothing in this section binds any Party to any particular interpretation of the law or requires any Party to take particular actions, including performance of Interim Measures, or excuses any action otherwise required by Applicable Law or this Settlement.

1.8 Tribal Water Rights

This Settlement does not waive or in any way limit any treaty right, federally reserved right, or other right of the Tribes, or any federally recognized tribe, including any water or fishing right.

1.9 Klamath Basin Agreement

The States, the Federal Parties, and other entities are concurrently entering into the 2016 Klamath Power and Facilities Agreement. Each Party, other than PacifiCorp, shall support and defend the 2016 Klamath Power and Facilities Agreement, in its current form as of April 6, 2016, and its objectives in each applicable venue or forum in which it participates, including any administrative or judicial action. For purposes of this Section 1.9 only, the terms "support and defend" mean that the Party will advocate for the 2016 Klamath Power and Facilities Agreement or refrain from taking any action or making any statement in opposition to the 2016 Klamath Power and Facilities Agreement. More broadly, the Parties are committed to engage in good faith efforts to develop and enter into a subsequent agreement or agreements pertaining to other water, fisheries, land, agriculture, refuge and economic sustainability issues in the Klamath Basin with the goal to complete such agreement or agreements within the next year.

2. Implementation of Settlement

2.1 General Duty to Support Implementation

The Parties shall fully support this Settlement and its implementation. The form, manner, and timing of each Party's support are reserved to the discretion of each Party. Each Party agrees to refrain from any action that does not support or further cooperative efforts in support of the goals of this Settlement and its effective implementation.

2.1.1 Legislation

A. The Parties understand and agree that federal legislation is not necessary to carry out this Settlement.

B. Within 60 days of the Amendment Effective Date, the CDFW will provide draft California legislation to the Parties regarding a limited authorization for incidental take of Lost River Suckers, Shortnose Sucker, Golden Eagles, southern Bald Eagles, Greater Sandhill Cranes, or American Peregrine Falcon contingent upon the fulfillment of certain conditions, if such authorization is necessary for implementation of this Settlement. After reasonable opportunity for Parties to provide comments on the draft legislation, the State of California shall Timely recommend the legislation.

2.1.2 Regulatory Approvals

Subject to Sections 1.6.1, 2.1, and 7.1.5, each Party shall support the application for and granting of Regulatory Approvals consistent with this Settlement. The preceding sentence shall not apply to the Public Agency Party exercising the regulatory approval or to a Public Agency Party not participating in the proceeding.

2.1.3 Defense of Settlement

If an administrative or judicial action is brought against any Party to challenge the validity of this Settlement or its implementation consistent with the Settlement, each other Party shall endeavor to intervene or otherwise participate in such action, subject to its discretion, necessary funding, and Section 1.6. Any such participating Party will defend the Settlement. The form of such defense, including what litigation positions to support or recommend in such action, shall be left to the discretion of each participating Party in the action.

Each Party may comment on the consistency of any plan, other document, or data arising during the implementation of this Settlement and not otherwise set forth in an Appendix or Exhibit to this Settlement. The Parties acknowledge that their comments may conflict due to differing good-faith interpretations of the applicable obligations under this Settlement.

2.1.4 Obligation to Implement

A. General

Each Party shall implement each of its obligations under this Settlement in good faith and with Due Diligence. Any obligation identified as an obligation of all of the Parties does not obligate any individual Party to take any action itself or itself make any specific commitment other than to participate in the applicable procedures.

B. Cooperation Among the Parties

Each Party shall cooperate in the implementation of this Settlement. A Party shall not act in a manner that results in an action or requirement that is inconsistent with the Settlement unless necessary to comply with statutory, regulatory, or other legal responsibility.

C. Covenant Not to Sue with Respect to Permitting and Performance of Definite Plan

(1) No Party shall directly or indirectly through other entities oppose the DRE's securing all permits and entering all contracts necessary

for Facilities Removal consistent with the Definite Plan or any Regulatory Approval, provided this clause does not apply to a Public Agency Party exercising a Regulatory Approval;

(2) After transfer of the Facilities to the DRE, each Party covenants not to sue any other Party for monetary or non-monetary relief for harm arising from removal of any of the Facilities, provided this covenant does not apply to claims against the DRE arising from the negligence, recklessness, or willful misconduct of the DRE or any of its contractors, subcontractors, or assigns, or from the actions or omissions of the DRE or any of its contractors, subcontractors, or assigns inconsistent with the Definite Plan or in violation of a Regulatory Approval. This provision does not apply to rights under the indemnifications established in Section 7.1.3 or the States' agreements with the DRE required in Section 4.12.

2.1.5 Timeliness

Exhibit 4 describes the sequence of performance of specific obligations necessary to achieve the bargained-for benefits of this Settlement. Exhibit 4 is subject to change and modification as needed and is provided for guidance only. The Parties shall undertake to implement this Settlement in a manner consistent with this sequence. If any Party requires more time than permitted by this Settlement to perform an obligation, that Party shall provide Notice to other Parties 30 days before the applicable deadline, unless the applicable provision in this Settlement establishes a different period. The Notice shall explain: (1) the obligation that the Party is attempting to perform; (2) the reason that performance is or may be delayed; and (3) the steps the Party has taken or proposes to take to Timely complete performance.

2.1.6 Force Majeure

A. Definition of Force Majeure

The term "Force Majeure" means any event reasonably beyond a Party's control that prevents or materially interferes with the performance of an obligation of that Party, that could not be avoided with the exercise of due care, and that occurs without the fault or negligence of that Party. Force Majeure events may be unforeseen, foreseen, foreseeable, or unforeseeable, including without limitation: natural events; labor or civil disruption; breakdown or failure of Project works not caused by failure to properly design, construct, operate, or maintain; or new regulations or laws that are applicable to the Project (other than the Authorizing Legislation). Force Majeure is presumed not to include normal inclement weather, which presumption can be overcome by a preponderance of the evidence provided by the non-performing Party.

B. Suspension of Obligation

During a Force Majeure event, and except as otherwise provided in this Settlement, a Party shall be relieved of any specific obligation directly precluded by the event, as well as those other obligations performance of which is materially impaired, but only for the duration of such event. The non-performing Party bears the burden of proving by a preponderance of the evidence the existence of Force Majeure, including the absence of negligence and fault.

C. Remedies

If a Force Majeure event occurs, and except as otherwise provided in this Settlement:

(1) A Party that believes it is excused from performance pursuant to Section 2.1.6.B shall provide Notice within 10 days of the onset of the event. Such Notice shall describe the occurrence, nature, and expected duration of such event and describe the steps the Party has taken or proposes to be taken to prevent or minimize the interference with the performance of any affected obligation under this Settlement;

(2) A Party shall thereafter provide periodic Notice to the other Parties of the efforts to address and resolve a Force Majeure event; and

(3) If any other Party disputes the Party's claim of a Force Majeure event, or the adequacy of the efforts to address and resolve such event, such Party shall initiate the Dispute Resolution Procedures stated in Section 8.6.

2.2 Ratemaking Legislation and Proceedings

Each Party shall support implementation of the Oregon Surcharge Act enacted as Senate Bill 76, 2009 Or. Session Laws Chapter 690 in 2009 and authorizing the collection of a customer surcharge for the costs of Facilities Removal, which was codified as ORS 757.732 through 757.744. The Oregon Surcharge Act as codified is attached to this Settlement as Appendix F.

The Parties understand and agree that the costs of Facilities Removal shall be funded as specified in Section 4 of this Settlement. The Parties further understand and agree that funds allocated for Facilities Removal shall be managed and disbursed as specified in Section 4 of this Settlement. In the event that (1) the California Legislature does not adopt legislation by the time of the Secretarial Determination to place a ballot measure before California voters that contains a provision to fund up to $250,000,000 (in nominal dollars) of the costs of Facilities Removal, or (2) the California voters do not adopt such

ballot measure by the time of the Secretarial Determination, or (3) the California PUC does not adopt a California Klamath Surcharge, as defined herein and specified in Section 4, or (4) the Oregon PUC does not adopt an Oregon Klamath Surcharge, as defined in the Oregon Surcharge Act and specified herein, the Parties shall Meet and Confer to attempt, in good faith, to identify substitute funding and/or other alternatives to cover the costs of Facilities Removal.

2.3 Project Water Rights; Klamath Basin Adjudication

2.3.1 Project Water Rights

PacifiCorp's Oregon water rights will be processed and adjusted in accordance with the principles of Oregon law and the *Water Rights Agreement between PacifiCorp and the State of Oregon* attached to this Settlement as Exhibit 1.

2.3.2 Klamath Basin Adjudication

The Parties support the efforts by PacifiCorp, the Klamath Tribes, Bureau of Indian Affairs, and OWRD to develop a Klamath Basin Adjudication ("KBA") Settlement Agreement of cases 282 and 286 in the KBA.

2.4 Lease of State-Owned Beds and Banks

Within 60 days of the Effective Date, PacifiCorp shall apply to the Oregon Department of State Lands in accordance with state law for leases authorizing occupancy of submerged and submersible lands by the J.C. Boyle Dam, J.C. Boyle Powerhouse, and Keno Dam. No Party shall be deemed to have admitted, adjudicated, or otherwise agreed to the State of Oregon's claim to ownership of submerged and submersible lands by virtue of this Settlement.

3. Secretarial Designation and Statement of Support

3.1 Statement of Support

In cooperation with the Secretary of Commerce and other federal agencies as appropriate, the Secretary may make an affirmative statement of support for Facilities Removal if, in the Secretary's judgment, Facilities Removal (1) will advance restoration of the salmonid fisheries of the Klamath Basin, and (2) is in the public interest, which includes but is not limited to consideration of potential impacts on affected local communities and Tribes.

3.2 Secretarial Designation

The Secretary, through execution of Amendment No. 1, agrees that the DRE will act as the entity with authority under ORS 757.738(3) to request transfer of funds held in the appropriate trust account established under ORS 757.738. The DRE, its assigns, or successors, shall expend funds in the amounts necessary and as consistent with the Settlement to pay "the costs of removing the Klamath River dams" as that phrase is used in ORS 757.736(11).

successor, in accordance with a funding agreement as specified in Section 4.12.2, in the amounts necessary to pay "the costs of removing the Klamath River dams" as that phrase is used in ORS 757.736(11).

4. Costs

4.1 Funds for the Purpose of Facilities Removal

The Parties agree to pursue arrangements for the creation of the funding sources described below for the purpose of Facilities Removal.

4.1.1 The Customer Contribution

A. Within 30 days of the Effective Date, PacifiCorp shall request that the Oregon PUC, pursuant to the Oregon Surcharge Act, establish two non-bypassable customer surcharges, the Oregon J.C. Boyle Dam Surcharge and the Oregon Copco I and II/Iron Gate Dams Surcharge (together, the "Oregon Klamath Surcharges"), for PacifiCorp's Oregon customers to generate funds for the purpose of Facilities Removal. PacifiCorp shall request that the Oregon PUC set the Oregon Klamath Surcharges so that to the extent practicable the total annual collections of the surcharges remain approximately the same during the collection period.

B. Within 30 days of the Effective Date, PacifiCorp shall request that the California PUC establish a non-bypassable customer surcharge (the "California Klamath Surcharge") for PacifiCorp's California customers to generate funds for the purpose of Facilities Removal. PacifiCorp shall request that the California PUC establish the California Klamath Surcharge so that it will collect an approximately equal amount each year that it is to be collected. PacifiCorp shall request that such surcharge assigns responsibility among the customer classes in an equitable manner. PacifiCorp shall also request that the California PUC set the California Klamath Surcharge so that it at no time exceeds two percent of the revenue requirements set by the California PUC for PacifiCorp as of January 1, 2010.

C. The Parties agree that the total amount of funds to be collected pursuant to the Oregon Klamath Surcharges and the California Klamath Surcharge shall not exceed $200,000,000 (in nominal dollars); these funds shall be referred to as the "Customer Contribution."

D. PacifiCorp shall request that the Oregon PUC establish a surcharge so that the amount collected under the Oregon Klamath Surcharges is 92% (a maximum of approximately $184,000,000) of the total

Customer Contribution, and with 75% of the total Oregon Klamath Surcharges amount collected through the Oregon Copco I and II/Iron Gate Dams Surcharge and 25% collected through the Oregon J.C. Boyle Dam Surcharge.

E. PacifiCorp shall request that the California PUC establish a surcharge so that the amount collected under the California Klamath Surcharge is 8% (a maximum of approximately $16,000,000) of the Total Customer Contribution. The trustee of the California Klamath Surcharge shall apply 75% of the total California Klamath Surcharge amount collected to the California Copco I and II/Iron Gate Dams Trust Account and 25% of the total California Klamath Surcharge amount collected to the California J.C. Boyle Dam Trust Account.

F. PacifiCorp shall collect and remit the surcharges collected pursuant to this section to the trustee(s) described in Section 4.2, below, to be deposited into the appropriate California Klamath Trust Accounts and Oregon Klamath Trust Accounts.

G. Consistent with Section 2.1 of this Settlement, each non-Federal Party shall support the California Klamath Surcharge and the Oregon Klamath Surcharges in the proceedings conducted by the California PUC and the Oregon PUC, respectively, to the extent the proposed Surcharges are consistent with this Settlement.

4.1.2 The California Bond Funding

A. The California Legislature has approved a general obligation bond ("Bond Measure") containing a provision authorizing the issuance of bonds for the amount necessary to fund the difference between the Customer Contribution and the actual cost to complete Facilities Removal, which bond funding in any event shall not exceed $250,000,000 (in nominal dollars). The bond language is set forth in Appendix G-1. At its sole discretion, the State of California may also consider other appropriate financing mechanisms to assist in funding the difference between the Customer Contribution and the actual cost of complete Facilities Removal, not to exceed $250,000,000 (in nominal dollars).

B. Consistent with Applicable Law and Section 2.1, each non-federal Party shall support the Klamath bond language in Appendix G-1; provided that nothing in this Settlement is intended or shall be construed to require a Party to support a Bond Measure that includes authorizations unrelated to the implementation of this Settlement.

4.1.3 State Cost Cap

The Customer Contribution and the California Bond Funding shall be the total state contribution and shall be referred to together as the "State Cost Cap."

4.2 Establishment and Management of Trust Accounts and California Bond Funding

4.2.1 The Oregon Klamath Trust Accounts

A. In accordance with the Oregon Surcharge Act, the Oregon PUC will establish two interest-bearing accounts where funds collected by PacifiCorp pursuant to the Oregon Klamath Surcharges shall be deposited until needed for Facilities Removal purposes. The Oregon J.C. Boyle Dam Account shall be established to hold funds collected pursuant to the Oregon J.C. Boyle Dam Surcharge. The Oregon Copco I and II/Iron Gate Dams Account shall be established to hold funds collected pursuant to the Oregon Copco I and II/Iron Gate Dams Surcharge. The Oregon J.C. Boyle Dam Account and the Oregon Copco I and II/Iron Gate Dams Account may be referred to together as the "Oregon Klamath Trust Accounts."

B. In accordance with the Oregon Surcharge Act, the Oregon PUC will select a trustee to manage the Oregon Klamath Trust Accounts. The Parties may recommend a trustee for consideration by the Oregon PUC.

4.2.2 The California Klamath Trust Accounts

A. Upon execution of this Settlement, California shall request, and each non-Federal Party shall support the request, that the California PUC establish two interest-bearing trust accounts where funds collected by PacifiCorp pursuant to the California Klamath Surcharge for the purpose of Facilities Removal shall be deposited until needed for Facilities Removal purposes. The non-Federal Parties shall also request that California and the California PUC establish the trust accounts in a manner that ensures that the surcharge funds will not be taxable revenues to PacifiCorp. The California J.C. Boyle Dam Trust Account shall be established to hold 25% of the funds collected pursuant to the California Klamath Surcharge. The California Copco I and II/Iron Gate Dams Trust Account shall be established to hold 75% of the funds collected pursuant to the California Klamath Surcharge. The California J.C. Boyle Dam Trust Account and the California Copco I and II/Iron Gate Dams Trust Account may be referred to together as the "California Klamath Trust Accounts."

B. California shall request, and each non-Federal Party shall support the request, that the California PUC select a trustee to accept surcharge

funds from PacifiCorp and manage the California Klamath Trust Accounts. The Parties may recommend a trustee for consideration by the California PUC.

4.2.3 The California Bond Funding

In the event that the Bond Measure is placed on the ballot and approved by voters, bond funds available from the Bond Measure shall be managed pursuant to California bond law; however, the State of California agrees that, to the extent permitted by law, the California Bond Funding shall be managed and disbursed in a manner consistent with and complementary to the management and disbursement of the Customer Contribution.

4.2.4 Management of the Trust Accounts

A. Within six months of the Effective Date, the States in consultation with the Federal Parties shall prepare draft trustee instructions for submission to the respective PUCs. The States shall then request that the California PUC or another designated agency of the State of California, and the Oregon PUC work cooperatively to prepare joint instructions to the trustee(s) of the Oregon Klamath Trust Accounts and California Klamath Trust Accounts, consistent with the draft instructions, as to the following:

(1) Whether and when to disburse funds from the Oregon Klamath Trust Accounts and California Klamath Trust Accounts to the DRE;

(2) The methodology to be used by the trustee(s) to determine which account or accounts to draw funds from for the purpose of disbursing funds to the DRE;

(3) A protocol for the trustee(s) to use to ensure that the management of the Customer Contribution is consistent with and complementary to the management of the California Bond Funding;

(4) Disbursement of funds under the circumstances described in Section 4.4 below;

(5) A protocol for reallocating between Trust Accounts monies that have already been deposited into the Trust Accounts, to be used by the trustees, at the request of the States, for removal of specific facilities; and

(6) If the trustee is a federal agency, provisions ensuring that Trust Account monies are not used for any other purpose than Facilities Removal consistent with the trustee instructions and do not become part of any federal agency's or bureau's budget.

B. As necessary, the States, in consultation with PacifiCorp and the DRE, will prepare draft trustee instructions revised as appropriate and request that the California PUC or another designated agency of the state of California, and the Oregon PUC work cooperatively to prepare revised joint instructions to the trustee(s) of the Oregon Klamath Trust Accounts and California Klamath Trust Accounts consistent with the draft revised instructions. The States and PacifiCorp will take such other actions as may be reasonably necessary to facilitate the distribution of the Customer Contribution.

4.3 Adjustment to Surcharges

As appropriate, the States shall consult with each other, PacifiCorp, and the Federal Parties regarding adjustments to the California Klamath Surcharge or Oregon Klamath Surcharges necessitated by or appropriate considering the circumstances. Following such consultation, PacifiCorp will request that the California PUC and Oregon PUC adjust the Klamath Surcharges to be consistent with the recommendations developed through the consultation. Any adjustment shall not alter the maximum level of the Customer Contribution or State Cost Cap.

4.4 Disposition of Unnecessary or Unused Funds from the Oregon and/or California Klamath Trust Accounts

4.4.1 If, as described in Section 4(5) of the Oregon Surcharge Act, the Oregon Klamath Surcharges are finally determined to result in rates that are not fair, just, and reasonable, the surcharges shall be refunded to customers in accordance with the Oregon Surcharge Act and the trustee instructions.

4.4.2 In the event that the Oregon PUC finds that the Oregon Klamath Trust Accounts contain funds in excess of actual costs necessary for Facilities Removal, those excess amounts shall be refunded to customers or otherwise used for the benefit of customers as set forth in Section 4(9) of the Oregon Surcharge Act and the trustee instructions.

4.4.3 In the event that, following Facilities Removal, the trustee of the California Klamath Trust Account determines that the California Klamath Trust Account contains funds in excess of actual costs necessary for Facilities Removal, the non-Federal Parties shall request that the California PUC order those excess amounts to be refunded to customers or otherwise used for the benefit of customers.

4.4.4 If, as a result of the termination of this Settlement, or other cause, one or more Project dams will not be removed:

A. All or part of the Oregon Klamath Surcharges shall be terminated and the Oregon Klamath Trust Accounts disposed as set forth in Section 4(10) of the Oregon Surcharge Act and the trustee instructions; and

B. PacifiCorp shall request that the California PUC direct PacifiCorp to terminate all or part of the surcharge, that the California PUC direct the trustee to apply any excess balances in the California Klamath Trust Account to California's allocated share of prudently incurred costs to implement FERC relicensing requirements, and that, if any excess amount remains in the trust accounts after that application, that the California PUC order that the excess amounts be refunded to customers or otherwise be used for the benefit of customers.

4.5 Recovery of Net Investment in Facilities

4.5.1 Consistent with Section 3 of the Oregon Surcharge Act, PacifiCorp shall request, and each non-Federal Party shall support the request, that the Oregon PUC allow recovery of PacifiCorp's net investment in the Facilities.

4.5.2 PacifiCorp shall request, and each non-Federal Party shall support the request, that the California PUC conduct one or more proceedings to implement the following:

A. That the California PUC determine a depreciation schedule for each Facility based on the assumption that the Facility will be removed in 2020, and change that depreciation schedule at any time if removal of the Facility will occur in a year other than 2020; and

B. That the California PUC use the depreciation schedules adopted consistent with Section 4.5.2.A above to establish rates and tariffs for the recovery of California's allocated share of undepreciated amounts prudently invested by PacifiCorp in the Facilities, with amounts recoverable including but not limited to:

(1) Return on investment and return of investment;

(2) Capital improvements required by the Federal Parties or any agency of the United States or any agency of the States for the continued operation of the Facility until Facility removal;

(3) Amounts spent by PacifiCorp in seeking relicensing of the Project before the Effective Date of this Settlement;

(4) Amounts spent by PacifiCorp for settlement of issues relating to relicensing or removal of the Facilities; and

(5) Amounts spent by PacifiCorp for the Decommissioning of the Facilities in anticipation of Facilities Removal.

C. If any amount has not been recovered by PacifiCorp before a Facility is removed, PacifiCorp shall request, and each non-Federal Party shall support the request, that the California PUC allow recovery of that amount by PacifiCorp in PacifiCorp's rates and tariffs.

4.5.3 Rates and tariffs proposed pursuant to this Section 4.5 shall be separate from, and shall not diminish the funds collected by, the Oregon and California Klamath Surcharges.

4.6 Recovery of Costs of Ongoing Operations and Replacement Power

4.6.1 Consistent with Section 6 of the Oregon Surcharge Act, PacifiCorp shall request, and each non-Federal Party shall support the request, that the Oregon PUC allow recovery of other costs incurred by PacifiCorp.

4.6.2 Subject to Section 2.1.2, each non-Federal Party shall support PacifiCorp's request to the California PUC for PacifiCorp to include in rates and tariffs California's allocated share of any costs that are prudently incurred by PacifiCorp from changes in operation of Facilities, including reductions to generation from the Facilities before removal of the Facilities and for replacement power after the dams are removed.

4.6.3 Rates and tariffs proposed pursuant to this Section 4.6 shall be separate from, and shall not diminish the funds collected by, the Oregon and California Klamath Surcharges.

4.7 Treatment of Costs Related to Future Portfolio Standards and Climate Change Legislation

The Parties agree to Meet and Confer at PacifiCorp's request regarding provisions to address potential customer impacts from renewable portfolio standards and climate change emissions requirements.

4.8 Acknowledgment of Independence of Oregon PUC and California PUC

The Parties acknowledge that the Oregon PUC and California PUC each is a separate state agency that is not bound by this Settlement. Nothing in this Settlement expands,

limits, or otherwise affects any authority of the respective commissions regarding the customer surcharges and trust accounts, recovery of net investment, or recovery of costs of ongoing operations or replacement power. Because the Parties cannot provide assurance that either commission will decide to or be allowed to implement any of the provisions for funding Facilities Removal, failure of a commission to do so is not a breach of this Settlement by any Party.

4.9 Consultation

Before filing the requests to the California PUC and Oregon PUC described in Sections 4.5 and 4.6, above, PacifiCorp shall undertake to consult with the Parties, pursuant to a confidentiality agreement among the Parties or a protective order issued by the relevant PUC, so that the requested rates can be explained and the basis for such rates can be provided. Further, before any request to the California PUC or the Oregon PUC to reduce or increase a surcharge in the event the amount needed for Customer Contribution is determined to be less or more than the level of Customer Contribution specified in Section 7.3.2.A, the States and PacifiCorp shall undertake to consult with all Parties.

4.10 United States Not Responsible for Costs of Facilities Removal

The United States shall not be liable or responsible for costs of Facilities Removal.

4.11 Parties' Costs Related to Facilities Removal

Subject to Section 4.4, the funds accumulated pursuant to Section 4 are solely for use in accomplishing Facilities Removal, including but not limited to development of the Definite Plan, all necessary permitting and environmental compliance actions, and construction/project management for Facilities Removal. Nothing in this section shall be interpreted as a limitation on the State of California's use of California Bond Funding, or funds collected pursuant to the California Klamath Surcharge and deposited into the California Copco 1 and 2 and Iron Gate Dams Trust Account, for environmental review; provided the use of any funds from California Copco 1 and 2 and Iron Gate Dams Trust Account may be offset by California Bond Funds to achieve the target dates set forth in Section 7.3.

4.12 Funding and Grant Agreements

4.12.1 On or around June 15, 2016, CNRA will enter into an agreement with the DRE pertaining to the use of funds from the Customer Contribution and California Bond Funding.

4.12.2 On or around June 15, 2016, and as is necessary at any time thereafter, the DRE will enter into an agreement with the Oregon PUC pertaining to the use of funds from the Customer Contribution in a manner not inconsistent with the Settlement and ORS 757.738(3).

4.12.3 On or around June 15, 2016, CNRA will enter into a funding agreement with the DRE and any other entity as appropriate. The funding agreement will include conditions not inconsistent with the Settlement pertaining to the use of the California Klamath Trust Accounts.

4.12.4 Following appropriation by the California legislature and consistent with the agreement in Section 4.12.1, CNRA will enter into a grant agreement(s) with the DRE. The grant agreement(s) shall include conditions not inconsistent with the Settlement pertaining to the use of the California Bond Funding.

5. Local Community Power

5.1 Power Development

5.1.1 PacifiCorp and the irrigation-related Parties will in good faith cooperate in the investigation or consideration of joint development and ownership of renewable generation resources and the purchase by PacifiCorp of power from renewable energy projects developed by KWAPA or other parties related to the Klamath Reclamation Project or off-project irrigators. PacifiCorp and interested Public Agency Parties will in good faith cooperate in the investigation or consideration of joint development and ownership of potential renewable generation resources and the purchase by PacifiCorp of power from renewable energy projects developed by interested Public Agency Parties. Nothing in this Settlement requires any Party to enter into a specific transaction related to such development, ownership or purchase, but PacifiCorp, interested Public Agency Parties and the irrigation-related Parties desire to take actions in their mutual beneficial interest where opportunities arise.

5.1.2 Pursuant to that certain Memorandum of Understanding dated October 15, 2001 among the Western Governors Association and various federal agencies, the Secretary and the State of California shall seek to designate Siskiyou County as a Western Renewable Energy Zone and the Secretary and the State of Oregon shall seek to designate Klamath County as a Western Renewable Energy Zone. The Federal Parties will work with the Counties and other Parties to explore and identify potential ways to expand transmission capacity for renewable resources within the Counties.

5.2 [Section deleted]

5.3 Transmission and Distribution of Energy

Interior, KWAPA, KWUA and UKWUA agree that federal power can contribute to meeting power cost targets for irrigation in the Upper Klamath Basin. To that end, and consistent with applicable standards of service and the Pacific Northwest Power Planning and Conservation Act, 16 U.S.C. § 839 *et seq*., Interior will acquire power from the Bonneville Power Administration ("Bonneville") to serve all "eligible loads" located within Bonneville's authorized geographic area. Interior and Bonneville will engage in an open and transparent process that will provide for public review and comment on any proposed agreement. For purposes of the acquisition of federal power, Interior defines Klamath eligible loads to include both on and off-project loads. Such acquisitions are subject to Bonneville's then effective marketing policies, contracts, and applicable priority firm power rate.

For an additional, standard transmission charge, Bonneville will deliver power to PacifiCorp at the Captain Jack or Malin substations or other points as may be mutually agreed to by Bonneville and PacifiCorp ("Points of Delivery") and PacifiCorp will deliver the energy to eligible loads under applicable tariffs.

Interior, KWAPA, KWUA, UKWUA and PacifiCorp agree to continue to work in good faith to identify and implement a mutually agreeable approach for delivering acquired federal power to eligible loads. PacifiCorp agrees to receive any federal power at the Points of Delivery and to deliver such power to the eligible loads pursuant and subject to the following terms and conditions:

5.3.1 The terms and conditions related to accessing PacifiCorp's transmission system, to the extent that it is necessary, will be consistent with PacifiCorp's Open Access Transmission Tariff ("OATT").

5.3.2 The terms and conditions related to accessing PacifiCorp's distribution system will remain subject to the jurisdiction of the California Public Utilities Commission for distribution facilities located in California and the Oregon Public Utility Commission for distribution facilities located in Oregon. In California and Oregon, the respective PUCs have approved unbundled delivery service tariffs for PacifiCorp to implement direct access legislation. The Parties agree that these unbundled delivery service tariffs can enable the delivery of federal power. For power acquired by Interior from Bonneville, PacifiCorp will charge an unbundled distribution rate that is based on the Oregon Commission-approved tariff applicable to the delivery of Bonneville power to eligible loads in Oregon.

To the extent that PacifiCorp's existing tariffs require revision in order to allow PacifiCorp to implement the mutually agreeable approach, PacifiCorp shall request such revision by the Commission having jurisdiction.

The Parties understand and agree that PacifiCorp shall recover its costs incurred in providing the delivery services required under the mutually agreeable approach and that such services will not be subsidized by PacifiCorp's other retail customers. PacifiCorp, Interior, KWUA, KWAPA, and UKWUA agree to work cooperatively to identify and analyze, as necessary, PacifiCorp's costs for delivery services as part of identification of any such mutually agreeable approach. The Parties further agree that the costs of providing delivery services will be recovered pursuant to a tariff or tariffs established by the respective PUC based on cost-of-service principles and a finding by the PUC that the rates charged under the tariff[s] are fair, just, reasonable and sufficient.

5.3.3 PacifiCorp agrees to work in good faith to develop mutually agreeable revisions to existing provisions of state or federal law, if necessary to implement the mutually agreeable approach.

5.3.4 PacifiCorp agrees to work in good faith with Bonneville, Interior, KWAPA, KWUA and UKWUA and other Parties as the case may be, to resolve, on a mutually agreeable basis, any technical and administrative issues (such as billing and metering) that may arise with respect to PacifiCorp's delivery of power to the eligible loads.

5.3.5 It is the Parties' intent that this Agreement will not require PacifiCorp to modify its existing transmission or distribution facilities. PacifiCorp may elect to do so at the sole cost and expense of the Party or entity requesting such modification.

5.3.6 At such time as the eligible loads are prepared to and technically able to receive federal power, PacifiCorp, Interior, KWAPA, KWUA and UKWUA agree to work cooperatively with each other to transition the eligible loads from full retail service on a mutually agreeable basis. The Parties acknowledge that for any eligible load that has received federal power pursuant to this section, PacifiCorp will no longer have the obligation to plan for or meet the generation requirements for these loads in the future, provided, however, that PacifiCorp agrees to work cooperatively to provide generation services to eligible loads in a manner that is cost-neutral to other PacifiCorp customers in the event that a contract for federal power is no longer available. Interior, KWAPA, KWUA and UKWUA agree to provide notice to PacifiCorp as soon as practicable after becoming aware that federal power will no longer be available to serve any eligible loads.

5.3.7 Interior, in consultation with KWAPA, KWUA and UKWUA, shall Timely develop a preliminary identification of the eligible loads for purposes of Section 5.3. Interior, in consultation with KWAPA, KWUA and UKWUA, shall provide notification to PacifiCorp identifying the final

eligible loads for purposes of Section 5.3, not later than 120 days before delivery of federal power to any such eligible loads is to begin. The mutually agreeable approach will address the manner by which Interior provides notification to PacifiCorp of any changes to eligible loads.

5.3.8 Interior agrees to work cooperatively to assign or delegate or transition functions of Interior to KWAPA or another appropriate entity subject to the terms of this Section.

5.3.9 If Interior or KWAPA or UKWUA are able to acquire power from any entity other than Bonneville for eligible loads in either Oregon or California, PacifiCorp, KWAPA, UKWUA, Interior, and KWUA, as applicable, will work cooperatively to agree on a method for transmission and delivery.

5.3.10 Upon termination of this Settlement, PacifiCorp agrees to provide service under the terms of its approved delivery tariff until or unless the respective PUC determines that the applicable tariff should no longer be in place. It is the intention of PacifiCorp, Interior, KWUA, KWAPA, and UKWUA that the general principles of cooperation expressed in Section 5 continue beyond the term of this Settlement.

5.4 Irrigator Rates

In consultation with Klamath Basin irrigators, PacifiCorp will continue to explore alternative rate structures and programs, such as time-of-use rates or demand control programs.

6. Interim Operations

6.1 General

Interim Measures under this Settlement consist of: (1) Interim Measures included as part of PacifiCorp's Interim Conservation Plan ("ICP Interim Measures") (Appendix C); and (2) Interim Measures not included in the Interim Conservation Plan ("Non-ICP Measures") (Appendix D). In addition, PacifiCorp's Interim Conservation Plan includes certain measures for protection of listed sucker species not included as part of this Settlement.

6.1.1 PacifiCorp Performance

PacifiCorp shall perform the Interim Measures in accordance with the terms and schedule set forth in Appendices C and D as long as this Settlement is in effect during the Interim Period. However, if this Settlement terminates, PacifiCorp shall continue performance of the Iron Gate Turbine Venting until the time FERC issues an order in the relicensing proceeding. PacifiCorp shall have no obligation

under this Settlement to perform any other of the Interim Measures if this Settlement terminates, but may implement certain ICP and Non-ICP Interim Measures for ESA or CWA purposes or for any other reason. PacifiCorp reserves its right to initiate termination pursuant to Section 8.11.1.C, if the Services fail to provide incidental take authorization in a Timely way.

6.1.2 Duty to Support

Subject to the reservations in Sections 1.6, 6.2, and 6.3.4, each Party shall support the Interim Measures set forth in Appendices C and D, and will not advocate additional or alternative measures for the protection of environmental resources affected by the Project during the Interim Period.

6.1.3 Permitting

A. PacifiCorp or the DRE (as applicable) shall comply with all federal, state, and local laws and obtain all federal, state, and local permits related to Interim Measures, to the extent such laws and permits are applicable.

B. FERC Enforcement and Jurisdiction

(1) The Parties agree that enforcement of the terms of the current license, as extended through annual licenses, shall be exclusively through FERC. If the annual license is amended to incorporate any of the Interim Measures, a Party may seek compliance pursuant to any remedies it may have under Applicable Law.

(2) Subject to the reservations in Section 6.3.4, PacifiCorp will implement Interim Measures and the Klamath River TMDLs, subject to any necessary FERC or other Regulatory Approvals.

6.1.4 Interim Power Operations

Consistent with the operation and maintenance agreement contemplated in Section 7.1.6, PacifiCorp shall continue to operate the Facilities for the benefit of customers and retain all rights to the power from the Facilities until each Facility is transferred and Decommissioned, including all rights to any power generated during the time between transfer of the Facility to the DRE and Decommissioning of the Facility by PacifiCorp.

6.1.5 Adjustment for Inflation

For any funding obligation under a Non-ICP Interim Measure in Appendix D expressly made subject to adjustment for inflation, the following formula shall be applied at the time of payment:

$$AD = D \times (CPI\text{-}U_t) / (CPI\text{-}U_o))$$

WHERE:

AD = Adjusted dollar amount payable.
D = Dollar amount prescribed in the Interim Measure.
$CPI\text{-}U_t$ = the value of the published version of the Consumer Price Index-Urban for the month of September in the year prior to the date a dollar amount is payable. (The CPI-U is published monthly by the Bureau of Labor Statistics of the federal Department of Labor. If that index ceases to be published, any reasonably equivalent index published by the Bureau of Economic Analysis may be substituted by written agreement of the Parties.)
$CPI\text{-}U_o$ = the value of the Consumer Price Index-Urban for the month and year corresponding to the Effective Date of this Settlement.

6.2 Interim Conservation Plan

6.2.1 Application by PacifiCorp

PacifiCorp shall apply to the Services pursuant to ESA Section 10 and applicable implementing regulations to incorporate the Interim Conservation Plan measures, including both Appendix C (ICP Interim Measures) and the Interim Conservation Plan measures for protection of listed sucker species not included in Appendix C, into an incidental take permit. PacifiCorp also may apply in the future to FERC to incorporate some or all of the Interim Conservation Plan measures as an amendment to the current annual license for the Project.

6.2.2 Applicable Actions by the Services under the ESA

The Services shall review PacifiCorp's application to incorporate the Interim Conservation Plan measures into an incidental take permit pursuant to ESA Section 10 and applicable implementing regulations. Subject to Section 2.1.2, each Party shall support PacifiCorp's request for a license amendment or incidental take permit to incorporate the Interim Conservation Plan measures. Provided, however, the Services reserve their right to reassess these interim measures, as applicable, in: (1) developing a biological opinion pursuant to ESA Section 7 or reviewing an application for an incidental take permit pursuant to ESA Section 10 and applicable implementing regulations; (2) reinitiating consultation on any final biological opinion pursuant to applicable implementing regulations; or (3) revoking any final incidental take permit pursuant to the ESA, applicable implementing regulations, or the terms of the permit. Provided further, other Parties reserve any applicable right to oppose any such actions by the Services.

6.2.3 Potential Modifications of Measures

The Services shall provide the Parties Notice upon issuance of any final biological opinion or incidental take permit issued by the Services pursuant to the ESA regarding the ICP Interim Measures (Appendix C). If the terms of any such final biological opinion or incidental take permit include revisions to the ICP Interim Measures, those measures in the Settlement shall be deemed modified to conform to the provisions of the biological opinion or incidental take permit if PacifiCorp agrees to such modifications. If PacifiCorp does not agree to such modifications, PacifiCorp reserves the right to withdraw its application for license amendment or refuse to accept an incidental take permit regarding the ICP Interim Measures.

6.3 TMDLs

6.3.1 PacifiCorp Implementation

Subject to the provisions of this Section 6.3.1, PacifiCorp agrees to implement load allocations and targets assigned the Project under the States' respective Klamath River TMDLs, in accordance with OAR chapter 340, Division 42, and California Water Code Division 7, Chapter 4, Article 3. It is the expectation of the Parties that the implementation of the commitments in this Settlement, coupled with Facilities Removal by the DRE, will meet each State's applicable TMDL requirements. PacifiCorp's commitment to develop and carry out TMDL implementation plans in accordance with this Settlement is not an endorsement by any Party of the TMDLs or load allocations therein.

6.3.2 TMDL Implementation Plans

A. No later than 60 days after ODEQ's and the North Coast Regional Water Quality Control Board's (NCRWQCB's) approval, respectively, of a TMDL for the Klamath River, PacifiCorp shall submit to ODEQ and NCRWQCB, as applicable, proposed TMDL implementation plans for agency approval. The TMDL implementation plans shall be developed in consultation with ODEQ and NCRWQCB.

B. To the extent consistent with this Settlement, PacifiCorp shall prepare the TMDL implementation plans in accordance with OAR 340-042-0080(3) and California Water Code section 13242, respectively. The plans shall include a timeline for implementing management strategies and shall incorporate water quality-related measures in the Non-ICP Interim Measures set forth in Appendix D. Facilities Removal by the DRE shall be the final measure in the timeline. At PacifiCorp's discretion, the proposed plans may further include other planned activities and management strategies developed individually or cooperatively with other sources or designated management agencies. ODEQ and NCRWQCB may authorize PacifiCorp's use of offsite

pollutant reduction measures, subject to an iterative evaluation and approval process; provided, any ODEQ authorization of such offsite measures conducted in Oregon solely to facilitate attainment of load allocations in California waters shall not create an ODEQ obligation to administer or enforce the measures.

6.3.3 Keno Load Allocation

Subject to Section 6.3.4, in addition to other Project facilities and affected waters, PacifiCorp's TMDL implementation plan under Section 6.3.2 shall include water quality-related measures in the Non-ICP Interim Measures set forth in Appendix D that are relevant to the Keno facility and affected waters for which the Project is assigned a load allocation. PacifiCorp shall implement Keno load allocations in accordance with the approved TMDL implementation plan under Section 6.3 up until the time of transfer of title to the Keno facility to Interior. Upon transfer of title to the Keno facility as set forth in Section 7.5 of this Settlement, the load allocations shall no longer be PacifiCorp's responsibility. Funding, if necessary, for post-transfer Keno load allocation implementation requirements will be provided by other non-PacifiCorp sources.

6.3.4 TMDL Reservations

A. PacifiCorp's TMDL implementation obligations under this Settlement are limited to the water quality-related measures in the Interim Measures set forth in Appendices C and D and any additional or different measures agreed to by PacifiCorp and incorporated into an approved TMDL implementation plan. If a TMDL implementation plan for PacifiCorp as finally approved, or a final discharge permit or other regulatory decision intended to implement a TMDL or water quality standard or regulation, requires measures that have not been agreed to by PacifiCorp and that are materially inconsistent with the Interim Measures, PacifiCorp may initiate termination under Section 8.11.1.C.

B. PacifiCorp reserves the right to seek modification of a TMDL implementation plan in the event this Settlement terminates. The States reserve their authorities under the CWA and state law to revise or require submission of new TMDL implementation plans in the event this Settlement terminates or an implementation plan measure or Facilities Removal does not occur in accordance with the timeline in the approved implementation plans. Other Parties reserve whatever rights they may have under existing law to challenge the TMDLs or TMDL implementation plans in the event this Settlement terminates.

C. To the extent it possesses rights outside of this Settlement, no Party waives any right to contest: a Klamath River TMDL; specific TMDL

load allocation; decision on a PacifiCorp TMDL implementation plan; or final discharge permit or other regulatory decision intended to implement a TMDL or water quality standard or regulation, if materially inconsistent with this Settlement.

6.4 Other Project Works

6.4.1 East Side/West Side Facilities

A. PacifiCorp will apply to FERC for an order approving partial surrender of the Project license for the purpose of decommissioning the East Side/West Side generating facilities unless PacifiCorp, in consultation with the state of Oregon, the Federal Parties, and the Tribes, agrees to an alternative disposition of these facilities. PacifiCorp will file the application consistent with applicable FERC regulations, and after consultation with the Parties. Notwithstanding Section 2.1.2, the Parties reserve their rights to submit comments and otherwise participate in the FERC proceeding regarding the conditions under which decommissioning should occur. PacifiCorp reserves the right to withdraw its surrender application for these facilities if any FERC order or other Regulatory Approval in connection with the surrender application would impose unreasonable conditions on that surrender.

B. Upon FERC approval, and in coordination with Reclamation and pursuant to Section 7.5.2, PacifiCorp shall decommission the East Side/West Side facilities in accordance with the FERC order approving the decommissioning, with the costs of such decommissioning to be recovered by PacifiCorp through standard ratemaking proceedings.

C. Upon completion of decommissioning and subject to FERC's and state requirements, PacifiCorp and Interior shall discuss possible transfer of the following lands to Interior: Klamath County Map Tax Lots R-3809-00000-05800-000, R-3809-00000-05900-000, and R-3809-00000-05700-000, or any other mutually-agreeable lands associated with the East Side and West Side Facilities on terms and conditions acceptable to PacifiCorp and Interior.

6.4.2 Fall Creek Hydroelectric Facility

PacifiCorp will continue to operate the Fall Creek hydroelectric facility under FERC's jurisdiction unless and until such time as it transfers the facility to another entity or the facility is otherwise disposed of in compliance with Applicable Law.

6.5 Abeyance of Relicensing Proceeding

6.5.1 Within 30 days of the Amendment Effective Date, PacifiCorp will file the Settlement with FERC and an expedited motion asking FERC to hold PacifiCorp's Project relicensing proceeding in abeyance. Each Party agrees to refrain from any action that does not support PacifiCorp's request to abate the FERC relicensing docket for the Project. The motion will specify that the abeyance should remain in effect while the DRE's surrender application is pending and until after FERC takes action on the DRE's surrender application as provided in Section 7.1.7.A.

6.5.2 Within 15 days after FERC issues an abeyance order for the Project relicensing proceeding, PacifiCorp will withdraw its CWA Section 401 certification applications currently pending before the California State Water Resources Control Board and ODEQ.

6.5.3 If FERC denies PacifiCorp's motion to abate or fails to rule on the motion before July 1, 2016, PacifiCorp will ask the California State Water Resources Control Board and the ODEQ to abate permitting and environmental review for PacifiCorp's FERC Project No. 2082 licensing activities, including but not limited to water quality certifications under Section 401 of the CWA and review under CEQA, during the Interim Period. If FERC does not hold the Project relicensing proceeding in abeyance, PacifiCorp will withdraw and re-file its relicensing applications for Section 401 certifications as necessary to avoid the certifications being deemed waived under the CWA during the Interim Period.

6.5.4 If no abeyance of relicensing proceedings is approved by FERC or, as applicable, the California State Water Resources Control Board or the ODEQ, or an abeyance is ordered then later lifted, then the Parties are excused from their duty to support this Settlement to the extent necessary to maintain their rights and arguments in the Project relicensing proceedings, and any Party may initiate the Meet and Confer procedures described in Section 8.7.

7. DRE, Transfer, Surrender, and Facilities Removal

This section describes the measures, schedule, and regulatory compliance during transfer, surrender, and removal of Facilities under this Settlement.

7.1 DRE

7.1.1 Execution of Settlement

The Parties expect that the DRE will become a Party by executing the Settlement on or around July 1, 2016, as provided in Section 9.4.

7.1.2 Capabilities

A. The Parties agree that the DRE must possess the legal, technical, and financial capacity to:

(1) Accept and expend non-federal funds consistent with Section 4.2.4;

(2) Accept transfer of the FERC license and title for the Facilities from PacifiCorp;

(3) Seek and obtain necessary permits and other authorizations to implement Facilities Removal;

(4) Enter into appropriate contracts and grant agreements for effectuating Facilities Removal;

(5) Perform, directly or by oversight, Facilities Removal;

(6) Prevent, mitigate, and respond to damages the DRE or any of its contractors, subcontractors, or assigns cause during the course of Facilities Removal, and, consistent with Applicable Law, respond to and defend associated liability claims against the DRE or any of its contractors, subcontractors, or assigns, including costs thereof and any judgments or awards resulting therefrom;

(7) Carry the required insurance and bonding set forth in Appendix L to respond to liability and damages claims associated with Facilities Removal against the DRE or any of its contractors, subcontractors, or assigns;

(8) Meet the deadlines set forth in Exhibit 4; and

(9) Perform such other tasks as are reasonable and necessary for Facilities Removal.

B. Before the DRE and PacifiCorp file the joint application to transfer the license for the Facilities, the DRE will Timely demonstrate to the reasonable satisfaction of the States and PacifiCorp that it possesses the legal, technical, and financial capacity to accomplish the tasks in Sections 7.1.2.A(1) through (5), (8), and (9). PacifiCorp and the States will consult if the DRE fails to make the demonstration required in this subsection.

C. Within six months of the DRE's execution of the Settlement, the DRE will include in an informational filing in the FERC license transfer

proceeding proof that it possesses the legal, technical, and financial capacity to accomplish the tasks in Sections 7.1.2.A(6) and (7). This filing will include documentation that the DRE meets the requirements of Parts II, III, and IV of Appendix L and is capable of fulfilling its obligations under Section 7.1.3. The DRE will not provide the filing if either of the States or PacifiCorp objects to the filing after a reasonable opportunity to review before submission to FERC. The six-month deadline may be changed by agreement of the DRE, the States, and PacifiCorp. The Parties will Meet and Confer if the DRE fails to provide the informational filing to FERC.

7.1.3 Liability Protection

A. By executing this Settlement, the DRE agrees, on its behalf and on behalf of the DRE's employees, contractors, subcontractors, and authorized agents or assigns to indemnify, hold harmless, and defend PacifiCorp, the state of California, and the state of Oregon for, from, and against any and all claims, actions, proceedings, damages, liabilities, monetary or non-monetary harms or expense arising from, relating to, or triggered by Facilities Removal, including but not limited to:

(1) Harm, injury, or damage to persons, real property, tangible property, natural resources, biota, or the environment;

(2) Harm, injury, or damage caused by the release, migration, movement, or exacerbation of any material, object, or substance, including without limitation hazardous substances; and

(3) Breaches or violations of any Applicable Law, Regulatory Approval, authorization, agreement, license, permit, or other legal requirement of any kind.

B. If the DRE partially assigns its responsibilities under this Settlement, the DRE and its assign will be jointly and severally obligated under this section.

7.1.4 License Transfer Conditions and Timing

Before the FERC license transfer to the DRE will become effective, the DRE must demonstrate to PacifiCorp's and the States' reasonable satisfaction that the DRE has met the obligations in Appendix L and the following conditions:

A. The DRE has provided Notices required under Section 7.2.1.B;

B. The DRE has met the requirements of Section 7.1.3 and Appendix L;

C. PacifiCorp and the States agree that the DRE has made sufficient and Timely progress in obtaining necessary permits and approvals to effectuate Facilities Removal;

D. The DRE, the States, and PacifiCorp are assured that sufficient funding is available to carry out Facilities Removal;

E. The DRE, the States, and PacifiCorp are each assured that their respective risks associated with Facilities Removal have been sufficiently mitigated consistent with Appendix L;

F. The DRE, the States, and PacifiCorp agree that no order of a court or FERC is in effect that would prevent Facilities Removal;

G. The DRE and PacifiCorp have executed documents conveying the property and rights necessary to carry out Facilities Removal; and

H. The DRE accepts license transfer under the conditions specified by FERC in its order approving transfer.

7.1.5 FERC Application for Transfer

A. On or around July 1, 2016, PacifiCorp and the DRE will jointly file an application to remove the Facilities from the Project license, redesignate the Facilities with a new project number, and transfer the redesignated FERC license for the Facilities to the DRE.

B. The application for transfer may include proposals to decommission the East Side and West Side facilities, subject to Section 6.4.1 of this Settlement; remove the Keno facilities from the Project license under Section 7.5 of this Settlement; and transfer the Fall Creek development to a third party for purposes of relicensing.

C. PacifiCorp and the DRE will file the joint application for transfer at FERC concurrent with the DRE's application for surrender and removal of the Facilities, retaining the 2020 target date for Facilities Removal.

D. The joint application for transfer will request that FERC incorporate the conditions in Section 7.1.4 into the transfer order and require that transfer will not become effective until the DRE, or PacifiCorp and the DRE jointly (as appropriate), file notice with FERC when those conditions have been satisfied.

7.1.6 Operation and Maintenance Agreement

On or around July 1, 2016, the DRE and PacifiCorp will enter into an operation and maintenance agreement allowing PacifiCorp to continue operating the Facilities for the benefit of its customers following transfer of the FERC Facilities license to the DRE. The conditions of operation under this agreement will be consistent with interim operations described in Section 6 and Appendices B, C, and D, and will include requirements that PacifiCorp pay all costs associated with operating the Facilities and indemnify, defend, and hold harmless the DRE with respect to those operations. The DRE and PacifiCorp will obtain the concurrence of the States for any such agreement.

7.1.7 FERC Application for Surrender

A. Concurrently with the joint application for license transfer, the DRE will file an application with FERC to surrender the FERC license for the Facilities for the purpose of Facilities Removal, which will include a copy of this Settlement and the Detailed Plan. The DRE will request that FERC defer acting on the application until the conditions in Section 7.1.4 are satisfied. The DRE will take any action necessary to obtain necessary FERC authorization to carry out Facilities Removal in accordance with this Settlement. PacifiCorp will provide technical support to the DRE and to FERC in processing the surrender application, but will not be a co-applicant or co-licensee on the surrender application unless otherwise mutually agreed upon with the DRE.

B. Concurrently with the joint application for license transfer and the DRE's application to FERC for surrender, the DRE will file applications seeking state water quality 401 certifications for Facilities Removal with the California State Water Resources Control Board and the ODEQ.

7.1.8 Performance of Facilities Removal

The DRE will perform Facilities Removal in accordance with the Definite Plan, as approved and as may be modified by the FERC surrender order and other applicable Regulatory Approvals. The DRE will complete final design and cost estimates before initiating Facilities Removal.

7.1.9 Other Regulatory Approvals for Facilities Removal

The DRE will take any action necessary to obtain other Regulatory Approvals necessary to effectuate Facilities Removal in accordance with this Settlement, except that PacifiCorp will file and support applications to obtain the necessary

state commission approvals for the transfer of assets to the DRE in accordance with this Settlement.

7.1.10 Assignment

The DRE may assign to another entity any of its responsibilities under this Settlement, including the DRE responsibilities described in this section. This assignment is subject to any necessary Regulatory Approvals. The DRE may not assign its responsibilities under this Settlement without the prior written consent of the States and PacifiCorp.

7.2 Definite Plan and Detailed Plan

7.2.1 Development and Use of Definite Plan

The DRE will develop a Definite Plan for Facilities Removal that, once completed, may be included as a part of any applications for permits or other authorizations. The Definite Plan must be consistent with this Settlement.

A. Elements of Definite Plan

The Definite Plan may be based on all elements of the Detailed Plan described in Section 7.2.2 and will be consistent with FERC requirements for surrender. Such elements shall be in the form required for physical performance, such as engineering specifications for a construction activity, and shall also include consideration of prudent cost overrun management tools such as performance bonds. The Definite Plan shall also include:

(1) A detailed estimate of the actual or foreseeable costs associated with: the physical performance of Facilities Removal consistent with the Detailed Plan; each of the tasks associated with the performance of the DRE's obligations as stated in Section 7.1; seeking and securing permits and other authorizations; and insurance, performance bond, or similar measures, as set forth in Appendix L to this Settlement;

(2) The DRE's analysis demonstrating that the total cost of Facilities Removal is likely to be less than the State Cost Cap, which is the total of Customer Contribution and California Bond Funding as specified in Section 4;

(3) Appropriate procedures consistent with state law to provide for cost-effective expenditures within the cost estimates stated in (1);

(4) Accounting procedures that will result in the earliest practicable disclosure of any actual or foreseeable overrun of cost of any task relative to the detailed estimate stated in (1); and

(5) Appropriate mechanisms to modify or suspend performance of any task subject to such overrun. Upon receipt of Notice from the DRE of any actual or foreseeable cost overrun pursuant to (2), the Parties shall use the Meet and Confer procedures to modify the task (to the extent permitted by the FERC surrender order, an applicable permit, or other authorization) or to modify this Settlement as appropriate to permit Facilities Removal to proceed.

B. Notice of Completion

The DRE shall provide Notice to the Parties upon completion of the Definite Plan.

C. Use of Definite Plan

The DRE must incorporate the Definite Plan, once completed, into any FERC application to surrender the Facilities license. After FERC issues an order on the FERC Facilities license surrender application, the Parties will review the consistency of the Definite Plan, FERC's surrender order, and this Settlement. If either of the States or the DRE finds that the FERC surrender order is materially inconsistent (as defined in Section 8.11.2) with the Definite Plan or this Settlement, either the DRE or the States may initiate Meet and Confer proceedings.

7.2.2 Detailed Plan for Facilities Removal

The Secretary developed the Detailed Plan, which may serve as a basis for the Definite Plan described in Section 7.2.1.A. The Detailed Plan includes A through F below; G is addressed in Appendix L and will be fully developed in the Definite Plan; H will be addressed during solicitation and selection of engineering and construction contract(s) for development of a Definite Plan and for Facilities Removal.

A. The physical methods to be undertaken to effect Facilities Removal, including but not limited to a timetable for Facilities Removal, which is removal of all or part of each Facility as necessary to effect a free-flowing condition and volitional fish passage as defined in Section 1.4;

B. As necessary and appropriate, plans for management, removal, and/or disposal of sediment, debris, and other materials;

C. A plan for site remediation and restoration;

D. A plan for measures to avoid or minimize adverse downstream impacts;

E. A plan for compliance with all Applicable Laws, including anticipated permits and permit conditions;

F. A detailed statement of the estimated costs of Facilities Removal;

G. A statement of measures to reduce risks of cost overruns, delays, or other impediments to Facilities Removal; and

H. The qualifications, management, and oversight of a non-federal DRE.

7.2.3 Assessment and Mitigation of Potential Impacts to the City of Yreka

The Parties understand that actions related to this Settlement may affect the City of Yreka. In recognition of this potential, the Parties agree to the following provisions, which shall remain in effect so long as this Settlement remains in effect.

A. The Parties collectively and each Party individually shall agree not to oppose the City of Yreka's continued use of California State Water Right Permit 15379, which provides for the diversion of up to 15 cfs for municipal uses by the City of Yreka.

B. As part of implementation of this Settlement, an engineering assessment to study the potential risks to the City of Yreka's water supply facilities as a result of implementation of Facilities Removal shall be funded and conducted by the Secretary. Actions identified in the engineering assessment necessary to assure continued use of the existing, or equivalent replacement, water supply facilities by the City of Yreka shall be funded from the California Bond Measure and implemented. Actions that may be required as a result of the engineering assessment and in consultation with the City of Yreka include, but are not limited to:

(1) Relocation, replacement, and/or burial of the existing 24-inch diameter water line and transmission facilities from the City of Yreka's Fall Creek diversion;

(2) Assessment, mitigation, and/or funding to address potential damage to the City of Yreka's facilities located along the Klamath River, including mitigation of potential impacts that may occur as a result of a dam breach. Such assessment, mitigation, and/or funding shall include consideration of the cathodic protection field located near the north bank of the Iron Gate crossing and the facilities that house the City's diversion and pump station; and

(3) Assessment, mitigation, and/or funding to address any impacts resulting from implementation of the Settlement, on the ability of the City to divert water consistent with its Water Right Permit 15379.

C. As part of implementation of this Settlement, an assessment of the potential need for fish screens on the City of Yreka's Fall Creek diversion facilities was completed in the Detailed Plan and it identified the need for fish screens on Dam A and Dam B. As a result of implementation of this Settlement, in order to meet regulatory requirements and screening criteria, construction of the required fish screens, including, but not limited to, necessary costs to preserve City facilities with additional species protection, shall be funded through the California Bond Measure pursuant to Section 4.2.3, or through other appropriate sources.

7.3 Schedule for Facilities Removal

7.3.1 The Parties agree that the target date to begin Facilities Removal is January 1, 2020. The Parties agree that preparatory work for Facilities Removal may be undertaken by the DRE before January 1, 2020, consistent with the Definite Plan, applicable permits, and Section 6 of this Settlement; provided such preparatory work shall not have any negative impact on PacifiCorp's generation operations at the Facilities. The Parties further agree to a target date of December 31, 2020 for completion of Facilities Removal at least to a degree sufficient to enable a free-flowing Klamath River allowing volitional fish passage.

7.3.2 The Parties acknowledge and agree that the schedule to accomplish Facilities Removal will be determined by the DRE in accordance with Section 7.3.4. The Parties intend to implement this Settlement based on the following approach to achieve the target dates for Decommissioning and Facilities Removal set forth in Section 7.3.1:

A. Collect $172 million of the total Customer Contribution by December 31, 2019, consistent with Section 4;

B. Earn approximately $28 million in interest on the Klamath Trust Accounts to provide Value to Customers, which results in a total of $200 million in the accounts available for Facilities Removal costs as illustrated in Appendix H to this Settlement;

C. Implement Decommissioning and Facilities Removal in a manner that permits PacifiCorp to generate sufficient electricity at the Facilities to achieve the economic results included in PacifiCorp's Economic Analysis; and

D. Implement the ICP and Non-ICP Interim Measures set forth in Appendices C and D to this Settlement.

7.3.3 The Parties agree that PacifiCorp may continuously operate the Facilities subject to the ICP and Non-ICP Interim Measures identified in Appendices C and D to this Settlement and generate electricity at the Facilities through December 31, 2019. Based upon PacifiCorp's representation of its Economic Analysis, the Parties agree that the following additional Value to Customers, in addition to the $28 million in interest described in Section 7.3.2.B, is necessary to achieve the corresponding date for commencement of Facility Decommissioning:

Date of Facilities Decommissioning	Required Additional Value to Customers
January 1, 2020	$27 million
July 1, 2020	$13 million
December 31, 2020	$0

If Decommissioning begins on December 31, 2020, no additional funding is required. The Parties acknowledge that, in order to complete Facilities Removal to the degree described in the last sentence of Section 7.3.1 by December 31, 2020, Decommissioning will need to begin prior to that date. As described in the table above, Decommissioning may begin on July 1, 2020 if $13 million in additional Value to Customers is identified, or on January 1, 2020, if $27 million in additional Value to Customers is identified.

7.3.4 Within 90 days of the DRE's execution of the Settlement, or at such additional time as may be necessary, the Parties shall Meet and Confer to: (1) review progress in implementing the Settlement based upon the approach described in Section 7.3.2; (2) review the DRE's schedule to procure contractor(s) to prepare a Definite Plan based on the Detailed Plan and to provide required liability protection and risk mitigation in accordance with Appendix L; and (3) identify the Value to Customers necessary to implement the schedule, the mechanisms as described in Section 7.3.8 that will be used, and the estimated cost reduction from each mechanism through December 2019. The Parties will subsequently Meet and Confer if the estimated additional Value to Customers has not been timely secured, a Regulatory Approval is inconsistent with that schedule, or the Definite Plan or final designs are inconsistent with the schedule.

If the Parties determine that the identified Value to Customers is less than the amount required to achieve the schedule, then the Parties at that time will consider additional actions to address the funding deficiency, including but not limited to extending the schedule and securing additional funding to protect PacifiCorp customers. The Parties may thereafter Meet

and Confer if additional Value to Customers is secured in excess of what was previously estimated.

7.3.5 PacifiCorp, in its sole and absolute discretion, may determine that Facilities Removal may begin earlier than January 1, 2020.

7.3.6 If the Parties determine that the schedule for Facilities Removal must extend beyond December 31, 2020, then the Parties shall also consider whether (1) modification of Interim Measures is necessary to appropriately balance costs to customers and protection of natural resources, and (2) continuation of the collection of the customer surcharges up to the maximum Customer Contribution is warranted.

7.3.7 The Parties agree that if Decommissioning and Facilities Removal occurs in a staged manner, J.C. Boyle is intended to be the last Facility decommissioned. If, however, the Definite Plan or FERC's surrender order directs a different sequence for Decommissioning and Facilities Removal, then the Parties shall Meet and Confer to identify adjustments necessary to implement Facilities Removal in a manner that is consistent with PacifiCorp's Economic Analysis.

7.3.8 The Parties have identified the following potential mechanisms for creating Value to Customers:

A. Interest on the Klamath Trust Accounts

The Parties acknowledge above that the surcharges from the Customer Contributions will be placed in interest-bearing accounts and that the interest that accrues in the accounts may be used to reduce the amount collected through the surcharges so that the total Customer Contribution, including accrued interest through December 31, 2019, totals $200,000,000. The Parties further acknowledge that it is not possible to precisely estimate the amount of interest that will accrue in the Klamath Trust Accounts. To the extent the interest in the accounts exceeds $28,000,000, the additional earnings may be used as a Value to Customers unless the funds are required for Facilities Removal. Nothing in this paragraph will limit the Customer Contribution to less than $200,000,000.

B. Third-Party Funding

The Parties agree to work jointly to identify potential partnerships to supplement funds generated pursuant to this Settlement. Such third-party funds may be employed to acquire generation facilities that can be used to replace the output of the Facilities, to fund aspects of Facilities Removal, or for other purposes to achieve the benefits of this Settlement.

C. Other

The Parties acknowledge that other mechanisms for Value to Customers may be identified, provided that they create sufficiently quantifiable benefits for customers.

7.3.9 PacifiCorp's Economic Analysis that will be used to implement this section was filed by PacifiCorp with the Oregon PUC pursuant to Section 4(1) of the Oregon Surcharge Act and with the California PUC in accordance with Section 4 of this Settlement. The Parties may seek to intervene in these state proceedings before the Commissions, and may request to view PacifiCorp's Economic Analysis consistent with the limitations imposed by Section 4(6) of the Oregon Surcharge Act, applicable PUC protective orders, and general PUC discovery practices and legal requirements. PacifiCorp shall not oppose either request. PacifiCorp reserves the right to request that the PUCs restrict Parties' access to commercially sensitive material, other than PacifiCorp's Economic Analysis, consistent with Section 4(6) of the Oregon Surcharge Act, applicable PUC protective orders, and general PUC discovery practices and legal requirements.

7.4 Transfer, Decommissioning, and Facilities Removal

7.4.1 DRE Notice

The DRE will notify the Parties and FERC when the necessary permits and approvals have been obtained for removal of a Facility or Facilities, all contracts necessary for removal have been finalized, and Facility Removal is ready to commence.

7.4.2 Decommissioning and Transfer

PacifiCorp will transfer ownership of each Facility, including the underlying land for each Facility in accordance with Section 7.6.4 (except for the Keno Development, which shall be disposed in accordance with Section 7.5). Once the DRE fulfills all of the conditions and obligations in Section 7.1.4, Appendix L, and the FERC license transfer order, and PacifiCorp concurs, PacifiCorp will transfer ownership of the Facilities to the DRE. PacifiCorp will continue to operate and maintain the Facilities in accordance with Section 7.1.6 until the DRE is ready to begin removal of a Facility and requests that PacifiCorp discontinue operation of that Facility.

7.5 Keno Facility

7.5.1 Study

Resolution of issues surrounding Keno facility are an important part of achieving the overall goals of this Settlement. Accordingly, the Secretary, in consultation with affected Parties, shall study issues specific to the Keno facility, with specific focus on addressing water quality, fish passage, transfer of title to the Keno facility from PacifiCorp to Interior, future operations and maintenance, and landowner agreements. The study of the Keno facility will be designed with the goals of addressing these issues and maintaining the benefits the dam currently provides.

7.5.2 Keno Facility Determination

In 2012, the Bureau of Reclamation and PacifiCorp entered into an agreement in principle for transfer of title to the Keno facility from PacifiCorp to Interior. Within 60 days of the Amendment Effective Date, Interior and PacifiCorp shall commence negotiations on Keno transfer informed by the analyses described in Section 7.5.1. Every six months or as necessary after the Amendment Effective Date, and subject to Section 8.17, Interior and PacifiCorp shall report to the Parties on the status of Keno negotiations, including as appropriate, drafts of a proposed Keno transfer agreement, a summary of negotiations and issues in dispute, and supporting documents. Interior and PacifiCorp shall use their best efforts to complete a final Keno transfer agreement within 180 days of the Amendment Effective Date. The Secretary will accept transfer of title to the Keno facility when the DRE notifies the Parties and FERC pursuant to Section 7.4.1 that J.C. Boyle Facility Removal is ready to commence.

The transfer of title to the Keno facility shall be subject to completion of any necessary improvements to the Keno facility to meet Department of the Interior Directives and Standards criteria for dam safety identified by Interior through its Safety of Dams inspection of the Keno facility. To facilitate this inspection, PacifiCorp agrees to grant access to the federal government and its contractors for study and assessment of the Keno facility. The terms and conditions of the transfer of title to the Keno facility, including coordination of operations between Link River dam, Keno dam, and any remaining facilities operated by PacifiCorp, ingress and egress agreements and easements required for operation and maintenance of the Klamath Reclamation Project, including but not necessarily limited to Lake Ewauna, Link River Dam, and Keno Dam will be negotiated between Interior and PacifiCorp prior to transfer. Costs associated with any improvements necessary to meet Department of Interior's Directives and Standards criteria for dam safety shall be funded by other non-PacifiCorp sources.

7.5.3 PacifiCorp Operations Prior to Transfer

Prior to and until transfer of title to the Keno Facility, PacifiCorp shall operate Keno in compliance with Contract #14-06-200-3579A, subject to any Applicable Law including the CWA and the provisions of Section 6.3 of this Settlement.

7.5.4 Operations After Transfer

Following transfer of title to the Keno facility from PacifiCorp to Interior, Interior shall operate Keno in compliance with Applicable Law and to provide water levels upstream of Keno Dam for diversion and canal maintenance consistent with Contract #14-06-200-3579A executed on January 4, 1968, between Reclamation and PacifiCorp (then COPCO) and historic practice.

7.5.5 Landowner Agreements

Based on the analysis under Section 7.5.1, the Secretary, upon acquisition of the Keno facility, will execute new agreements with landowners who currently have agreements in the Lake Ewauna to Keno reach, as the Secretary determines are necessary to avoid adverse impacts to the landowners resulting from the transfer, consistent with Applicable Law, operational requirements, and hydrologic conditions.

7.6 Dispositions of PacifiCorp Interests in Lands and other Rights

7.6.1 Lands Owned by PacifiCorp

PacifiCorp is the fee owner of approximately 11,000 acres of real property located in Klamath County, Oregon and Siskiyou County, California that are not directly associated with the Klamath Hydroelectric Project, and generally not included within the existing FERC project boundary. This property is more particularly described on Page 3 of the PacifiCorp Land Maps, attached as Exhibit 3, and referenced as Parcel A. This Settlement shall have no effect as to disposition of Parcel A lands, which shall continue to be subject to applicable taxes unless and until disposed of by PacifiCorp subject to applicable PUC approval requirements.

PacifiCorp is the fee owner of approximately 8,000 acres of real property located in Klamath County, Oregon and Siskiyou County, California that is associated with the Klamath Hydroelectric Project and/or included within the FERC project boundary. This property is more particularly described on Page 3 of the PacifiCorp Land Maps, Exhibit 3, and referenced as Parcel B. It is the intent of the Parties that Parcel B property be disposed in accordance with Section 7.6.4, except for the Keno Development which shall be disposed in accordance with Section 7.5. In addition to Exhibit 3, PacifiCorp owns significant electric transmission and distribution facilities which will remain under its ownership and subject to applicable taxes.

7.6.2 Potential Non-Project Land Exchanges

Interior and PacifiCorp have identified in Parcel A the potential for the exchange of certain non-Project PacifiCorp-owned lands in the Klamath Basin. Should an exchange of these lands to a state or Federal entity take place, the terms of the exchange agreement shall be revenue-neutral to County governments.

7.6.3 BLM Easements and Rights of Way

The Parties agree that before Facilities Removal, the FERC license for the Facilities shall control the ingress and egress to the Facilities within the FERC project boundary. Access by PacifiCorp outside of the project boundary to BLM-administered lands may require a separate Right Of Way agreement.

The Parties agree that the DRE's obligations for operation, maintenance, remediation and restoration costs of BLM-administered, transportation-related structures affected by Facilities Removal will be addressed as part of the Definite Plan.

A proposed disposition of PacifiCorp's easements and right-of-ways across BLM-administered lands within the FERC Project boundary will be included as a part of the DRE's Definite Plan for Facility Removal. To the extent necessary, reciprocal Right Of Way agreements may be executed across PacifiCorp-owned lands and BLM-administered lands to provide continued access for public and BLM administration needs. During the implementation of the Definite Plan, the DRE will be required to obtain authorization for any access across PacifiCorp and BLM-administered lands necessary for every phase of action.

7.6.4 PacifiCorp Klamath Hydroelectric Project Lands

A. It is the intent of the Parties that ownership of PacifiCorp lands associated with the Klamath Hydroelectric Project and/or included within the FERC Project boundary, identified as Parcel B in Exhibit 3, shall be transferred to the DRE before Facilities Removal begins. It is the intent of the Parties that, once the DRE has completed Facilities Removal and all surrender conditions have been satisfied, ownership of these lands will be transferred to the respective States, as applicable, or to a designated third-party transferee, upon Notice by the relevant State that it has completed to its satisfaction a final property (land and facilities) inspection in accordance with Applicable Law and in accordance with the indemnification(s) provided in Section 7.1.3 and Appendix L. It is also the intent of the Parties that transferred lands shall thereafter be managed for public interest purposes such as fish and wildlife habitat restoration and enhancement, public education, and public recreational access.

B. Each State shall undertake inspection and preliminary due diligence regarding the nature and condition of Parcel B lands located within its state boundaries, in anticipation of transfer of those lands from the DRE to the relevant State. PacifiCorp and the DRE shall provide each State all cooperation and access to the lands and pertinent records necessary to the inspection and due diligence. The DRE, each State, and PacifiCorp shall identify and provide to the Parties, for each specific property in Parcel B: (1) the proposed transferee for the property; and (2) the proposed terms of transfer for the property. The States, the DRE, and PacifiCorp shall consult with the Parties and other stakeholders before identifying the proposed transfer of a specific Parcel B property. Following such evaluation, the State of Oregon and the State of California may, each in its sole and absolute discretion, elect not to accept the transfer of all or any portion of Parcel B lands; provided, if a State, the DRE, or PacifiCorp believes that the proposed transfer for a property (or lack thereof) will not achieve the intent set forth in Section 7.6.4.A, those Parties shall Meet and Confer in accordance with Section 8.7.

C. Without predetermining the final terms of transfer for a specific property, proposed terms of transfer may include but are not limited to: (1) final property inspection; (2) specification of structures and improvements to remain on the property after Decommissioning and Facilities Removal; (3) liability protection for the State, or designated third party transferee, and the DRE, for any harm arising from post-transfer Decommissioning or power operations at the property; (4) liability protection for the State, or designated third party transferee, for any harm arising from post-transfer Facilities Removal by the DRE at the property; (5) easements or other property interests necessary for access to and continued operation of PacifiCorp transmission and distribution system assets that will remain on the property; and (6) notice or acknowledgement of the State's claim of ownership to beds and banks of the Klamath River. The DRE shall be a party to the transfer document as necessary and appropriate. The consideration required for transfer of a property to a State or third party transferee under this section shall be limited to the liability protections and other benefits conferred upon PacifiCorp and the DRE under this Settlement. Transfer of Parcel B lands shall be subject to applicable regulatory approvals and the reservations set forth in Section 1.6.

D. PacifiCorp shall convey Parcel B lands to the DRE, after the DRE provides Notice to the Parties and FERC that all necessary permits and approvals have been obtained for Facility Removal, and all contracts necessary for Facility Removal have been finalized. PacifiCorp shall convey all right, title, and interest in a subset of the Parcel B lands

designated on Exhibit 3 as lands associated with each Facility to the State or third party transferee subject to the DRE's possessory interest, consistent with the terms of this Settlement, including the Facilities, underlying lands, and appurtenances as further described through surveys and land descriptions. The DRE shall hold the underlying land for each Facility in trust for the benefit of the State or third party transferee. This public trust possessory interest in the DRE shall be controlled by the terms of the Settlement, the Definite Plan, and the transfer document. At the conclusion of Facilities Removal, the DRE will release the underlying land to the State or third party transferee. Upon transfer of ownership of all Facilities, PacifiCorp shall convey to the State or third party transferee all right, title, and interest in all Parcel B lands not already transferred to the DRE in trust, as further described through surveys and land descriptions, without restriction of possessory interest for the DRE. If transfer of a specific property for any reason is not consummated in a manner achieving the intent set forth in Section 7.6.4.A, PacifiCorp, the applicable State, and the DRE shall Meet and Confer in accordance with Section 8.7.

E. Notwithstanding any provision hereof, in the event either State accepts title to any portion of Parcel B lands, the State of Oregon and the State of California retain the right to transfer their ownership to any third party for any purpose.

7.6.5 PacifiCorp Water Rights

A. PacifiCorp shall assign its revised hydroelectric water rights to the OWRD for conversion to an instream water right pursuant to ORS 543A.305, and OWRD shall take actions to effect such conversion, in accordance with the process and conditions set forth in *Water Right Agreement between PacifiCorp and Oregon* (Exhibit 1). Nothing in this Section 7.6.5 or Exhibit 1 is intended in any way to affect, diminish, impair, or determine any federally-reserved or state law-based water right that the United States or any other person or entity may have in the Klamath River.

B. Except as provided in this paragraph, within 90 days of completion of Facilities Removal at the Copco No. 1, Copco No. 2 and Iron Gate Facilities, respectively, PacifiCorp shall submit a Revocation Request to the California State Water Resources Control Board for License No. 9457 (Application No. 17527), and shall notify the State Water Resources Control Board of its intent to abandon its hydroelectric appropriative water rights at the Copco No. 1 and Copco No. 2 Facilities, as applicable, as identified in Statement of Water Diversion and Use Nos. 15374, 15375, and 15376. Should ongoing operations of the Iron Gate Hatchery or other hatchery facilities necessitate

continued use of water under License No. 9457 (Application No. 17527) beyond 90 days after completion of Facilities Removal, PacifiCorp shall consult with the Department of Fish and Wildlife and the State Water Resources Control Board and shall take actions directed by such Department and Board as are necessary to ensure a sufficient water supply to the Iron Gate Hatchery or other hatchery facilities under License No. 9457.

7.6.6 PacifiCorp Hatchery Facilities

The PacifiCorp Hatchery Facilities within the State of California shall be transferred to the State of California at the time of transfer to the DRE of the Iron Gate Hydro Development or such other time agreed by the Parties, and thereafter operated by the California Department of Fish and Wildlife with funding from PacifiCorp as follows:

A. Hatchery Funding

PacifiCorp will fund 100 percent of hatchery operations and maintenance necessary to fulfill annual mitigation objectives developed by the California Department of Fish and Wildlife in consultation with the National Marine Fisheries Service. This includes funding the Iron Gate Hatchery facility as well as funding of other hatcheries necessary to meet ongoing mitigation objectives following Facilities Removal. Hatchery operations include development and implementation of a Hatchery Genetics Management Plan as well as a 25% constant fractional marking program. Funding will be provided for hatchery operations to meet mitigation requirements and will continue for eight years following the Decommissioning of Iron Gate Dam. PacifiCorp's eight-year funding obligation assumes that dam removal will occur within one year of cessation of power generation at Iron Gate Dam. If Facilities Removal occurs after one year of cessation of power generation at Iron Gate Dam, then the Parties will Meet and Confer to determine appropriate hatchery funding beyond the eight years.

B. Hatchery Production Continuity

PacifiCorp will fund a study to evaluate hatchery production options that do not rely on the current Iron Gate Hatchery water supply. The study will assess groundwater and surface water supply options and water reuse technologies that could support hatchery production in the absence of Iron Gate Dam. The study may include examination of local well records and increasing production potential at existing or new facilities in the Klamath Basin as well as development of a test well or groundwater supply well. Based on the study results and with the approval of the California Department of Fish and Wildlife and the National Marine Fisheries

Service, PacifiCorp will provide one-time funding to construct and implement the measures identified as necessary to continue to meet current mitigation production objectives for a period of eight years following the Decommissioning of Iron Gate Dam. PacifiCorp's eight-year funding obligation assumes that Facilities Removal will occur within one year of cessation of power generation at Iron Gate Dam. If dam removal occurs after one year of cessation of power generation at Iron Gate Dam, then the Parties will Meet and Confer to determine appropriate hatchery funding beyond the eight years. Production facilities capable of meeting current hatchery mitigation goals must be in place and operational upon removal of Iron Gate Dam. PacifiCorp shall not be responsible for funding hatchery programs, if any, necessary to reintroduce anadromous fish in the Klamath basin.

8. General Provisions

8.1 Term of Settlement

The term of this Settlement shall commence on the Effective Date and shall continue until Facilities Removal has been fully achieved and all conditions of this Settlement have been satisfied, unless terminated earlier pursuant to Section 8.11.

8.2 Effectiveness

The KHSA was effective upon execution on February 18, 2010 ("Effective Date"). The KHSA as amended will take effect when it is executed by the signatories to the 2016 AIP ("Amendment Effective Date").

8.3 Successors and Assigns

This Settlement shall apply to, be binding on, and inure to the benefit of the Parties and their successors and assigns, unless otherwise specified in this Settlement. Except as provided by Section 7.1.10, no assignment may take effect without the express written approval of the other Parties, which approval will not be unreasonably withheld.

8.4 Amendment

Except as otherwise expressly provided in Section 8.11.3, this Settlement may only be amended in writing by all Parties still in existence, including any successors or assigns. The Public Agency Parties may also obtain public input on any such modifications as required by Applicable Law. A Party may provide Notice of a proposed amendment at any time. The Parties agree to meet in person or by teleconference within 20 days of receipt of Notice to discuss the proposed amendment.

8.5 Notices

Any Notice required by this Settlement shall be written. Notice shall be provided by electronic mail, unless the sending Party determines that first-class mail or an alternative form of delivery is more appropriate in a given circumstance. A Notice shall be effective upon receipt, but if provided by U.S. Mail, seven days after the date on which it is mailed. For the purpose of Notice, the list of authorized representatives of the Parties as of the Effective Date is attached as Appendix K. The Parties shall provide Notice of any change in the authorized representatives designated in Appendix K, and PacifiCorp shall maintain the current distribution list of such representatives. The Parties agree that failure to provide PacifiCorp with current contact information will result in a waiver of that Party's right to Notice under this Settlement. The Party who has waived Notice may prospectively reinstate its right to Notice by providing current contact information to PacifiCorp.

8.6 Dispute Resolution

All disputes between Parties arising under this Settlement shall be subject to the Dispute Resolution Procedures stated herein. The Parties agree that each such dispute shall be brought and resolved in a Timely manner.

8.6.1 Cooperation

Disputing Parties shall devote such resources as are needed and as can be reasonably provided to resolve the dispute expeditiously. Disputing Parties shall cooperate in good faith to promptly schedule, attend, and participate in the dispute resolution.

8.6.2 Costs

Unless otherwise agreed among the Disputing Parties, each Disputing Party shall bear its own costs for its participation in these Dispute Resolution Procedures.

8.6.3 Non-Exclusive Remedy

These Dispute Resolution Procedures do not preclude any Party from Timely filing and pursuing an action to enforce an obligation under this Settlement, or to appeal a Regulatory Approval inconsistent with the Settlement, or to enforce a Regulatory Approval or Applicable Law; provided that such Party shall provide a Dispute Initiation Notice and, to the extent practicable, undertake and conclude these procedures, before such action.

8.6.4 Dispute Resolution Procedures

A. Dispute Initiation Notice

A Party claiming a dispute shall give Notice of the dispute within seven days of becoming aware of the dispute. Such Notice shall describe: (1) the matter(s) in dispute; (2) the identity of any other Party alleged to have not performed an obligation arising under this Settlement or Regulatory Obligation; and (3) the specific relief sought. Collectively, the Party initiating the procedure, the Party complained against, and any other Party which provides Notice of its intent to participate in these procedures, are "Disputing Parties."

B. Informal Meetings

Disputing Parties shall hold at least two informal meetings to resolve the dispute, commencing within 20 days after the Dispute Initiation Notice, and concluding within 45 days of the Dispute Initiation Notice unless extended upon mutual agreement of the Disputing Parties. If the Disputing Parties are unable to resolve the dispute, at least one meeting will be held within the 45 days at the management level to seek resolution.

C. Mediation

If the dispute is not resolved in the informal meetings, the Disputing Parties shall decide whether to use a neutral mediator. The decision whether to pursue mediation, and if affirmative the identity and allocation of costs for the mediator, shall be made within 75 days after the Dispute Initiation Notice. Mediation shall not occur if the Disputing Parties do not unanimously agree on use of a mediator, choice of mediator, and allocation of costs. The mediation process shall be concluded not later than 135 days after the Dispute Initiation Notice. The above time periods may be shortened or lengthened upon mutual agreement of the Disputing Parties.

D. Dispute Resolution Notice

The Disputing Parties shall provide Notice of the results of the Dispute Resolution Procedures. The Notice shall: (1) restate the disputed matter, as initially described in the Dispute Initiation Notice; (2) describe the alternatives which the Disputing Parties considered for resolution; and (3) state whether resolution was achieved, in whole or part, and state the specific relief, including timeline, agreed to as part of the resolution. Each Disputing Party shall promptly implement any agreed resolution of the dispute.

8.7 Meet and Confer

8.7.1 Applicability

The Meet and Confer procedures in this Section 8.7 shall apply upon the occurrence of certain events or failure to occur of certain events as specifically required in this Settlement.

8.7.2 Meet and Confer Procedures

A. Any Party may initiate the Meet and Confer procedures by sending Notice: (1) describing the event that requires the Parties to confer, and (2) scheduling a meeting or conference call.

B. The Parties will meet to discuss the problem and identify alternative solutions. The Parties agree to dedicate a reasonable amount of time sufficient to resolve the problem.

C. The Meet and Confer procedures will result in: (1) amendment pursuant to Section 8.4; (2) termination or other resolution pursuant to the procedures of Section 8.11; or (3) such other resolution as is appropriate under the applicable section.

8.8 Remedies

This Settlement does not create a cause of action in contract for monetary damages for any alleged breach by any Party of this Settlement. Neither does this Settlement create a cause of action in contract for monetary damages or other remedies for failure to perform a Regulatory Obligation. The Parties reserve all other existing remedies for material breach of the Settlement; provided that Section 8.11 shall constitute the exclusive procedures and means by which this Settlement can be terminated.

8.9 Entire Agreement

This Settlement contains the complete and exclusive agreement among all of the Parties with respect to the subject matter thereof, and supersedes all discussions, negotiations, representations, warranties, commitments, offers, agreements in principle, and other writings among the Parties, including the 2008 AIP and 2016 AIP, before the Amendment Effective Date of this Settlement, with respect to its subject matter. Appendices B, C, D, F, H, K, and L are hereby incorporated by reference into this Settlement as if fully restated herein. Exhibits 1 through 4 are attached to this Settlement for informational purposes only and are not incorporated by reference except as otherwise noted herein.

8.10 Severability

This Settlement is made on the understanding that each provision is a necessary part of the entire Settlement. However, if any provision of this Settlement is held by a Regulatory Agency or a court of competent jurisdiction to be invalid, illegal, or unenforceable: (1) the validity, legality, and enforceability of the remaining provisions of this Settlement are not affected or impaired in any way; and (2) the Parties shall negotiate in good faith in an attempt to agree to another provision (instead of the provision held to be invalid, illegal, or unenforceable) that is valid, legal, and enforceable and carries out the Parties' intention to the greatest lawful extent under this Settlement.

8.11 Termination

8.11.1 Potential Termination Events

This Settlement shall be terminable if one of the following events occurs and a cure for that event is not achieved pursuant to Section 8.11.3:

A. A condition precedent to license transfer set forth in Section 7.1.4 is not met;

B. The Oregon PUC or California PUC do not implement the funding provisions set forth in Sections 4.1 through 4.6;

C. Conditions of any Regulatory Approval of Interim Measures, denial of Regulatory Approval of Interim Measures including the failure Timely to approve ESA incidental take authorization, or results of any litigation related to this Settlement are materially inconsistent with the provisions of Section 6.1 through 6.3 and Appendices C and D;

D. Conditions or denial of any Regulatory Approval of Facilities Removal or the results of any litigation about such removal, are materially inconsistent with the Settlement;

E. The DRE notifies the Parties that it cannot proceed with Facilities Removal because it cannot obtain all permits and contracts necessary for Facilities Removal despite its good faith efforts; or

F. California, Oregon, the Federal Parties, or PacifiCorp is materially adversely affected by another Party's breach of this Settlement.

8.11.2 Definitions for Section 8.11

A. For purposes of this section and Section 7.2.1.C, "materially inconsistent" means diverging from the Settlement or part thereof in a manner that: (1) fundamentally changes the economics or

liability protection such that a Party no longer receives the benefit of the bargain provided by this Settlement; or (2) frustrates the fundamental purpose of this Settlement such that Facilities Removal or the underlying purposes of Interim Measures cannot be accomplished. Events occurring independent of this Settlement, other than those identified in Section 8.11.1, shall not be construed to create a material inconsistency or materially adverse effect.

B. For purposes of this section, "materially adversely affected" means that a Party no longer receives the benefit of the bargain due to: (1) fundamental changes in the economics or liability protection; or (2) frustration of the fundamental purpose of this Settlement such that Facilities Removal or the underlying purposes of Interim Measures cannot be accomplished.

C. For purposes of this section, a "result of any litigation" is materially inconsistent with this Settlement or a part thereof if a Party is materially adversely affected by: (1) costs to defend the litigation; or (2) a final order or judgment.

8.11.3 Cure for Potential Termination Event

A. A Party that believes that a potential termination event specified in Section 8.11.1 has occurred shall provide Notice.

(1) The Parties shall use the Meet and Confer Procedures specified in Section 8.7 to consider whether to deem the event to conform to the Settlement, or adopt a mutually agreeable amendment to this Settlement. These procedures shall conclude within 90 days of Notice.

(2) If these procedures do not resolve the potential termination event, the Federal Parties, the States, the DRE if a Party, and PacifiCorp may, within 90 days thereafter, agree to an amendment, or deem the event to conform to the Settlement; otherwise, this Settlement shall terminate. In no event shall any amendment under this subsection provide for Facilities Removal with respect to fewer than four Facilities.

B. If the Federal Parties, the States, the DRE if a Party, and PacifiCorp disagree whether a potential termination event specified in Section 8.11.1 has occurred, these Parties shall follow the Dispute Resolution Procedures in Section 8.6 to attempt to resolve that dispute. If such a Notice of Dispute is filed while the Meet and Confer Procedures referenced in 8.11.3.A are ongoing, those Meet and Confer Procedures are deemed concluded, subject to being recommenced in accordance

with the remainder of this subsection. Upon conclusion of the Dispute Resolution Procedures in Section 8.6, the Federal Parties, the States, the DRE if a Party, and PacifiCorp shall issue a Notice of Dispute Resolution.

(1) If, in the Notice of Dispute Resolution, the Federal Parties, the States, and PacifiCorp agree that a potential termination event has occurred, or agree to consider whether a cure could be achieved, the further procedures stated in Section 8.11.3.A(1) and (2) above shall apply.

(2) If, in the Notice of Dispute Resolution, the Federal Parties, the States, the DRE if a Party, and PacifiCorp disagree whether a potential termination event has occurred, this Settlement shall terminate unless a Party seeks and obtains a remedy preserving the Settlement under Applicable Law.

C. A Party may reasonably suspend performance of its otherwise applicable obligations under this Settlement, upon receipt of Notice and pending a resolution of the potential termination event as provided in Section 8.11.3.A or B.

D. If the Federal Parties, the States, the DRE if a Party, and PacifiCorp, pursuant to the procedures in Section 8.11.3.A, agree to an amendment or other cure to resolve a potential termination event absent agreement by all other Parties pursuant to Section 8.4, any other Party may accept the amendment by Notice. If it objects, such other Party: (1) may seek a remedy regarding the potential termination event that resulted in the disputed amendment, to the extent provided by Section 8.8; (2) may continue to suspend performance of its obligations under this Settlement; and (3) in either event shall not be liable in any manner as a result of its objection or the suspension of its performance of its obligations under this Settlement.

E. The Parties shall undertake to complete the applicable procedures under this section within six months of a potential termination event.

8.11.4 Obligations Surviving Termination

A. Upon termination, all documents and communications related to the development, execution, or submittal of this Settlement to any agency, court, or other entity, shall not be used as evidence, admission, or argument in any forum or proceeding for any purpose to the fullest extent allowed by Applicable Law, including 18 C.F.R. § 385.606. This provision does not apply to the results of studies or other technical information developed for use by a Public Agency Party.

This provision does not apply to any information that was in the public domain prior to the development of this Settlement or that became part of the public domain at some later time through no unauthorized act or omission by any Party. Notwithstanding the termination of this Settlement, all Parties shall continue to maintain the confidentiality of all settlement communications.

This provision does not prohibit the disclosure of: (1) any information held by a federal agency that is not protected from disclosure pursuant to the Freedom of Information Act or other applicable law; (2) any information held by a state or local agency that is not protected from disclosure pursuant to the California Public Records Act, the Oregon Public Records Law, or other applicable state or federal law; or (3) disclosure pursuant to Section 1.6.8.

B. The prohibitions in Section 1.6.8 survive termination of this Settlement.

8.12 No Third-Party Beneficiaries

This Settlement is not intended to and shall not confer any right or interest in the public, or any member thereof, or on any persons or entities that are not Parties hereto, as intended or expected third-party beneficiaries hereof, and shall not authorize any non-Party to maintain a suit at law or equity based on a cause of action deriving from this Settlement. The duties, obligations, and responsibilities of the Parties with respect to third parties shall remain as imposed under Applicable Law.

8.13 Elected Officials Not to Benefit

No Member of or Delegate to Congress, Resident Commissioner, or elected official shall personally benefit from this Settlement or from any benefit that may arise from it.

8.14 No Partnership

Except as otherwise expressly set forth herein, nothing contained in this Settlement is intended or shall be construed to create an association, trust, partnership, or joint venture, or impose any trust or partnership duty, obligation, or liability on any Party, or create an agency relationship between or among the Parties or between any Party and any employee of any other Party.

8.15 Governing Law

8.15.1 Contractual Obligation

A Party's performance of an obligation arising under this Settlement shall be governed by (1) applicable provisions of this Settlement, and (2) Applicable Law for obligations of that type.

8.15.2 Regulatory Obligation

A Party's performance of a Regulatory Obligation, once approved as proposed by this Settlement, shall be governed by Applicable Law for obligations of that type.

8.15.3 Reference to Applicable Law

Any reference in this Settlement to an Applicable Law shall be deemed to be a reference to such law in existence as of the date of the action in question.

8.16 Federal Appropriations

To the extent that the expenditure or advance of any money or the performance of any obligation of the Federal Parties under this Settlement is to be funded by appropriations of funds by Congress, the expenditure, advance, or performance shall be contingent upon the appropriation of funds by Congress that are available for this purpose and the apportionment of such funds by the Office of Management and Budget. No breach of this Settlement shall result and no liability shall accrue to the United States in the event such funds are not appropriated or apportioned.

8.17 Confidentiality

The confidentiality provisions of the *Agreement for Confidentiality of Settlement Communications and Negotiations Protocol Related to the Klamath Hydroelectric Project*, as it may be amended, shall continue as long as this Settlement is in effect.

9. Execution of Settlement

9.1 Signatory Authority

Each signatory to this Settlement certifies that he or she is authorized to execute this Settlement and to legally bind the entity he or she represents, and that such entity shall be fully bound by the terms hereof upon such signature without any further act, approval, or authorization by such entity.

9.2 Signing in Counterparts

This Settlement may be executed in any number of counterparts, and each executed counterpart shall have the same force and effect as if all signatory Parties had signed the same instrument. The signature pages of counterparts of this Settlement may be compiled without impairing the legal effect of any signatures thereon.

9.3 New Parties

Except as provided in Section 9.4 any entity listed on pages 1 through 2 of this Settlement that signs this Settlement on or before December 31, 2016, will become a Party to this Settlement. After December 31, 2016, any entity listed on pages 1 through 2 of this Settlement may become a Party through an amendment of this Settlement in accordance with Section 8.4. After 90 days from the Amendment Effective Date, an entity not listed on pages 1 through 2 of this Settlement may become a Party through an amendment of this Settlement in accordance with Section 8.4.

9.4 DRE and Liability Transfer Corp. as Parties

The Parties expect that the DRE will become a Party by executing this Settlement within 90 days of the Amendment Effective Date. No action by any other Party is necessary for the DRE to become a Party. If the DRE assigns any of its responsibilities to a Liability Transfer Corp. as described in Section 7.1.10 and Appendix L, the Liability Transfer Corp. shall become a Party by executing this Settlement. No action by any other Party is necessary for the Liability Transfer Corp. to become a Party.

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DOCKET NO UG 527 – CERTIFICATE OF SERVICE

I hereby certify that, on this 18th day of March, 2026, I served the foregoing **CUB 300_CONF and CUB 315_CONF** in UG 527 upon the Commission and each party designated to receive confidential information pursuant to General Protective Order No. 23-132 by secure 7-zip file.

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Respectfully submitted,

/s/ Lizzie Lesch-Abhaya

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